Northpower

2023 – 2033

Asset Management Plan

March 2023

Northpower

Head Office:
Northpower Limited 28
Mt Pleasant Road
Raumanga, Whangārei 0110
New Zealand

Postal Address:
Northpower Limited
Private Bag 9018
Whangārei Mail Centre 0148
New Zealand

Ph: 09 430 1803
Fax: 09 430 1804
Email: info@northpower.com
Web: www.northpower.com

INTRODUCTION FROM OUR CHIEF EXECUTIVE

Tēnā koutou katoa

As we publish our 2023 AMP, our region is still coming to terms with the impacts of Cyclone Gabrielle.

I'd like to extend a huge thank you to our communities for their understanding and patience as our teams gave their absolute all to 'getting the lights back on'. It was a remarkable example of the strength and solidarity of regional communities, and the value of Civil Defence Emergency Management (CDEM) processes that rolled out seamlessly across the region to ensure critical infrastructure was repaired and reinstated promptly and safely.

Cyclone Gabrielle was however, a sobering reminder of the destructive nature of severe weather events and the fact that climate change is likely to make weather patterns in New Zealand less predictable, and more extreme over time. Accepting this reality and adapting our approach to long term infrastructure investment to ensure resilience in the face of severe weather, is an important and emerging area of discussion across our industry and within Northpower.

Northpower believes that ensuring appropriate renewal and modernisation of existing assets is a critical foundational element for delivering resilient infrastructure, and this AMP includes a material uplift in expenditure in this area to ensure Northpower's networks continue to provide a robust physical platform. We are committed to making the significant level of investment necessary to ensure a reliable, resilient, and modern distribution network for our region.

The energy transition also provides opportunities to enhance regional and community resilience in the face of extreme weather. We see the emergence of renewable energy generation at scale in Northland as a positive development, both in providing renewable energy to our community in good times, but also in providing local energy resilience in the event of damage to key assets to and around the region.

For Northland, a renewable future, is also a resilient future. The opportunity is in our hands to create a region where we produce 100% of the energy our community needs and have generation on our doorstep when the worst happens. As a Northland owned company, Northpower is embracing that future. We believe it's a future worth creating.

Ngā mihi

Andrew McLeod

Chief Executive

EXECUTIVE SUMMARY

Introducing our 2023 asset management plan

This is Northpower's 2023 asset management plan (AMP). It sets out our approach to managing our electricity network assets and related expenditure over the next 10 years, from 1 April 2023 to 31 March 2033.

The AMP summarises and explains our asset management approach for our customer owners and other stakeholders. It complies with the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination.

Our AMP is informed by our Statement of Corporate Intent (SCI), our group strategy, and our electricity business plan. It explains how we will deliver on our commitments to provide a safe, secure, and reliable electricity distribution service.

Our AMP outlines how we will invest to maintain our assets, cater for growth, and transform our network over the next 10 years to meet the evolving needs of our consumer owners.

Reflecting improvements to our asset management approaches, this 2023 AMP has been significantly revised and expanded from previous versions. This includes refining and restructuring content, simplifying asset related discussions, and making the content more accessible for stakeholders. We hope the changes to our AMP will make it easier for customers and stakeholders to connect with us.

Background to our 2023 AMP

Impact of Cyclone Gabrielle

The planning and engineering analysis underpinning our 2023 AMP was largely undertaken prior to the destructive weather our region experienced in February.

Following efforts to 'get the lights back on', we have turned our focus to understanding the rebuild required. Adapting our long-term investment plans to ensure resilience in the face of severe weather will be a key part of this. Timely renewal and modernisation of existing assets will be critical. We are committed to making the significant level of investment necessary to ensure a reliable, resilient, and modern distribution network for our region.

Our work programmes and related expenditure forecasts need to be refined and updated. We will provide further detail on these in our 2024 asset management plan update.

New Zealand is entering a critical period as we look to decarbonise and electrify our economy. We are seeing technologies such as wind, solar, battery storage, and electric vehicles become mainstream, as costs progressively decline. It's an exciting time and distribution networks are at the forefront as key enablers of the transition.

As part of this transition, we expect our customers to take up opportunities to generate a portion of their own energy and adopt new energy technologies, particularly electric vehicles. Our vision for the future is one where our electricity network not only provides a safe and reliable link to existing energy sources, but also helps our customers to unlock more flexibility, innovative solutions, and cost-effective services.

To support this, we are committed to managing our assets in a prudent way over the long term. This means developing the network to serve new customers and supporting the evolving demand of existing customers.

New Zealand is entering a critical period as we look to decarbonise and electrify our economy.

It's a transition we anticipated and are well prepared for. Over the past five years we've stepped up investment levels, strengthened the network backbone, and invested in modern operational systems and customer capability.

Alongside the opportunities we see over the coming years, we know we will face some challenges. Our asset management activities take place in a wider environment with multiple drivers and influencing factors. How we manage these external factors is key to our asset management approach. These factors include the increasing impacts of climate change, the need for increasing network resilience, and increasing renewal needs. A key part of our response to addressing these is to continually improve our underlying capabilities.

This AMP sets out some of the main challenges and opportunities we face and the initiatives we are undertaking to address them.

Supporting our communities

Northpower's electricity network spans the Whangārei and Kaipara districts, and connects the national electricity grid to our customers' homes and workplaces. We provide residential and business customers a safe, secure, and reliable electricity distribution service. These customers are also our owners – every customer connected to our network is an owner through the Northpower Electric Power Trust.

Our overarching purpose is to generate value for the regions of Kaipara and Whangārei from infrastructure ownership. We pass on the benefits of ownership to our customers through discounts on distribution charges (via their power bills) and dividends through the trust.

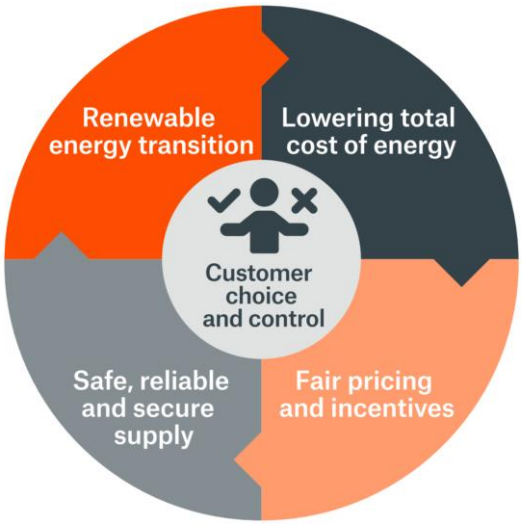
Enabling our communities to thrive by powering a more sustainable future.

Customer views and feedback are incorporated into our decision-making through regular surveys, market research, engagement with iwi and community groups, and ongoing customer feedback. This allows us to improve customer experience and gain a deeper understanding of our customers' needs, now and in the future.

We engage with our communities through a range of channels and actively consult with them on what matters most to them and their experience of dealing with us. Our dedicated customer experience team puts customers at the heart of all we do.

Consistent themes from our engagement include:

- customer choice and control
- renewable energy transition
- safe, reliable, and secure supply
- lowering total cost of energy
- fair pricing and incentives.

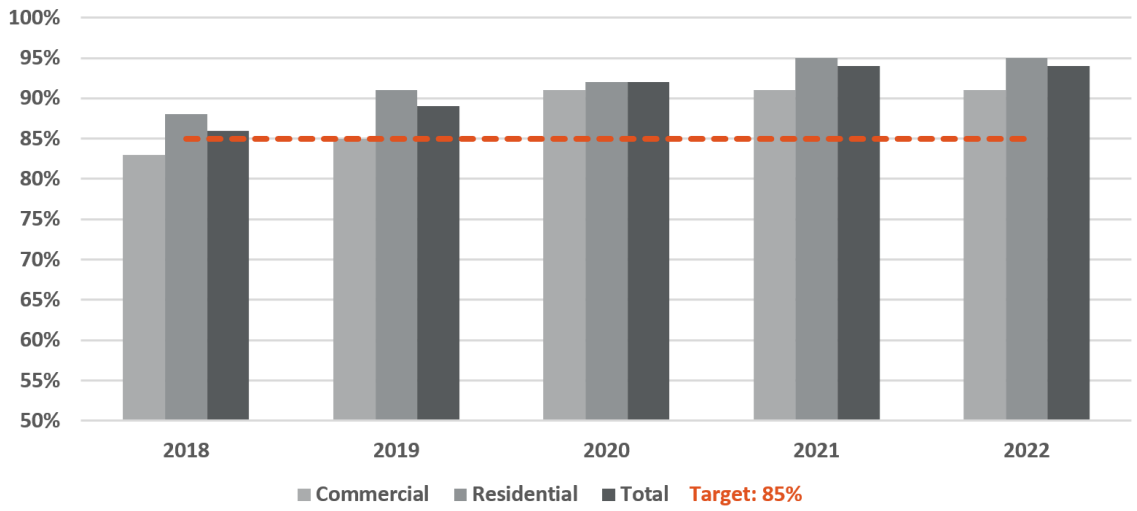


As part of our 'your energy future' initiative, we continue to connect with customers and stakeholders. We use our latest customer survey to develop a better understanding of our customers' needs and concerns. Customers tell us that ensuring the network is able to manage their future energy needs and choices is important. We recognise that energy choices can be complex, and our aim is to make it easier for our customers to make informed energy choices.

Delivering for customers

A key focus is ensuring we meet our customers' expectations. We have a long-standing performance target for customer satisfaction of at least 85%. We are consistently achieving this target. In our last annual survey, 94% of customers were satisfied or highly satisfied (an increase from 92% in 2020). This was made up of 91% satisfaction amongst commercial customers and 95% satisfaction amongst residential customers.

Customer satisfaction results



Delivering a cost-effective service

We recognise that energy hardship is a growing issue in our communities, so one of our key goals is to help customers reduce their total energy costs. Our objective is to support healthy homes in our communities with access to safe, reliable, and affordable energy. We

are committed to helping our customers manage their energy usage and be more energy efficient.

Our consumer outreach programme helps Northlanders with practical energy saving advice and assistance to reduce total electricity costs. Working with community partners to reach households in need, last year we delivered personalised electricity advice and support to over 1,000 households. This practical help includes home energy assessments, helping customers find the best retail plans, and providing free LED lightbulbs.

We need to continually improve the way we do things, making sure that our investment decisions are as efficient as practical. This includes adopting a whole-of-life approach to make trade-offs between Opex and Capex over the full lives of our assets. This supports more cost effective asset management, lowering costs over time.

We are refining the way we charge our customers to ensure our charges are equitable, reflect actual cost, and remain fair as new energy solutions emerge. We have a strong focus on managing our wider business operations in a way that will enable us to lift the level of contribution we provide our customers over time. This includes an ongoing focus on costs through continuous improvement and efficiency initiatives.

Partnering with stakeholders

Delivering for our communities needs to be underpinned by meaningful, effective engagement with our customer owners. We do so through a range of channels, actively consulting with them on what matters most to them and their experience in dealing with us. We continue to increase our efforts to work more closely and collaboratively with stakeholders, mana whenua, community leaders, social and health organisations, and government agencies.

Ongoing meetings with stakeholders help us understand what is important to them and how we can improve our service. We are improving the way we work with customers by streamlining and modernising the ways they can engage with us. We engage with our community to understand their needs and actively partner with iwi and mana whenua to make informed decisions. We invest in and operate our assets in a way that respects and cares for cultural aspects.

Your energy future

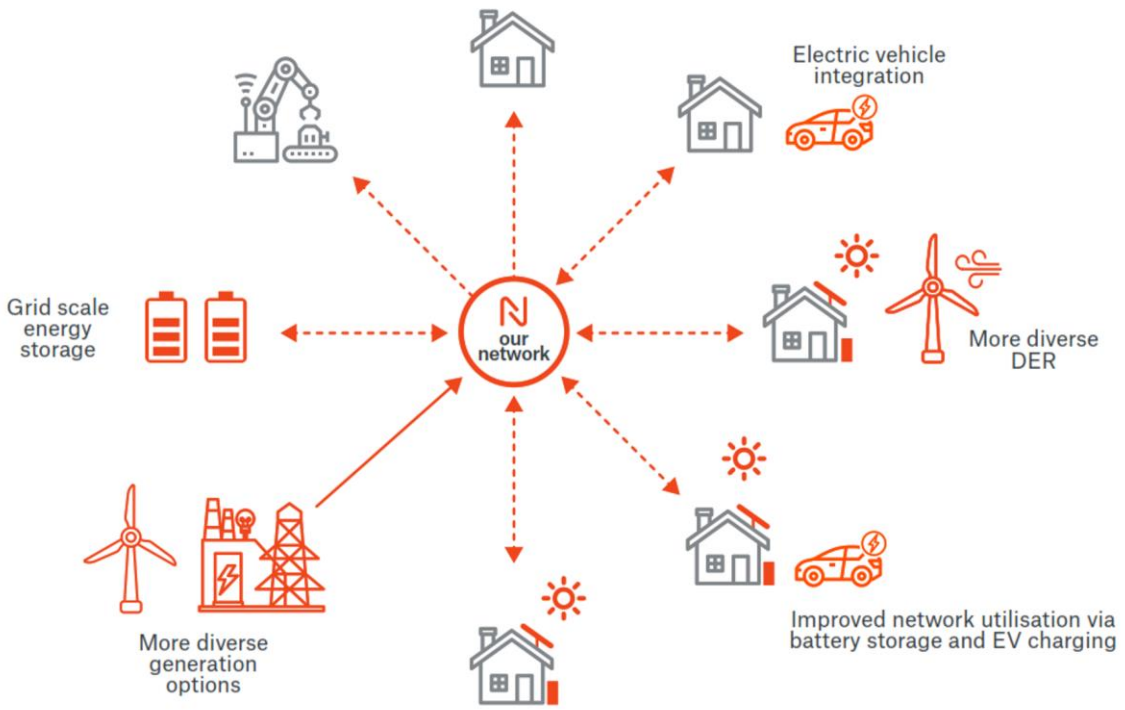
The ongoing energy transition is the beginning of a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use. We are excited by this transition and the increased uptake of new renewable energy supply options and technologies, such as rooftop solar and electric vehicles. We see these as complementary to our current energy supply arrangements, and we need to continue to connect customers simply and efficiently.

We are committed to supporting this natural integration of new energy solutions, and our networks are a key platform to support their implementation. They have the potential to unlock more cost-effective energy solutions and help customers reduce overall energy costs while supporting energy decarbonisation.

Supporting our communities in accessing new energy solutions, while retaining our focus on a safe, reliable, and cost-effective service.

As shown below, alongside large amounts of EVs, we envisage connecting small and large DER[1] to our distribution network (e.g. wind farms, solar farms, batteries). In preparation, we are making investments now to ensure our network can support these technologies, while remaining prudent about uptake scenarios.

Supporting our customers' energy future



Supporting new generation

We are investing in monitoring and control systems to facilitate expected increases in distribution generation. These changes will ensure our network can accommodate increasing numbers and sizes of DER installations. We take a balanced approach to these installations as we need to manage a range of customer outcomes.

We engage with customers seeking to connect and discuss their proposed solutions. Our aim is to make it easy for customers to understand their connection options and associated

[1] Distributed energy resources are located within the distribution network and include small and large scale generation (such as solar photo-voltaic systems and wind power), batteries, electric vehicles connected to smart two-way chargers, and other new smart technologies that will see our homes and business play an active role in the operation of future power systems.

costs. We believe it is important to support connecting parties so they can make informed choices.

We are seeing a significant increase in large-scale distributed generation connection requests on our network. The majority of these are located in rural areas where network demand is relatively low. We expect that these connections will require some significant upgrades. We continue to work with our generation customers to enable them to connect to our network as economically as possible.

Additionally, we are partnering with solution providers, other distribution businesses, and industry parties to share learnings, develop future-proofed standards, and ensure our approach is consistent with good practice.

Innovation and new technologies

As the energy market evolves and technologies develop, our network will need to adapt. We expect this to include changes to our control systems, the introduction of flexibility services, new pricing models to optimise network utilisation, and robust technical standards. We actively look to adopt innovations and new technologies where they will improve the services we deliver. This will need to be underpinned by solid underlying asset management practices to incorporate these new power flows and commercial relationships. With the uptake of DER and new technology, more opportunities exist to deploy non-network solutions and leverage them to cost-effectively address network constraints.

Northpower is actively participating in several technical advisory groups that are examining and developing new standards and guides for PV installations, EV charging, and flexibility management.

Our aim is to make it easier for our customers to make informed choices. Technology will enable us to enhance the level of advice and information our customers can access about their service – for example, developing systems that will provide improved information on real-time network status.

The emerging energy future is front of mind for us. We see it as a chance to support our communities so they can access new energy solutions. While doing so we will retain our traditional focus on safe, reliable, and resilient network operation. As we prepare for the future, energy affordability and equity of pricing will remain at the forefront of our strategy.

Managing our electricity assets

The role of our electricity network assets is to deliver a safe, secure, and reliable electricity service to the communities of Whangārei and Kaipara, today and in the future. We need to be a responsible steward of the electricity assets for the benefit of our consumer owners.

Keeping our network safe

Safety is our foremost organisational value. We continually challenge ourselves to protect life, and we put safety and well-being at the heart of everything we do. We continue to take an uncompromising approach to safety and will act when we believe there are safety risks for the public, our staff, and service providers.

As an electricity network owner, we know our assets and some asset management activities may pose hazards to our staff and the general public. We need to proactively safeguard those working on our network, as well as the wider public. Furthermore, as an employer, we aim to ensure an injury-free workplace, and we actively promote the well-being of our people.

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, secure, and resilient in the longer term. We need to manage our asset fleets to maintain their condition and performance to prevent increases in safety risk. Our renewal investments and operations and maintenance activities help ensure our network and our activities do not cause harm to the public, our staff, and service providers.

Our investment plans focus on ensuring our network continues to safely serve communities in Whangārei and Kaipara. While delivering our investment programmes, we will not compromise our efforts to ensure the safety of our staff and the general public. This will always be our foremost priority and it informs everything we do.

A secure network to support growing communities

The Northland region continues to see significant growth, with network peak demand increasing on average 1.2% per year over the last five years. Development around Whangārei, as well as in coastal towns such as Bream Bay, Waipu, and Mangawhai, is the key driver of this growth. Kaipara district continues to grow rapidly; it has been one of the fastest growing regions in the country over the last three years.

Whangārei and Kaipara district councils are forecasting continued increases in population. This will further drive our need to invest in our network to manage increased load growth and ensure we deliver a secure supply.

To meet this ongoing growth, we will invest $64.3 million over the 10-year AMP period. Key investments include the upgrade of our Kensington regional substation, upgrades to our subtransmission network around Whangārei, an additional line and zone substation to supply Mangawhai, a new zone substation and line to supply the Waipu area, and an upgrade of Bream Bay zone substation.

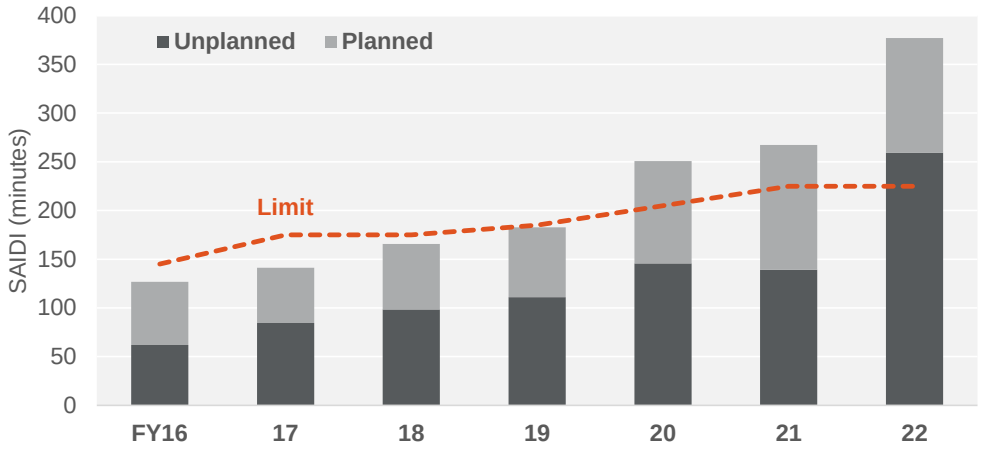
FY23 saw the closure of the New Zealand Refinery, reducing peak demand by approximately 30MW on the Bream Bay grid exit point (GXP). This has led us to reconsider our needs at the Bream Bay GXP. We continue to work through our supply options for this area with Transpower.

Delivering a reliable service

Service reliability is a priority for our customers. The service they receive is influenced by a range of factors, including asset condition, weather, third-party activities, our capacity to respond to incidents, and network security in terms of backup or alternative supply. The levels of reliability we can deliver also reflect historical trade-offs between cost and service. Improving service performance is often a long-term undertaking and has cost implications. Future trade-offs should be based on changing customer preferences and the need to also deliver a safe and resilient service.

Consistent with the wider industry, we measure reliability in terms of duration (SAIDI) and frequency (SAIFI) of interruptions for an average customer.[2] Reflecting their importance, we have set out related reliability targets in our SCI.

Historical reliability performance (SAIDI)



Our network reliability compares well against peer utilities in New Zealand, and we have generally met our reliability targets. However, we are increasingly seeing extreme events skew performance results. In the last three years, we have exceeded our targets due to a number of factors, including lightning (FY21), extreme weather (FY22), and an ongoing rise in outages caused by third-party events. Planned outages to safely undertake maintenance and other works have been increasing as we ramp up our work programmes.

When surveyed, the vast majority of customers want existing service levels to be maintained, and their preferences have been reasonably consistent over the last five years.

Customers are happy with current reliability, but we are increasingly seeing extreme events leading to longer outages.

Some level of outages will always occur. When they happen our customers value good communications and timely information on service restoration. They also have increasing expectations of real-time information about network outages and planned works. We aim to advise customers of planned outages well ahead of time and publish information on both planned works and unplanned outages on our website.

Accurately forecasting reliability performance is challenging, as it is affected by multiple factors such as asset condition, prevailing climate, new network configurations and technologies, and our capability to deliver planned interventions. While Northpower is exempt from price-quality regulation, we updated our network performance measures in FY22 to align with regulated targets applied to other distribution businesses in New Zealand. In the future, these performance metrics will allow better comparisons with other distributors and provide a clearer view of underlying reliability.

[2] System average interruption duration index (SAIDI) measures average length (duration) of outages per customer per year. System average interruption frequency index (SAIFI) reflects number of outages per year for an average customer.

Our reliability performance and future targets are discussed further in Chapter 5.

Renewing our assets

To be a good steward of long-life assets on behalf of our customer owners, we need a thorough understanding of their performance and condition and how these factors contribute to risk on the network. To manage network risk, we need to monitor our assets' condition and performance. Based on this, we maintain and renew assets at the appropriate time. It also requires us to be prudent network operators, ensuring assets are not used in ways that are unsafe or could lead to service interruptions.

Our asset inspection process and defect classification methods have improved, allowing us to model an asset's remaining life more accurately. Using this improved asset information, we are modelling the future health of our assets to understand renewal needs and the appropriate level of residual risk. To maintain appropriate asset health, we prioritise investment in our most critical assets. We are also finalising new asset fleet strategy documents, outlining the performance criteria for managing our asset fleets. This ensures we get the most value from our assets, minimise risk, and continue to make prudent investments.

Asset health modelling

In combination, asset health and asset criticality can be used to estimate the overall risk to our assets. This enables us to prioritise and optimise the timing of asset renewal.

- **Asset health**: is an indicator that represents an asset's proximity to the end of its useful life. This can be used as an indicator of failure likelihood.
- **Criticality**: reflects the impact that an asset failure would have on reliability, safety, and other outcomes. This can be used as an indicator of failure consequence.

Asset health, criticality, and risk modelling provide opportunities to better understand and quantify asset risks and enable defendable fact-based (and prioritised) infrastructure investment decisions.

Effectively managing network risk is a core focus. To ensure we effectively manage the health of our assets and their performance we will accelerate investment in asset renewal and further optimise our maintenance programmes. The ongoing improvements to our asset management systems and processes are helping ensure we optimise the timing of these investments.

Our overhead line assets have large impacts on service reliability and security of supply. They can also pose risks to public safety if a pole fails, or a conductor drops. We plan to increase our crossarm and conductor replacement programmes. Over the next 10 years we expect to spend $179 million on renewing end-of-life overhead assets.

In the coming years we will renew many of our critical assets that entered service in the 1950s and 1960s, such as zone substation power transformers and 33kV and 11kV switchboards. Our forecast renewals for these asset categories are $44 million. This will provide important investment in Northland's energy infrastructure future.

Our improved asset management modelling and forecasting work has been instrumental in helping us quantify the scale of asset ageing and learning how best to sequence those investments to maximise risk reduction while minimising long-term cost.

The level of investment we expect to make over the next decade is an increase on recent levels of expenditure. This is needed to ensure we manage our ageing asset base in a way that ensures a safe, secure, and reliable service for the communities we serve.

A resilient network

Network resilience (the ability to adapt and respond quickly to external impacts) is becoming an urgent priority. A changing climate brings with it more frequent and more powerful storms and floods. In addition, the increasing complexity of our systems, use of automation, and sophistication of cyberattacks highlight the importance of an electricity supply that is resilient to external threats.

The term 'climate change' refers to the change of weather patterns over an extended period of time. Climate modelling and our own recent experiences suggest that extreme weather events will continue to increase in both frequency and intensity over the coming decades, despite global efforts to reduce carbon emissions. These impacts of climate change have the potential to adversely affect the performance and safety of electrical assets. As a result, climate change poses material risks to our network and its performance.

Our assets and operational systems will need to offer increased resilience to extreme or unforeseen events, including those from climate change and cyberattacks. We need to anticipate and adapt to these emerging threats, withstand and absorb their impacts, and recover quickly.

Climate change adaptation

Climate change is a global issue that requires significant and immediate action. The global climate is changing at an accelerated rate and the main driver for this is an increase in greenhouse gas emissions from human activities. With a measure of climatic change already locked in, adaptation to mitigate its impact becomes increasingly important.

The impacts of this changing climate will bring significant direct and indirect changes and challenges. These include a growing frequency of extreme weather events, more prolonged dry periods, ground movement due to higher levels of rain, rising sea levels, and increased coastal flooding and erosion. The severity and frequency of these events will increase over time as climate change continues to accelerate. These events damage, destroy, and compromise the performance of infrastructure, and increase risks to the reliable supply of electricity.

These resilience risks need to be systematically assessed to ensure associated risk and mitigation costs are understood. Without doing so, there is a danger these evolving risks will not be recognised and there will be missed opportunities to address them while this is still relatively feasible.

There is uncertainty in the development of climate change adaptation strategies. We are beginning a journey of climate understanding, response, mitigation, and adaptation. Our

aim is to operate a low-carbon organisation that is resilient to climate impacts. This means engaging our people on the issues and assessing the vulnerabilities of our assets and services in a changing climate.

Our planned investment aims to strengthen network security and resilience to better withstand high impact, low probability events, including the increase in extreme weather events due to climate change. We need to develop planning and modelling capabilities that can effectively manage the risk posed by climate change though prudent and efficient investment.

This is not a challenge we can face on our own. We have joined with the ENA, EEA, and Northland lifelines group to work collaboratively on these issues. We discuss our response to climate change in more detail in Chapter 2.

Cybersecurity

The introduction of digital technologies and enhanced data capabilities create significant operational efficiencies, while transforming the roles and required skills of our future workforce. This increased complexity and disaggregated workforce potentially increases the risk of cyberattacks.

Northpower, as a lifeline utility, needs to address these risks, particularly as cyberattacks become more frequent and sophisticated. We need to maintain effective cyber resiliency that can both combat the rise in cyberattacks and protect internal systems to maintain capability and services.

We will assess our cybersecurity preparedness, including implementing an improvement plan and stabilising and securing our network architecture. Implementing stronger and more sophisticated cybersecurity protections will maintain the resilience and security of our operations and mitigate these threats.

A sustainable future

Our purpose includes Kaitiakitanga, the importance of guardianship of the environment for current and future generations. Northland's spectacular natural landscapes, extensive coastlines, and indigenous flora and fauna need to be preserved and protected.

We take a long-term view of our operations to ensure a sustainable future for Northland. Improved sustainability outcomes can be achieved by facilitating and supporting the development of renewable generation and increased electrification.

> Kaitiakitanga expresses the importance of guardianship of the environment for current and future generations.

We strive to exceed regulatory requirements across our operations and projects. We aim to limit the impacts our assets and activities have on our communities and the environment, as far as practicable. This includes the appropriate disposal of redundant assets, equipment, and hazardous substances. We ensure that materials such as oil, lead, SF_6, and asbestos, which may cause harm to the environment or people's health, are disposed of appropriately. We recycle materials where practical.

We are committed to being environmentally responsible and ensuring we do not cause harm to the environment. We will identify and manage works in cultural sites (urupā, pā, etc) through a collaborative and consultative approach with stakeholders. We strive to protect archaeological sites so we can identify, preserve, and protect heritage structures..

Emissions reduction

Northpower recognises that our network will play a foundational role in the achievement of emission reduction targets in Northland. We recognise the part we should play to support New Zealand's transition to a low-carbon energy future. This is increasingly the case in the context of climate change.

Limiting our carbon footprint is a key focus for us and is reflected in our environment and sustainability strategies. We are proactively managing the emissions produced by our operations.

> The pursuit of a net zero economy will transform the way we generate and consume energy.

More generally, Northpower is committed to making a positive contribution to decarbonisation by investing in more distribution and transmission assets and systems to support Northland's longer-term adaptation needs and electrification plans. Where necessary, we will work with the sector to develop additional capacity to enable the decarbonisation of industry, including increased renewable generation.

Our Planned Expenditure

We are committed to making the investment necessary to ensure we continue to meet the needs of Whangārei and Kaipara communities. Our planned expenditure during the AMP period is $718 million. This level of investment is necessary if we are to continue to manage safety risk, maintain network performance, and prepare our network and operation for the future.

We are renewing and increasing our commitment to ensuring our networks meet our customer owners' needs. Since our 2021 AMP, our forecasts have been refined, in terms of priority and timing, informed by improvements in asset data, risk modelling, and updated asset condition.

> We've lifted investment in network renewals, growth-related upgrades, and customer capability.

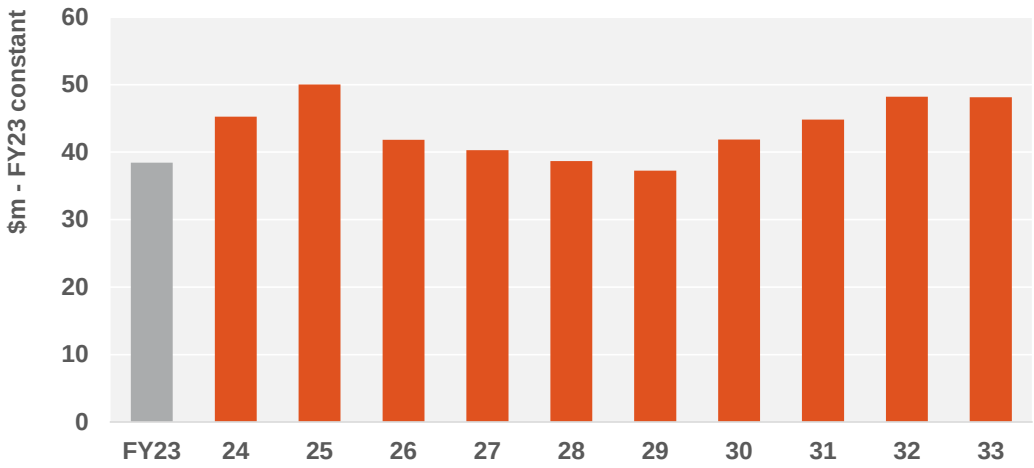
Our expected total capital and operating expenditure profiles over the AMP period are set out below. These forecasts represent our best estimate of network need based on currently available information and reflect our current levels of delivery capability.

Capital expenditure

Our planned capital expenditure (Capex) during the AMP period is set out below. Our Capex forecast of $379 million has increased since our 2021 AMP for the reasons set out in Chapters 9 and 10. It reflects a need to proactively manage our ageing assets and to help ensure we are ready to meet the evolving needs of customers.

In general, the initial years (FY24 to FY26) are more certain and are supported by more detailed plans. For those investments later in the period, we may refine our plans as we obtain updated asset information or refine our risk analysis.

Forecast capital expenditure FY23-FY33



Our Capex profile varies due to the impact of individual, large investments towards the beginning and end of the period. The timing of these growth-driven projects reflects the latest prudent timing for addressing the related constraints. Our underlying renewal programmes have a steady ramp-up throughout the period.

Below we set out some examples of our planned Capex investments.

- Based on improved modelling and better asset data, we plan to increase levels of renewal in our overhead fleets, particularly crossarms and overhead conductors.
- We will carry out several large substation renewal projects, including an upgrade (ODID) at Maungatapere substation.
- We will cater for future growth in several areas, such as Waipu, Mangawhai, and Bream Bay. This includes new substations at Mangawhai and Waipu, a new line between Maungaturoto and Mangawhai, a new line between Marsden and Waipu, and upgrade of the Kensington substation.
- We will increase network resilience in the Whangārei area and make opportunistic improvements during renewal works, e.g. raising assets at flood-prone sites.
- Non-network investments to support future applications include upgrading our management systems and the roll-out of monitoring devices.

Further detail on these investments is set out in Chapters 8 and 9.

We have applied a series of efficiency adjustments to our investment plans, based on a range of expected improvements. Through improvements in planning, work practices, and the increased bundling of works, we expect to reduce our overall cost of delivery.

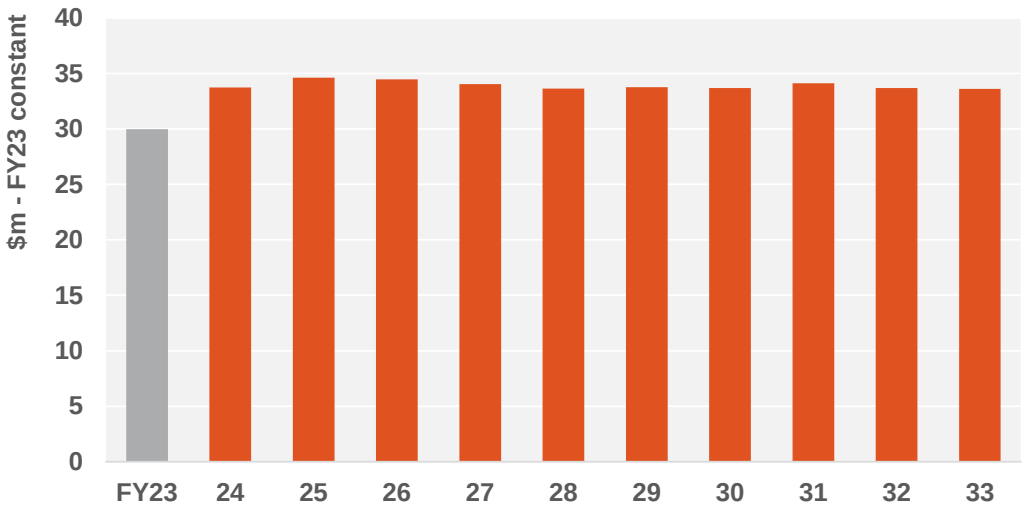
This is a significant level of investment, but this is necessary so that we can replace assets which are reaching the end of their service life, connect new customers, and ensure that current levels of reliability and security can at least be maintained. It will also allow us to

enhance our networks with the necessary supporting infrastructure and operational controls to support the future use of our network.

Operating expenditure

Our planned operating expenditure (Opex) during the AMP period is set out below. Our Opex forecast of $339 million has increased slightly since our 2021 AMP.

Forecast operating expenditure FY23-FY33



Our planned Opex is forecast to be relatively stable over the AMP planning period. It reflects the underlying levels of operations and maintenance we need to undertake, support costs, and people costs in the coming years. Opex related to our transition to 'cloud' based IT services will increase, however this will be offset by reductions to IT related Capex. Consistent with good practice, we plan to optimise our maintenance regimes and rely on more proactive work. We expect reactive work (e.g. repairs) will then reduce.

In the initial two years of the period, we will increase expenditure on several transformation and improvement initiatives. These include:

- digital projects to improve asset management capability and analytics including a new asset management information system
- additional resources to uplift asset management capability
- additional forensic testing to improve our condition ratings and asset data.

Our Opex forecasts are discussed further in Chapters 9 and 11.

Refinements to our planned expenditure

Our expenditure forecasts have been developed with a focus on ensuring we have a network that is positioned to meet the needs of Whangārei and Kaipara communities, now and in the future.

This increase in investment will initially put some upward pressure on prices. However, in the longer term, price pressure will reduce as we implement new solutions to help us

manage the network at a lower cost. Ultimately, the costs of reactive maintenance, repairs, and unplanned renewals would result in less optimal expenditure and larger future price increases than if we smooth the investment requirements over time (as we plan to do).

Our 10-year expenditure forecast is based on current information and analysis of asset health, demand growth, and estimates of the rate of uptake of new technologies. We will continue to update our thinking on assumptions and our planning more generally over time. We consider this to be consistent with good asset management planning practice as well as in the long-term interest of our consumer owners.

Improving our capability

Our people play a critical role in managing our electricity network and are essential to everything we do. Managing long-life electricity assets safely and effectively requires a range of specialised and evolving capabilities. This means we need to have the right capabilities (including in emerging areas such as asset analytics), and we need to help our staff learn and adapt as the electricity sector evolves.

To lay the foundations for our future network and to meet the challenges we face, we need to further improve our asset management capability. We believe strong asset management drives efficient delivery, and we're continuing to make that shift. Underpinning all of this has been an active continuous improvement approach. Capability development (e.g. embedding appropriate processes, systems, and techniques in our business) is essential, and we continue to focus on this.

Our asset management capability comes from our people, the tools we use, and the processes we follow. Having enough people with the right skills is essential if we want to be effective stewards of our distribution network.

> We believe strong asset management drives efficient delivery, and we're continuing to make that shift.

In the coming years, effective workforce planning and competency training will become more critical, as older and experienced staff retire and are no longer available for on-the-job training. For this reason, we are placing an increasing focus on formal competency planning.

AMMAT assessment

Our latest AMMAT maturity assessment (see Chapter 6) has resulted in a lower score than in 2021. This assessment reflects a more robust, systematic review of our full asset management system. This forward-looking review assessed our current capability against best practice asset management and the capabilities required to support:

- our future readiness strategy, including leveraging new technology and innovation
- increased network resilience to meet the challenges of climate change
- improved analytics to support increasing renewal needs.

The gaps identified during this review have been included in improvement initiatives planned or already underway.

Continuous improvement programme

As we deploy new technologies and increase our asset management capability, we need to make sure we foster an appropriate learning environment. We need to identify and embed the right capabilities so we can deliver innovative solutions. This will be especially important as we ramp up expenditure to ensure the ongoing safe and reliable operation of the network and make our network future-ready so we can efficiently support our customers' energy choices.

Recognising opportunities for improvement in our approach and the challenges we, and the wider electricity distribution face, we have developed a continuous improvement programme. Our planned improvements will support increased efficiency and are directed towards aspects of our systems and processes that can deliver the most benefits.

The increasing use of DER, new energy technologies, and the importance of data analytics will have far-reaching implications for how we operate. The mix of required capabilities will change, and it is important that we identify and embed these so we can continue to deliver an efficient service to our customer owners.

> Our continuous improvement program will support the delivery of our commitments to our customer owners.

The linkages between improvement initiatives and better performance or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives will be gradual, noting that many of them will take several years to fully implement. Ultimately, the aim of our continuous improvement programme is to support the delivery of our commitments to our customer owners.

Chapter content

1 Introduction

1. INTRODUCTION

This chapter introduces Northpower's 2023 Asset Management Plan (AMP). It explains its purpose and how it addresses the Commerce Commission's information disclosure requirements. Lastly, it explains the structure of the AMP so that readers can quickly find the information they are interested in.

1.1. Purpose of the AMP

This AMP sets out our over-arching strategy for managing our electricity network. It explains the asset management approaches we use, including asset management principles, forecasting techniques, and the day-to-day practices we use to ensure our assets continue to provide a safe and reliable service to customers. We hope that it will help stakeholders to better understand our approach to managing our electricity network assets.

1.1.1. Period covered by the 2023 AMP

The AMP looks ahead to the next 10 years, from 1 April 2023 to 31 March 2033.

The earlier years of the AMP are based on more detailed analysis of demand forecasts and asset information, resulting in greater levels of certainty. The greatest certainty of projects will be over the next financial year. Beyond five years, while our forecasts and project schedules provide a firm indication of our plans, a degree of change and refinement is anticipated as we respond to the changing needs of our customers and the performance of our assets.

1.1.2. Objectives of the AMP

Our AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. A reference of how it meets the detailed regulatory information disclosure requirements is included in Appendix E. In addition to these requirements, we have developed our AMP to explain to stakeholders our approach to managing our electricity distribution network.

The AMP was approved by our Board on 29 March 2023.

Our AMP seeks to provide our stakeholders with a view of how we develop and operate our network for the good of our community. It sets out our commitment to responsible stewardship of intergenerational assets and how we will prepare our network for the future energy needs of our customer.

To achieve these aims, we have developed a set of objectives to guide the development of our AMP. These objectives include the following:

- setting out our commitment to minimising safety risks on our network
- explaining how we reflect stakeholder needs in our corporate objectives and how these inform our asset management approach
- explaining our risk management approach and the systematic processes in place to mitigate risks inherent in electricity networks
- providing visibility of our investment plans to stakeholders
- setting out our performance targets and explaining how we plan to meet them
- highlighting our approach to managing our assets by providing accessible descriptions and explanations of our approach
- summarising our asset management document suite, showing how these are aligned with corporate goals and setting out our work plans for the planning period
- demonstrating the 'line of sight' between the objectives of the AMP, our corporate goals, business planning processes, and investment plans
- updating stakeholders on improvements to our asset management practices.

Over time we strive to improve our AMP by reflecting on customer insights, considering shifts in external factors, and incorporating advances in new technology and practices to enhance outcomes for our customers.

1.2. Structure of the AMP

The remainder of this document is structured as follows.

Table 1.1: Document Structure

CHAPTER		DESCRIPTION
	Executive summary	Summarises the key points of the AMP
1	**Introduction**	This chapter
2	**Background**	Sets out relevant context for our 2023 AMP
3	**Network overview**	Describes our network across Northland and sets out key statistics
4	**Strategic context**	Explains how we ensure our investments support the needs of stakeholders
5	**Our performance**	Outlines how our network is performing and initiatives we have in place to improve performance
6	**Approach to asset management**	Explains our overall approach to asset management, including assessments of our capability
7	**Risk management**	Explains our risk management approach, outlines our key risks and how we manage them
8	**Network development**	How we address demand growth, security of supply, and connect new customers
9	**Asset lifecycle management**	How we manage our existing asset fleet, key issues, and current network condition
10	**Supporting activities**	Overview of the activities that support our asset management
11	**Summary of Expenditure Forecasts**	Sets out our planned investments over the AMP planning period
APPENDICES		**DESCRIPTION**
A	**Glossary**	Sets out the meaning of acronyms and technical terms
B	**Disclosure schedules**	AMP disclosure schedules required by Commerce Commission
C	**Further network details**	Detail of our network feeders and substations. This includes details on our larger network investments over the AMP period
D	**Further risk information**	Provides further detail on the network risks, and how we manage them
E	**Disclosure requirements**	Sets out how the AMP addresses Information Disclosure requirements
F	**Director's Certificate**	A copy of the AMP's director certification

Chapter content

2 Background

2. BACKGROUND

2.1. Introduction

Northpower provides residential and business customers with a safe and reliable electricity distribution service. Our networks span the Whangārei and Kaipara districts and provide the physical link between the national grid[3] and our customers' homes and premises.

Our customers are also our owners – every customer connected to our network is an owner represented by the Northpower Electric Power Trust. Trustees are elected by the community and represent the customers by defining the desired outcomes to be achieved by Northpower on behalf of our consumers. The trust engages with the board of directors on long-term matters affecting Northpower's business strategy.

In this chapter, we discuss the overarching context for our 2023 AMP and how this has impacted our approach to asset management. The wider environment we operate in is an important factor in how we deliver our services. Factors such as the evolving energy market and the increasing impacts of climate change mean we need to continually improve our underlying capabilities.

Reflecting our efforts to improve our asset management approaches, this 2023 AMP has been significantly revised and expanded from previous versions. In particular, we include expanded discussion and supporting information on our future investment plans.

Getting closer to our customers is an underpinning theme of this AMP. Our aim is to better understand the views of our customers and stakeholders so we can evolve our services to best meet their changing needs. In this chapter we outline how we engage with our customers and incorporate their views in our decision-making.

We also provide an overview of our strategy to evolve our electricity network so that it will meet the future needs of our customers and facilitate their energy choices.

2.2. Overview of Northpower

As an electricity distribution business (EDB), Northpower provides residential and business customers a safe and reliable electricity distribution service. The key activities we undertake to deliver this important service include:

- maintaining assets to ensure they are safe, secure, and provide reliable service
- building new assets and upgrading existing capacity as our region grows
- replacing assets as they reach the end of their service life
- managing our network in real time, to ensure its effective operation and the safety of those interacting with our network
- connecting new customers to the network
- enabling renewables generation and new technology to be connected to our network.

[3] Owned and operated by Transpower.

2.2.1. Proudly trust owned

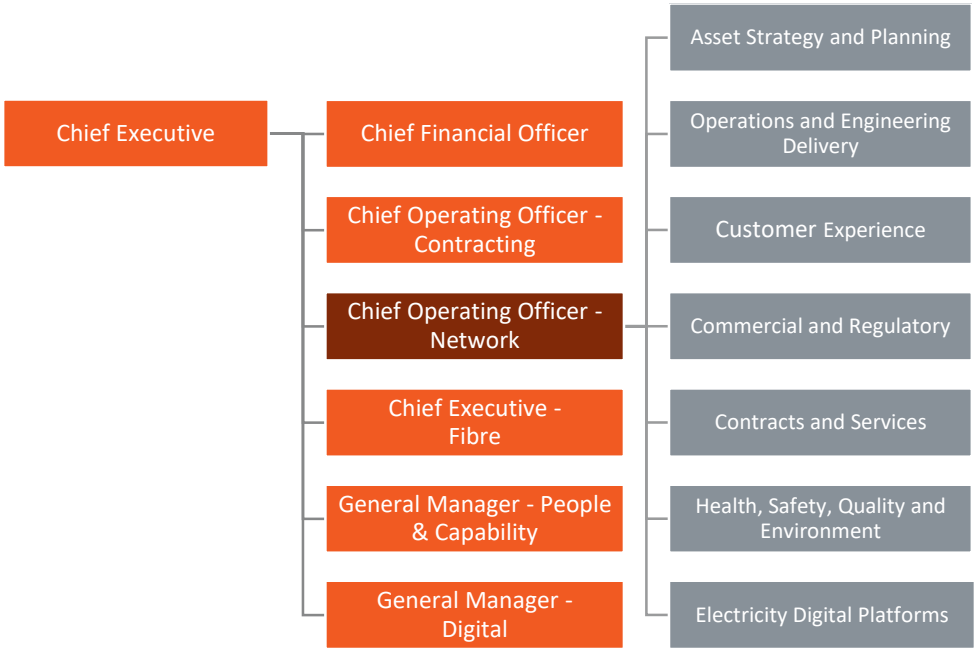
Our customers are also our owners – every customer connected to our network is an owner represented by the Northpower Electric Power Trust. The trust represents the consumer owners of Northpower.

Trustees are elected by the community and represent the customers by defining the desired outcomes to be achieved by Northpower on behalf of our consumers. It appoints Northpower's directors and sets the expectations for the performance of the organisation. The trust engages with the board on long-term matters affecting Northpower's business strategy.

2.2.2. Our structure

Within Northpower, the network division is responsible for the electricity-related asset management functions. As depicted below, the chief operating officer (COO) - network leads a set of functional teams to perform this role.

Figure 2.1: Electricity network division within our organisation structure



The COO – network is accountable to the chief executive for meeting the network operational and financial targets as set out in our statement of corporate intent. The COO – network oversees seven teams that manage the following areas and responsibilities.

- **Asset strategy and planning**: this team is responsible for developing asset strategy, asset replacement planning, asset information, and network development. It also has responsibility for development of our asset management plans, systems, and frameworks.
- **Operations and engineering**: this team is responsible for engineering design, project delivery, maintenance delivery, and network operations.

- **Customer experience**: team is responsible for core customer services, including helping customers get connected to the network, enabling distributed generation, and all consumer engagement, including ensuring we understand consumers' needs and deliver to meet those needs.
- **Commercial and regulatory**: team is responsible for managing our relationships with regulators and retailers, and setting our pricing and commercial direction.
- **Network contracts and services**: this team is responsible for managing our relationships with our approved network contractors and other external parties that provide services to support the network.
- **Health, safety, quality, and environment (HSQE)**: this team is responsible for developing and delivering HSQE frameworks.
- **Electricity digital platforms**: this team manages and develops the electricity digital platforms used to support the electricity network.

Shared services functions, which sit across the other divisions, support our electricity business by providing specialised capabilities, management and assurance functions, processes, and systems. These functions include:

- **commercial, finance, legal and risk**: provides legal support and sets the enterprise risk management approach. Responsible for corporate financial functions and strategy processes
- **people and capability**: manages recruitment, onboarding, remuneration, learning and development, staff well-being, and group communications
- **digital**: provides enterprise digital support through provision of underlying digital infrastructure, security services, and enterprise digital and data systems.

2.2.3. The communities we serve

Northpower provides a safe and reliable electricity distribution service to residential and business customers across the Whangārei and Kaipara districts, comprising:

- 100,500 population in the Whangarei district
- 24,100 population in the Kaipara district.

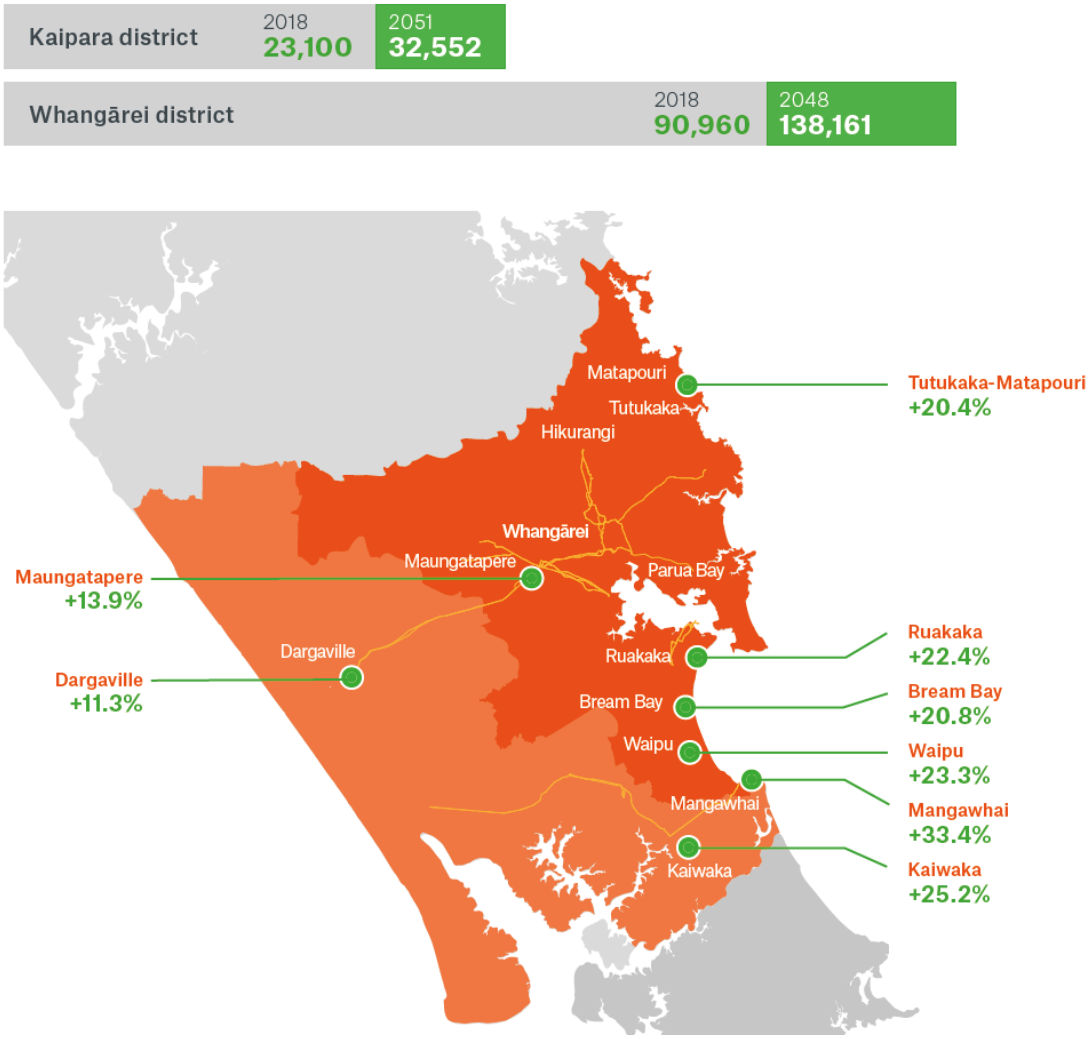
These districts showed some of the highest growth rates in New Zealand in the 2018 census. Increased migration to the regions has been a key contributing factor as housing affordability continues to be a major issue in New Zealand.

In the past three years we have added 2,660 new customer connections to our network. Development along the coastal regions, in particular Tutukaka/Matapouri, Marsden Cove, Waipu, and Mangawhai continue to attract new subdivisions and businesses requiring additional supporting infrastructure.

Whangārei is the only city in Northland, as well as its major service centre. Primary industry is the largest employer of the rural sector in Northland (agriculture, fishing, and forestry). We recognise the importance of gaining a deeper understanding of the customers and communities we serve, especially as our region changes and evolves. This is a core part of our strategy. We carefully plan investment in our network to ensure we continue to

provide resilient and reliable infrastructure that supports our communities and the future growth of Northland.

Figure 2.2: Population growth and population projections for Kaipara and Whangārei districts[4]



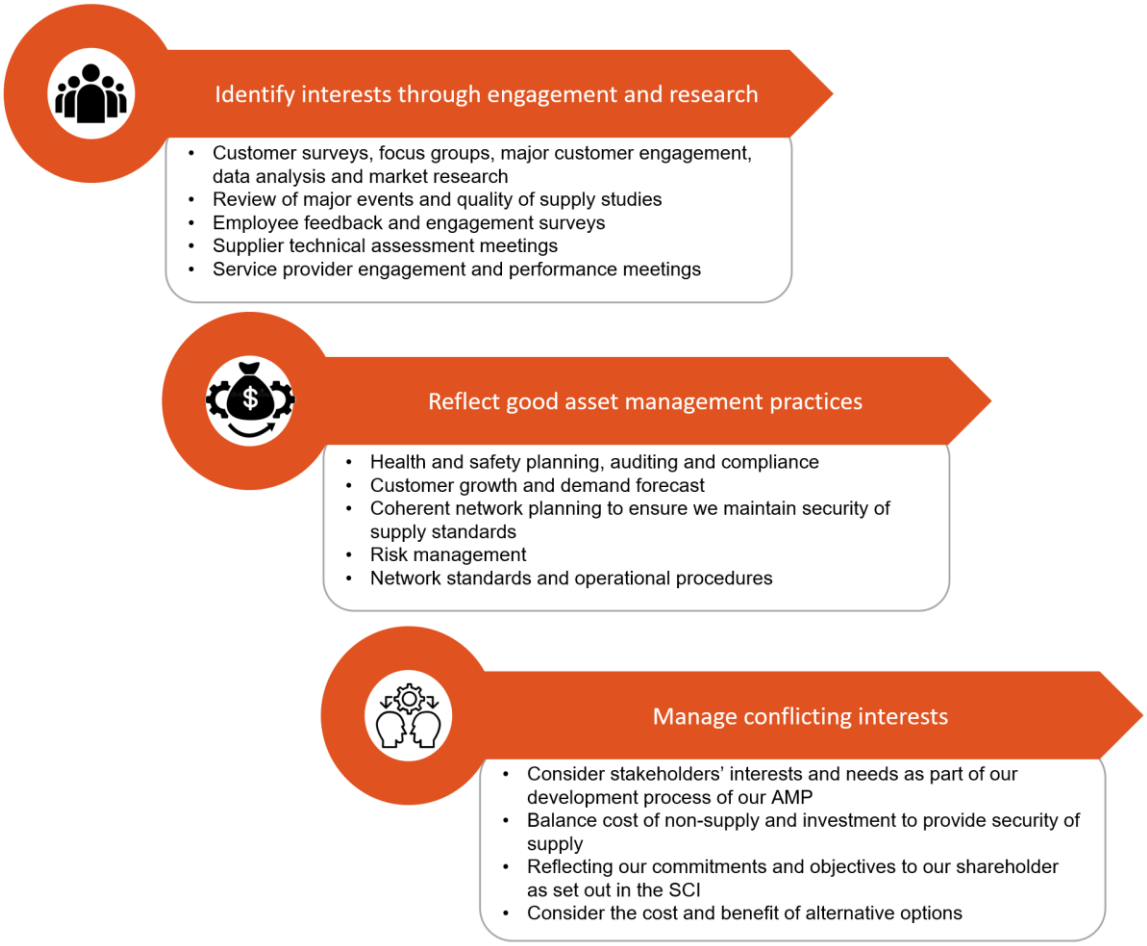
Against this backdrop of growth and migration, our inland communities continue to fuel our local economy via horticulture and agriculture, with the Whangārei district adding marine services, manufacturing, and processing industries. As the mix of industries continues to develop, longer term prospects for the region remain positive.

2.2.4. Managing stakeholder interests

We understand the importance of appropriate stakeholder consultation (see Section 3.4.6) to ensure proper coordination, dissemination of information, and maintenance of good relationships. Figure 2.3 shows how we manage stakeholder interests, including where there are conflicting objectives.

[4] Growth figures compare 2013 and 2018 census results.

Figure 2.3: Understanding and managing stakeholder interests



2.2.5. Staff engagement

Effective staff communication involves clear, timely, and relevant messaging between senior management, team leaders, and our field staff. It helps us embed effective asset management across our business.

Clear communication helps avoid misunderstandings and errors, which is essential when worker and public safety might be compromised. Staff are more productive, with better job satisfaction, when they have access to the information they need to do their jobs well.

Examples of our asset management communications include:

- engagement and feedback while developing our AMP
- publishing asset management material and information on our intranet
- internal presentations and updates on our works plan for network and contracting teams
- leadership communications and presentations
- internal monthly updates on asset management issues
- formal and informal learning sessions.

If our people are well informed, they can make better decisions. This will be increasingly important as we look to increase our asset management capability in the coming years. Ultimately, effective communication provides the information needed to make informed decisions, leading to better outcomes for all our stakeholders.

2.2.6. Field services

Northpower's in-house contracting division is the primary field service provider operating on the Northpower network. The network contracts and services manager administers the interface with the contracting division under a defined governance structure, underpinned by a service level agreement (SLA). The schedules to the SLA have defined task-based activities determining scope, resources, and time required to complete the activities. This provides the ability to benchmark performance and improve efficiency.

Northpower Contracting is one of the largest electricity distribution contractors in the North Island, giving our electricity business access to a wide breadth of capability, a large and mobile workforce should additional resources be required, and extensive purchasing power for subcontractors and materials. One advantage of this arrangement is better alignment between our planning and delivery functions, ensuring consistent approaches, standards, and operating practices.

To ensure sufficient delivery capability, large value capital works may be subject to competitive tender. This also facilitates benchmarking of our delivery function against the wider market. External contractors and the internal contracting division are subject to the same health, safety, quality, and environmental management policies and standards as the wider company and must be authorised to work on the Northpower network. This includes field audits to ensure the work has been completed to required standards.

2.3. Context for our 2023 asset management plan

In this section we discuss the context informing our 2023 AMP and how this has influenced our planned investments over the 10-year AMP planning period.

2.3.1. Addressing our ageing network

As we improve our condition monitoring, asset information, and analytical capability, we recognise a growing need to increase the rate of asset renewal on our network. As our assets continue to age their condition continues to deteriorate, increasing the risk of asset failure. The detailed planning and analysis we have undertaken to support our AMP investment plans shows a need to lift renewal expenditure in some of our asset portfolios. This is necessary due to the large portion of assets that continue to degrade. If this is not addressed, they will begin to pose unacceptable levels of risk and could adversely impact supply.

Managing network and safety risks

Elevated safety risk is one potential consequence of poor asset health and is often accompanied by others, such as reliability risk, environmental damage, and non-compliance. Public safety risk is greatest for asset classes in close proximity to people,

particularly overhead line assets. Safety risk to workers extends to assets in our substations and increases with deterioration of asset health. These issues are discussed further in Chapter 7.

As a lifeline utility, it is critical that we invest prudently to ensure our assets are safe, reliable, and resilient in the longer term. This involves carefully managing our asset portfolios to ensure stable condition and performance to effectively manage network and safety risk.

Improvements to our renewals planning

To effectively manage risk on our network, we need to ensure our work programmes prioritise those assets that pose the greatest risk. This needs to be driven by robust and accurate needs identification, underpinned by good practice analysis that utilises comprehensive, robust asset information.

We have made a number of improvements to our renewals forecasting approach, including:

- overhauled intervention strategies
- refreshed asset information
- improved analytical techniques and modelling
- accounted for expected delivery efficiencies that will lower overall cost
- used external specialist consultants to review and test our modelling.

Over time we will augment our improved analytical capability with improved and expanded inspections and testing to better understand asset condition and related risk.

Implications of our planned investments

In our overhead line fleets (with the exception of the poles fleet, due to the historical investment in concrete poles) we are forecasting an increasing level of risk of asset failure. Based on an improved understanding of overhead asset condition we have established larger conductor and crossarm replacement programmes. There are significant volumes of assets with (modelled) deteriorating health in these portfolios, indicating an increasingly large number of end-of-life assets. Addressing these issues requires targeted investment to reduce the risk of assets failing in service.

Key benefits of our proposed renewal investments include:

- **Keeping our networks safe**: modelling suggests that increasing asset-failure risk requires increased investment levels in several asset portfolios to reduce the safety risk posed by failure of these assets.
- **Manage asset health**: ensure asset health is stable through proactive renewal, focusing on assets in poor condition and using criticality for prioritisation. This approach will help prevent asset failure and reduce the need for less cost-effective reactive repairs and replacement.
- **Prudent defect management**: ensure we do not accumulate replacement 'backlogs' by addressing the increasing number of ageing assets. It is important that we maintain sustainable (steady state) volumes of work and address risk through a proactive programme.

- **Deliver a reliable service**: as the AMP period progresses, we expect to increase our focus on ensuring that customers receive their preferred levels of service. An important aspect of this will be successfully meeting our reliability targets, which we have aligned with the DPP regime. Investments we make to address the risk of asset failure will (over the medium term) lead to improvement in our reliability performance.

Delivering a safe, secure, and reliable service into the future requires that we invest more in the network. We have committed $718 million over the next 10 years to this purpose. The cost of building and maintaining electricity distribution supply infrastructure is recovered through the line charge component of consumers' electricity bills. Ultimately those costs are passed on to customers through increased line charges on their power bills.

All things being equal, increased investment places upward pressure on prices, and we are working hard to minimise this cost impact on customers. Given concerns around affordability for our consumer owners, we have sought to minimise, where prudent, our 10-year expenditure through rigorous review and challenge. This ensures our planned projects and programmes are appropriate and that we have deferred expenditure where possible.

2.3.2. Evolving energy market

The New Zealand energy market, like many overseas, is seeing the emergence of new renewable energy supply options (such as rooftop solar), new applications for electricity (such as electric cars), and new methods of storing electricity (such as in-home battery systems). These developments are complementary to current energy market arrangements. Such developments herald a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use.

To act as a foundation for future energy markets, our network should not limit customers' options to adopt technologies such as rooftop solar generation and electric vehicles.

We are committed to facilitating the integration of new energy solutions. We firmly believe that our network is a key community platform to support this. We are preparing for this future in a number of ways, including:

- lifting investment in our electricity network to ensure it continues to provide secure and reliable service while accommodating growth in our region and supporting integration of new energy solutions
- refining the way we charge our customers to ensure the charges we impose are reflective of actual cost, and ensuring equitable and fair charges as new energy solutions emerge
- improving how we work with customers by streamlining and modernising our communication tools and taking an active stake in understanding, enabling, and providing advice on new energy options.
- making targeted, least regret investments in enabling technology.

The objectives and investment plans within this AMP reflect this balanced focus on network safety, reliability, enabling future energy choices, and maintaining high levels of customer satisfaction.

Our focus on future technology will increase over the AMP period

Over the coming years we plan to increase our focus on future technology to allow research and development, and testing of new and innovative network and non-network solutions. With increased efforts to promote decarbonisation, we expect to see more electric vehicles, photovoltaic installations, and battery storage systems installed on our network. We believe it is prudent to prepare for increased uptake of these resources now, rather than react at a later stage.

2.3.3. Responding to climate change

Climate change is a global issue that requires significant and immediate action. The global climate is changing at unprecedented levels and the main driver for this is an increase in greenhouse gas emissions from human activities. The term 'climate change' refers to the change of weather patterns over an extended period of time.

Potential impacts

The impacts of this changing climate will bring significant direct and indirect changes and challenges. These include a growing frequency of extreme weather events, more prolonged dry periods, ground movement due to higher levels of rain, rising sea levels, and increased coastal flooding and erosion. The impact and frequency of these events will increase over time as climate change continues to accelerate.

In New Zealand, potential impacts of climate change are likely to include:

- higher average temperatures
- extreme rainfall events
- more severe storms with higher wind speeds
- droughts will become more common and more severe, leading to fire risk
- communities and infrastructure assets near the coast will be increasingly vulnerable to sea level rise
- more ground instability due to high rainfall events
- storm events combined with sea level rise will increase the likelihood of river flooding and coastal inundation.

Over the 10-year AMP planning period we expect to see further evidence of the above impacts and will need to respond accordingly.

How we are responding

We are beginning a journey of climate understanding, response, mitigation, and adaptation. Our aim is to operate a low-carbon organisation that is resilient to climate impacts. This means engaging our people on the issues and assessing the vulnerabilities of our assets and services in a changing climate.

There is a large amount of uncertainty in the development of climate change adaptation strategies. This includes incomplete data sets on which to base decisions and a significantly changing landscape. We will need an adaptive approach that specifies actions to be taken immediately, and those required to adapt in the future if needed in light of tipping points and

triggers. To ensure our response to climate change is flexible, effective, and responsive to the unpredictable environment, regular reviews will take place. These reviews will consider:

- central government legislation
- views of the wider electricity industry, both in New Zealand and overseas
- local government's plans and strategies
- changing Northpower priorities and needs of our customers.

A periodic scan of these changing factors will be used to provide direction and insight over the AMP period.

We need to act now, even with uncertainty. This means acting now on 'no regret' measures that can be implemented without knowing the full impact of future climate change. We will identify areas within our control (e.g. substation locations) and external factors we can influence (e.g. choices by third-party developers) to find mechanisms for addressing these. We are beginning by:

- **decision-making**: factoring climate change into decision-making and operationalise it to become business as usual. We will consider medium- and long-term climate change in relevant investment and planning decisions
- **mitigation**: pursuing climate change mitigation strategies, including reducing our greenhouse gas emissions on an ongoing basis
- **adaptation**: developing strategies and approaches to ensure our assets and operations are resilient to the impacts of climate change
- **evolving strategy**: evolving our strategies as more certainty is gained on the impacts of climate change and the effectiveness of actions to adapt and mitigate
- **agile work programmes**: adopting agile project management with flexibility and innovation – this will be most suitable when addressing climate change
- **engagement**: seeking inputs from all parties impacted by climate change, including mana whenua and Northland communities.

This is not a challenge we can face on our own. We have joined with the ENA, EEA, and Northland Lifelines Group to work collaboratively on these issues. We also work with district and regional councils at planning and operational levels to ensure that we take into account the latest information when carrying out our activities.

Our response to climate change fits under our environment focus area (see Chapter 4). We discuss our broader approach to resilience and risk management in Chapter 7.

2.3.4. Improving our asset management capability

Recognising the challenges and opportunities presented by our ageing assets, climate change, population growth, and the evolving energy landscape, we are continuing to focus on improving our asset management maturity and approach. This work has already made good progress, and the analysis set out in this AMP illustrates some of the advances we have made.

As discussed in Chapter 6, we are committed to further developing our overall asset management capability to ensure we meet accepted best practice standards. This will require investments in our people's capability and our supporting systems.

To guide our progress, we have undertaken a detailed review of our asset management capability as part of our AMMAT[5] review. This robust review of current capability has been informed by external advice and the views of new staff who bring valuable experience from other New Zealand EDBs. This assessment (discussed in Chapter 6) resulted in a score of 2.0 (out of 4). This is a reduction compared with our 2021 score. Our latest score reflects our evolving view of good practice and the need for EDBs to continuously improve, given the challenges discussed above. Our aim is to be open and transparent about our capability. We plan to put in place a series of initiatives to lift our maturity over the coming years.

Over the planning period we will focus on improving staff competency, developing fit-for-purpose systems, and adopting proven innovations. This includes further improvements to our risk management approach, largely based on refining our asset health modelling and embedding a network-wide criticality framework. These initiatives will enable targeted interventions and better inform our renewal forecasts over the planning period.

Our ultimate aim is to ensure our asset management is consistent with good practice within five years. We have adopted a target to achieve an AMMAT score of 3 or greater by 2025. This reflects a commitment to further improving our overall asset management capability to ensure we can cost effectively meet the needs of customers. We will invest in the capability of our people and ensure that our systems, supporting data, and processes effectively enable our wider work programmes.

2.4. Customer engagement

In addition to operating and maintaining our network, ensuring we deliver for our customers requires understanding their needs and aspirations so that we can ensure our service remains relevant to them.

We are furthering our investment in our customer experience team to improve customer service. Our customer relationship management (CRM) system helps us to keep track of all interactions and requests, ensuring we meet our commitments to our customers.

2.4.1. What our customers have told us

We engage with customers through a range of channels and actively consult with them. We seek out customer views on future investment plans – what matters most to them and their experience in dealing with us. Our dedicated customer experience team focuses on putting customers at the heart of all we do. As depicted below, customer views and feedback are incorporated into our decision-making through regular surveys, market research, and engagement with special interest and community groups, direct consultation, and ongoing customer feedback.

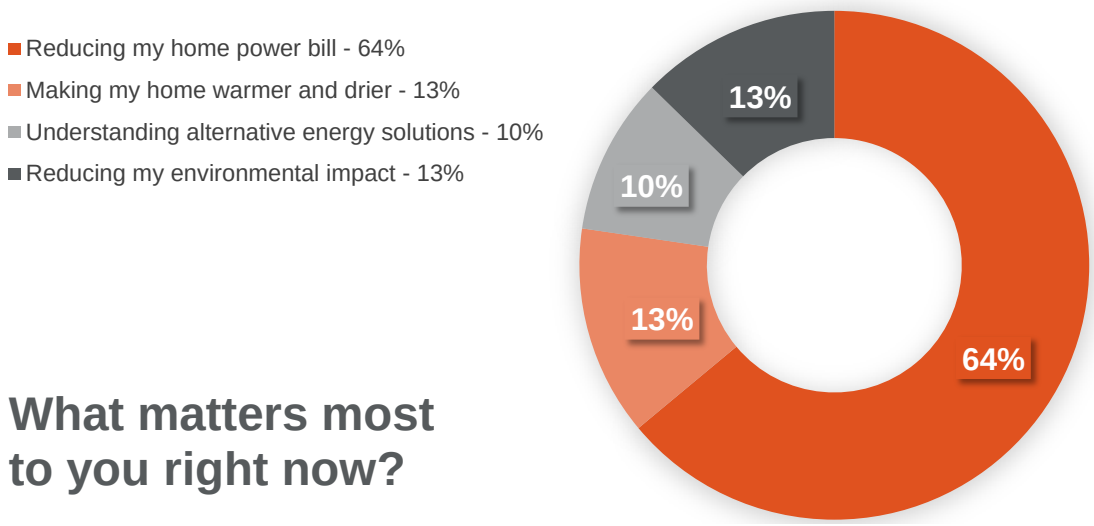
[5] AMMAT refers to the asset management maturity assessment tool which is an information disclosure requirement that needs to be prepared and included in our AMP.

Figure 2.4: Northpower's customer engagement model

An example of this is our in-person community survey, undertaken during the 2021/22 summer. This type of engagement is increasingly important given the significant changes taking place in the energy market and with energy hardship a growing issue in the region. The increasing adoption of new solutions such as electric vehicles and solar power by consumers are changing the way our customers use energy. We see it as part of our role to understand our customers' needs and support our community in ways that are meaningful to them. As part of this survey:

- we received 2,207 responses to the survey (1,837 online and 270 in person)
- 270 were considering changing energy retailers
- 231 home energy assessments
- 100 requests for advice and information on EVs and solar.

Figure 2.5: Key results from our March 2022 survey



Our customer survey was undertaken in response to the significant changes in the energy market, with energy hardship a growing issue, and new technologies poised to change the way people consume energy.

Our survey asked customers to identify what mattered to them most from these four options:

- reducing their power bill
- making their home warmer and drier
- understanding alternative energies like solar and electric vehicles
- reducing their environmental impact.

The survey revealed energy hardship as a significant problem for families. A total of 64% of customers would like to reduce their monthly bills, while 45% of that group said they struggled to pay their bills each month.

Our survey highlighted energy literacy opportunities to help customers cut their energy costs. According to our survey, 36% of people did not know they could save money by switching off appliances that are on standby, while 32% did not know switching to LED bulbs could save them $10 a month on average.

Around a quarter of customers were interested in learning more about solar power and electric vehicles and taking a more environmentally conscious approach to energy usage.

The survey supports a wider project to ensure we can adapt to meet the needs of customers in a rapidly evolving energy market. This has shaped our communication strategies and directed our focus on to our consumers' main areas of concern. These findings will inform our future strategies and guide our focus as we engage with customers on new energy technologies and energy efficiency education, and provide advice on reducing energy costs. We see a role for us in helping our customers get the most from their energy choices to help them drive down the total cost for their energy.

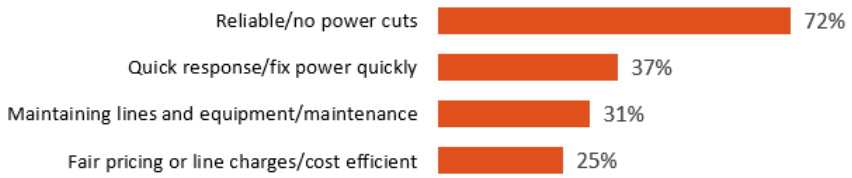
2.4.2. Customers' top priorities

Our customers are consistent on what matters to them most. Our customers continue to rate reliability as their highest priority. Responsiveness (quick restoration of power) is also highly important. They recognise that an investment in maintaining the lines is important to achieve this, but want to ensure we balance this with being cost-efficient so that pricing remains fair. They've told us their key priorities are:

Figure 2.6: Customers' top priorities

These priorities are fundamental to how we manage and operate our network.

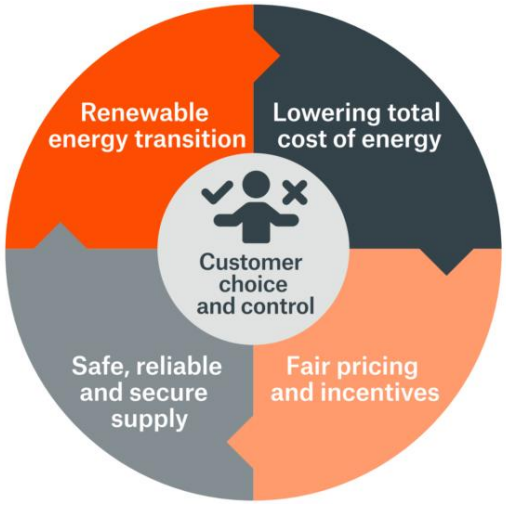
Figure 2.7: Top priorities as identified in annual customer survey, March 2022



2.4.3. Supporting customer choice

Customers have told us that ensuring the network is able to manage their future energy needs and choices is important. We are investing and preparing for expected changes to ensure our network is resilient and able to cope with these changes, while ensuring pricing remains fair.

Figure 2.8: Our approach to supporting our customers' energy choices



Reflecting the above approach, we take a balanced approach to supporting our customers' energy choices, acknowledging we need to balance the following outcomes:

- customer choice and control
- clean energy transition
- safe, reliable, and secure electricity supply
- lowering total cost of energy
- fairness and incentives in our network pricing.

2.4.4. 'Always on' customer contact centre

Our customer experience and network operations teams provide a 24/7 customer contact centre. We talk to around 3,500 customers per month over the phone and in person. We are also available through social media channels, where approximately 4,500 customers per month engage with us.

While responding to requests and helping customers get the information they require, we can keep track of key trends and concerns through our customer relationship management

(CRM) system. Reviewing these trends helps us identify and improve our processes. Monthly surveys are completed, where customers who have interacted with us (during faults or customer initiated projects) are called and asked for ratings and feedback. This feedback is considered to further enhance our service.

2.4.5. Customer engagement on major projects

Customers affected by major projects are consulted and their views are taken on board during the project planning phase. Changes to planning dates or other mitigations may be considered and provided where appropriate.

Over the last five years, we have worked on several substation upgrade projects. These projects have involved heavy machinery, earthworks, and the installation of new transformers. Neighbours living or working close to Hikurangi, Ngunguru, Parua Bay, Kaiwaka, and Ruawai substations have been consulted and included in the planning phases of our projects. We have worked with these stakeholders to ensure that they were aware of the work happening and that the disruption caused was as minimal as possible.

Before the recent build of Maunu substation, we invited local iwi and all neighbouring property owners to an information sharing event and sod turning. When the project was finished, all stakeholders, neighbours, and the public were invited to come and tour the new substation. This was a valuable learning exercise for our team who were able to better understand customers' views and questions.

2.4.6. New connections

One of our customer centre's main goals is to make it easy for customers to connect to our network or to upgrade, and to change their connection to solar energy at any time. Our main principle is to guide customers through what can seem a daunting process, make it easy and straightforward, and to be fully transparent about any issues, helping customers and their electricians to work through these.

Our CRM system is used to record these interactions with customers, and customers can use our portal (see links below) to request required services. This portal walks customers through the application process, guiding them to find information, and submits the application to our customer team.

The application is reviewed by our dedicated customer technical team. Once the connection is approved the team coordinate with the retailer and livening contractor to connect the customer.

Connection time frames

Our target for service is five working days between submission and our approval. This is achieved for over 80% of applications. After our approval, the livening process time frame is dependent on retailer approval, ordering of metering, and availability of the contractor to inspect and liven. If power is already available at the boundary the livening contractor will usually have the connection live 10 working days from receiving our order and approval from the retailer.

For those that require additional work or where we identify complexities, our technical team makes contact with the customer or electrician to advise what may be required and help them solve this. One commonly encountered issue is the need for power to the boundary to be made available. This can require engineering and design input as well as construction work. The required time frames will depend on the complexity of these works.

For those customers wanting to change their connection to import/export metering to enable solar, it is usually straightforward. Customers in rural areas or on long service lines may need to overcome voltage drop issues or reduce export to manage this.

Larger or new industrial connections can take some time to design and to reach agreement with the customer on commercial arrangements. The time frame for these is also dependent on other external factors, including procurement of required equipment and work scheduling.

Box 2.1: Connections information

Information for customers wanting to connect to Northpower's network is on our website here.

Information for generation customers, both small and large scale is on our website here.

2.4.7. Stakeholder engagement

We have recently enabled a wider range of approved contractors to undertake customer connections to the network. This has resulted in positive change for our stakeholders and customers, providing customers with a choice and new business opportunities for stakeholders.

Monthly customer surveys

We engage an independent customer research agency to carry out monthly surveys of all customers who have had contact with us in the prior month – either a new connection, customer-initiated works, or a fault response. Customer satisfaction is measured across key touchpoints and verbatim comments are reported along with net promoter score and satisfaction results. Feedback is reviewed by customer and operations staff and performance scores are reported to the board monthly. Changes are made when required to ensure continual improvement.

Annual survey

An annual survey of 400 customers (both commercial and residential) across the region is undertaken by an independent research company. Customers are called and invited to give their views on a range of questions, around what is most important to them and how we are doing in those areas. The results of this survey are discussed in Section 3.4.1 and Section 5.3.

Direct engagement

Ongoing meetings with key stakeholders in the new connections area, such as electricians, builders, developers, and community groups, help us understand what is important to them and how we can improve our service.

A new technical advisory group has been formed. This is a representative group of community electricians, solar installers, and inspectors in the Northland region that meets around four times a year. The aim of the group is to inform, discuss, and advise Northpower about proposed changes, new energy developments, and any improvements Northpower can make around requirements and communications.

The input from this group has been instrumental in directing the changes to our processes and services, and helping us respond to changing requirements with new technology entering our industry.

Our key stakeholder engagement also includes consultation and feedback from our electricity network team, shared services teams, and our contracting partners. This feedback helps prioritise improvement initiatives.

Community outreach

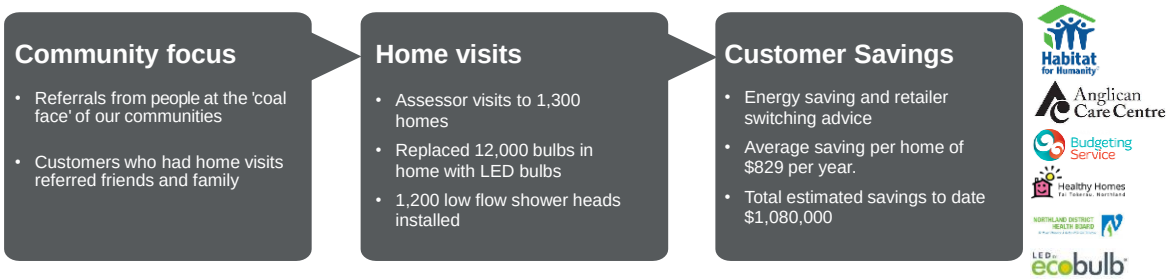
With customer feedback and statistics from our region showing that many of our consumers have difficulty paying their power bills, Northpower put together a consumer outreach programme aimed at helping Northlanders with practical energy-saving advice and assistance to reduce total electricity costs.

We applied for and have been successful in winning funding from MBIE's Support for Energy Education in Communities (SEEC) programme to help fund this work. The SEEC programme is part of a suite of new government initiatives focused on lifting people out of energy hardship.

Working with community partners to reach households in need, we have delivered personalised electricity advice and support to over 1,000 households across the Whangārei and Kaipara districts. This includes practical help through home energy assessments, helping customers find the best retail plan for their needs, and providing free LED lightbulbs and low-flow shower heads.

Over the past 12 months we helped over 1,300 customers find the right retail plan, and over 12,000 light bulbs and 1,200 shower heads were installed. Implementing the energy saving actions and changing retailers gave an average saving per home of $829 per year, saving these customers approximately $1,080,000 in total.

Figure 2.9: Serving our communities – energy education programme

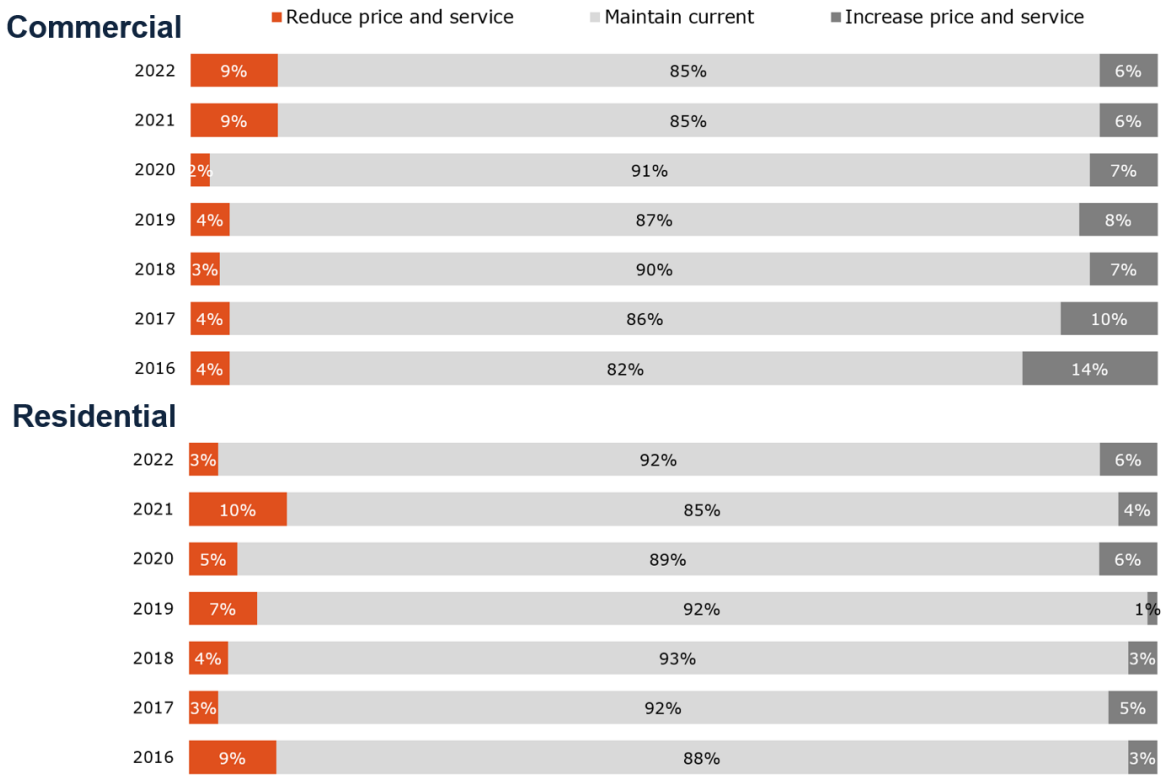


2.4.8. Customers are happy with existing reliability levels

The vast majority of customers indicated in our surveys that they want existing service levels maintained, and these results have been reasonably consistent over the last five

years. This is an important input when determining the level of network investment into reliability associated projects.

Figure 2.10: Preferred level of service, annual customer survey, March 2022

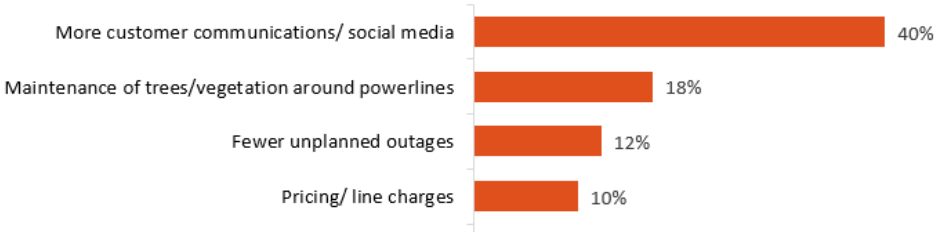


The above responses were received when customers were asked about their preference for Northpower's level of service,[6] noting that changes in service levels might require changes in price. The same proportion of commercial customers preferred to maintain current price and service levels – 85% in both 2021 and 2022. In 2022, there was a higher proportion (92%) of residential customers who are happy to keep current levels of service.

2.4.9. Communication is increasingly important

In the last annual survey, when asked what we could do better, the most common response was a desire to see more customer communications, including the use of social media.

Figure 2.11: Suggestions for improvement, annual customer survey, March 2022



[6] Level of service being based on reliability of supply, supply quality, and response times to faults.

The customer feedback we receive reinforces the increasing expectations of real-time information about network outages and planned works. As well as advising customers of planned outages well ahead of time, we publish both planned works and unplanned outages on our website. For large unplanned outages, or events such as storms, we also utilise social media channels like Facebook.

This is becoming a preferred communication channel for many customers and is utilised for updates around network plans, investment news, and outage information sharing, as well as keeping customers engaged.

2.4.10. Outage communications

Planned outages

We directly inform customers of planned outages with at least 10 working days' notice. Retailers are advised at the same time, but we do not rely on retailers to advise our customers. All ICPs that may be impacted by the outage are automatically identified and grouped by network typology. Automated emails advising of the outage are sent at the time of processing, and then 10 days, five days, and the day before as a reminder. Around 85% of our customers have up-to-date email addresses. For those without an email address, a letter is printed at the time of sending and posted to customers.

If an outage is cancelled or changed, this is updated in the system and an automated email is sent to all affected customers instantly.

When work is being planned, large industrial customers, sensitive customers, and essential services are taken into account and, as much as possible, plans are discussed and agreed upon (and often changed to suit) well in advance with these customers.

Details of planned outages and any cancellations are available on our website here.

Unplanned outages

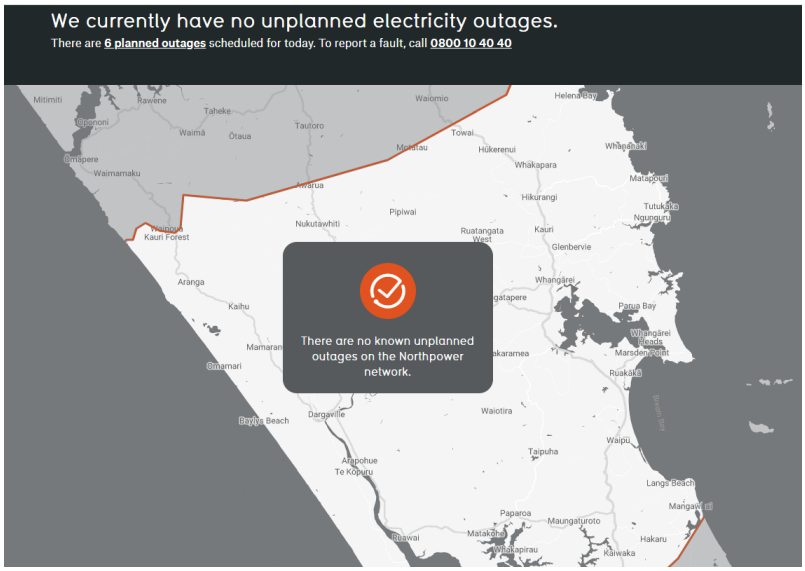
Our 0800 number for faults is the first port of call for most customers experiencing an unplanned outage. Our local team takes calls 24/7 and dispatches fault staff quickly.

The 0800 number has an automated answer message which has a recording of known faults. This can save customers time waiting if the call centre is busy during a large outage.

When there are outages affecting a large number of customers or clusters of outages in a storm event, we post updates on the Northpower Facebook page. We use this page to interact and answer any questions from customers related to that outage.

Our website displays a map showing current unplanned outages and information, including cause and expected time of restoration, as that information becomes available.

Figure 2.12: Example from our outages webpage



2.4.11. Addressing customer complaints

If our customers have a complaint or problem, we want to fix it.

We want to help resolve issues our customers are experiencing. Often a discussion with one of our team is all that is required to resolve concerns. Our local call centre takes calls, emails, and Facebook messages, or feedback from staff, around customer complaints.

Complaints resolution process

We are a member of the utilities disputes scheme. Customers are advised on our phone messaging system for all calls that we are a member of the utilities disputes scheme and that if any complaint they make is not resolved within 20 working days they can call Utilities Disputes. We provide contact information for this scheme on our website. Information about our complaints process is on our website here.

Voltage quality

We take power quality complaints very seriously. We will work closely with customers to identify the issue and find a solution. We continually assess how well our processes address these issues and refine them as opportunities to improve are identified.

Customers can find information about quality issues and report their quality issues by calling our 0800 number, or via a form on our website here.

This is picked up by our dispatch team who send a staff member out to check on the customer's connection or to identify if there is an issue upstream of their connection point. For example, power quality issues are usually due to the distribution transformer tap setting being incorrect, the customer's motor start-up not operating correctly, or voltage rise due to solar penetration. The majority of these issues can be resolved quickly by adjusting the distribution transformer tap setting. Our staff member on site will advise the customer, or our customer team will get in touch to let the customer know the source of the issue and the plan to resolve it.

Chapter content

3 Our Network

3. OUR NETWORK

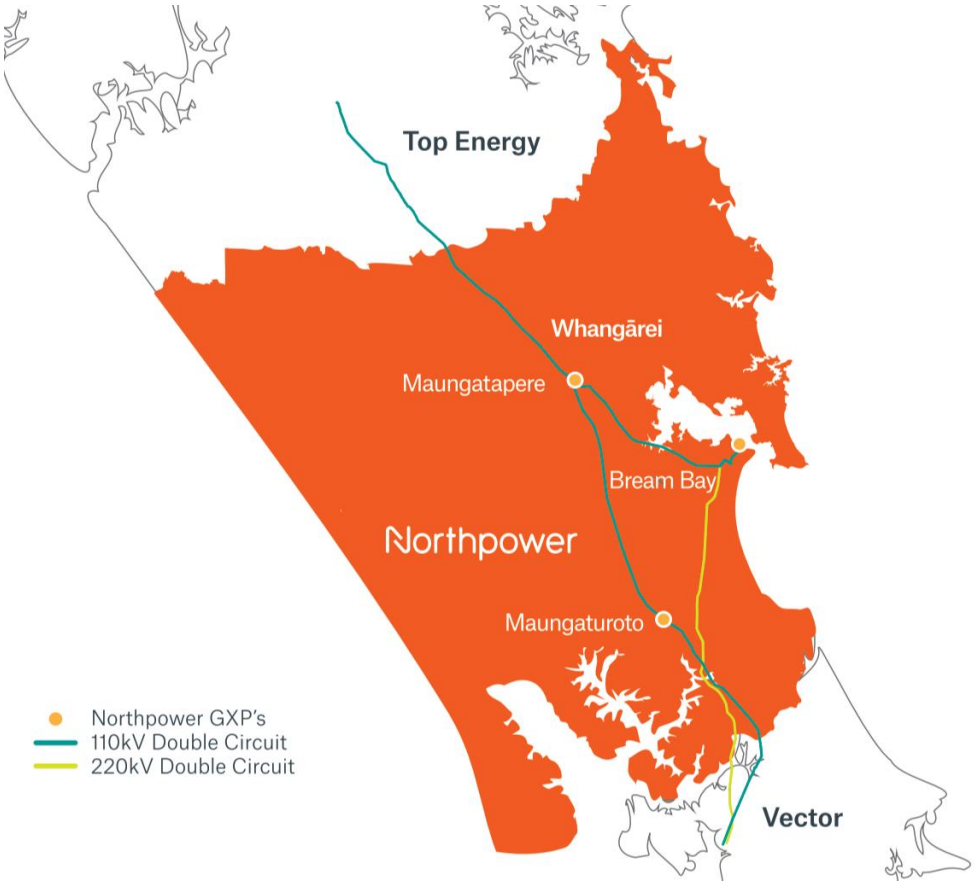
3.1. Introduction

Our electricity network distributes electricity from the Transpower grid to our customers. The network is made up of a number of key subtransmission, distribution, low-voltage, and secondary system elements. This chapter summarises the network architecture and the key elements that make up our electrical network. Further details of the assets that make up these parts of the network can be found in Chapter 9.

3.2. Transpower grid exit points

Our electricity network is supplied from three Transpower grid exit points (GXPs) at both 110kV and 33kV. The map below shows the transmission network and location of the three grid exit points supplying our network.

Figure 3.1: Transmission network supplying the Northpower network



The following table sets out the voltages used and proportion of customers supplied at each of our three grid exit points.

Table 3.1: Grid exit points – supply voltage and proportion of customers supplied

GRID EXIT POINT	SUPPLY VOLTAGE	CUSTOMERS SUPPLIED
Bream Bay	33kV	9%
Maungatapere	110kV	73%
Maungaturoto	33kV	18%

Northpower also owns assets located at the grid exit points, as set out in the following table.

Table 3.2: Grid exit points – Northpower owned assets

GRID EXIT POINT	NORTHPOWER ASSETS
Bream Bay	33kV power cables and associated sheath voltage limiters (SVL) Electrical protection relays and associated pilot cables
Maungatapere	110kV, 50kV and 33kV power cables 110kV, 50kV and 33kV line termination structures, conductor, and fittings 50kV and 33kV outdoor buses 50kV and 33kV switchgear (circuit breaker and isolators) HV voltage and current transformers 110/50kV and 110/33kV power transformers Local supply transformer Protection and control equipment, including SCADA Control and communication cables
Maungaturoto	33kV line termination structures, conductor, and fittings Part of 33kV outdoor bus 33kV switchgear (circuit breaker and isolators) 33kV current transformers Protection and control equipment, including SCADA Control and communication cables

3.3. Network architecture

3.3.1. Subtransmission network

The map below shows our distribution area and the location of zone substations and subtransmission circuits.

Most remote zone substations are supplied via a single 33kV line, with varying levels of back-feeding capability via the 11kV network. Mobile generation can be deployed for voltage and load support where back-feeding capacity is not adequate.

Detailed information on substation transformer capacity, loading, and security of supply is provided in Appendix C.

Figure 3.2: Northpower's substations and interconnecting subtransmission circuits

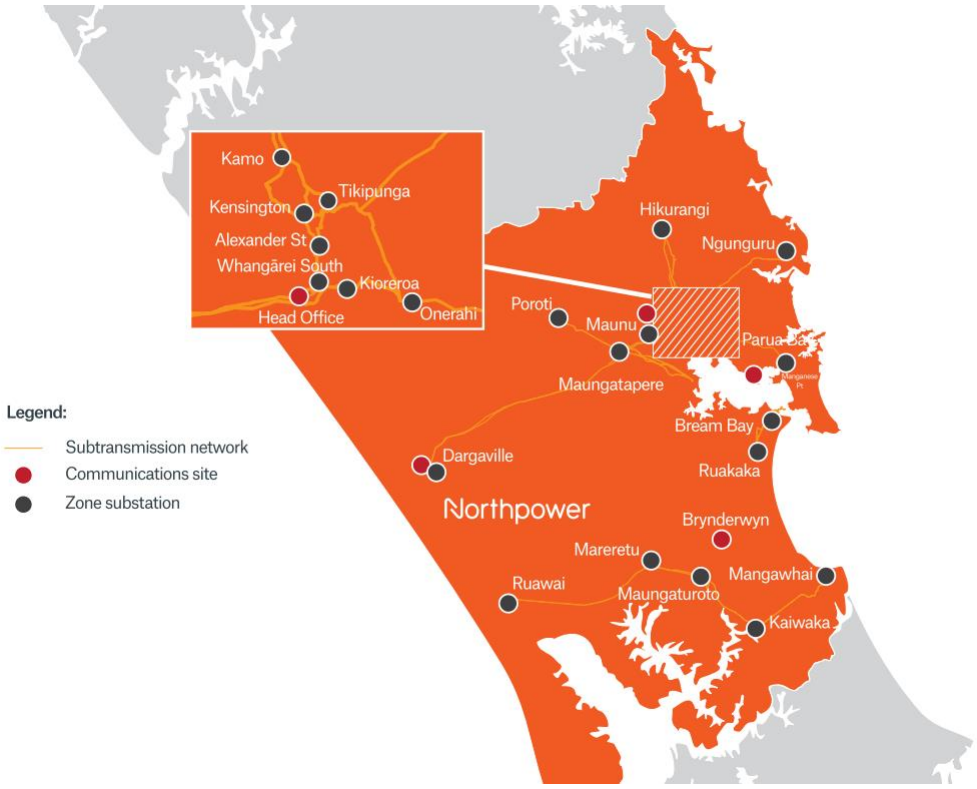
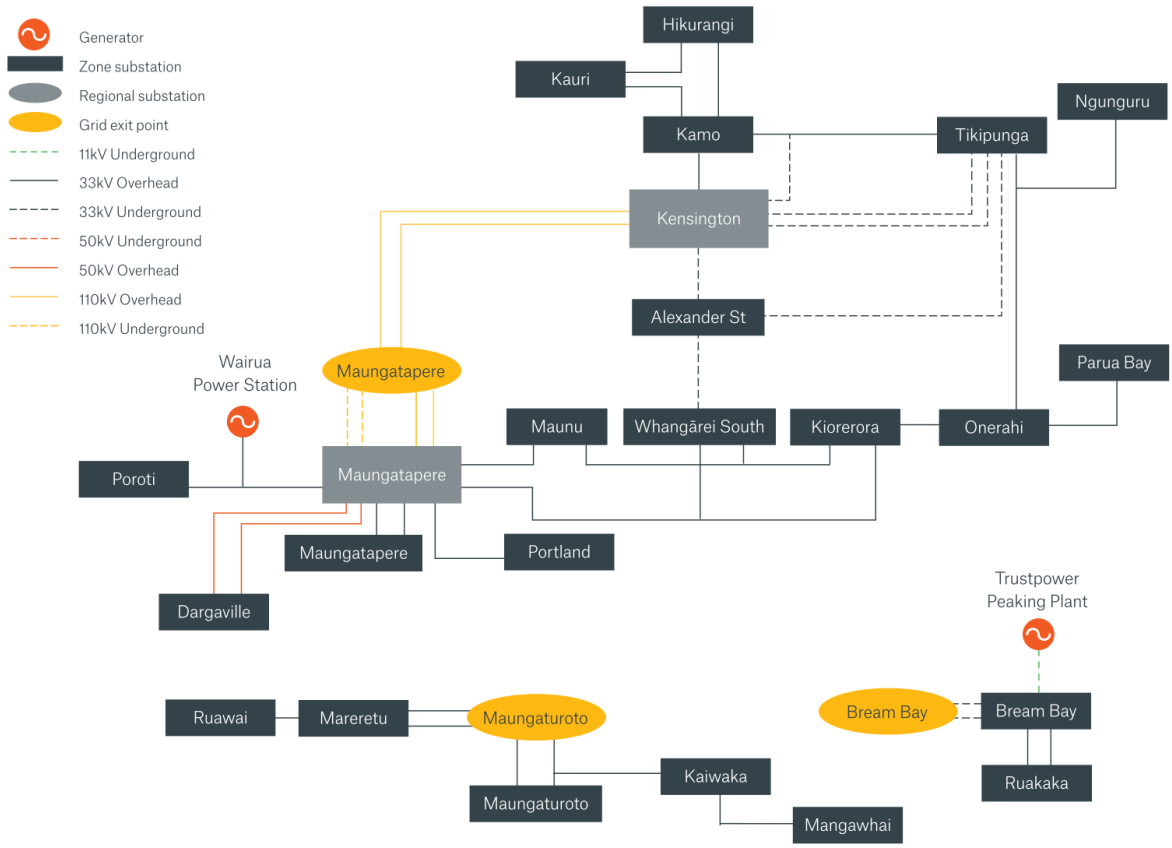


Figure 3.3: Network schematic



3.3.2. High-voltage distribution network

The high-voltage (HV) distribution network originates from the zone substations and includes:

- two 11kV express lines (we use this term for an 11kV feeder with no distributed load connected)
- ninety-eight 11kV distribution feeders and associated low-voltage reticulation.

Most customers are supplied from 11,000/415V distribution transformers; however, some are supplied directly at 11kV. There are also several large industrial customers supplied direct from the 33kV subtransmission network.

Table 3.3: High-voltage distribution network circuit length overhead and underground proportions

HV DISTRIBUTION	UNDERGROUND (KM)	OVERHEAD (KM)	TOTAL (KM)
Circuit length	303 (8%)	3,506 (92%)	3,809

3.3.3. Distribution substations

Distribution substations deployed on the network range in size from 0.5kVA to 1,500kVA and are either pole or ground mounted. They comprise an 11,000/415V transformer, high- and low-voltage fuses, and associated earth grids. Fuses on the high-voltage side of the transformer provide fault protection for the transformer. Fuses on the low-voltage side provide both transformer overload and downstream fault protection for cables or lines.

There are also a small number of 33,000/415V transformers supplying industrial customers.

Transformers with a rating exceeding 150kVA are normally ground mounted due to their weight and size. Transformers with a rating of 50kVA and below can be either two phase or three phase, while those larger than 50kVA are all three phase.

A distribution substation typically supplies one to 100 customers. There are approximately 7,528 distribution substations installed on our network.

3.3.4. Low-voltage network

Northpower's low-voltage (LV) network is a mixture of overhead and underground circuits operating at 400/230V. The LV feeders distribute power from distribution transformers (connected to the 11kV network) to customers' service lines, generally from poles or pillars near property boundaries.

Each LV circuit is protected by fuses at the transformer and each customer point of connection. Electricity meters and ripple relays or pilot control contactors (for control of water-heating load) are generally located at the end of the service line or cable at the installation control point (ICP), or the meter station on the customer's premises.

Where increased security of supply is needed, the LV network is configured in a ring, to allow an alternative supply should it be required. This type of arrangement is common in the central business district and urban residential areas.

Table 3.4: Low-voltage distribution network circuit length overhead and underground proportions

LV RETICULATION	UNDERGROUND (KM)	OVERHEAD (KM)	TOTAL (KM)
Circuit length	812 (41%)	1,182 (59%)	1,994

The point of supply between our network and our customers is generally on the road reserve (at the fusing point). We have information on our website to help customers understand the demarcation point and their responsibilities for maintaining service lines.

3.3.5. Auxiliary and secondary systems

Our main network operations centre (NOC) is located at our headquarters in Raumanga and is attended 24 hours. There is a backup NOC located at one of our zone substations. The electricity network can be fully monitored, managed, and controlled from both the main and backup NOCs.

A SCADA system continuously monitors loads, alarms, and operation of equipment in all substations, including regulators and remote-controlled switches on the network.

Our telecommunication network is integral to the remote monitoring and control of network equipment and utilises radio and fibre optic systems. A separate land mobile radio network gives contact with operating staff and contractors in the field.

Ripple injection plants are installed on our network, providing ripple control signalling to activate load control. This is utilised for hot water load control, streetlights, tsunami warning activation, and other controlled loads.

Metering is installed at Transpower GXP supply points (Maungatapere, Maungaturoto, and Bream Bay) to record energy delivered to our network from the national grid.

Northpower leases a single large mobile generator. Further units are rented when required for managing planned outages.[7]

3.4. Major customers

We have five major industrial customers (VLIs) on our network who have loads over 4MW. With the closure of the Marsden Point oil refinery, the remaining customers are engaged in wood processing, cement manufacture, and milk processing. Before the closure of the refinery, these customers collectively consumed approximately 44.5% of the electricity conveyed across the network. This is expected to significantly decrease in FY23 since the closure of the refinery, as discussed in the network development section.

- Fonterra operates milk processing plants at Kauri and Maungaturoto. The Kauri plant is supplied by two 33kV lines ring fed from the Kensington regional substation. The security of the entire ring is to be further reinforced, and Kauri will derive further benefit with a third 33kV circuit from Kensington to Kamo. The Maungaturoto plant, with a load of more than 4MW, is supplied by the only 11kV feeder. Backup is provided by the ability to switch to a secondary supply through another feeder.

[7] The Northpower group owns a hydroelectric generation installation (Wairua hydroelectric plant).

- The Golden Bay cement manufacturing plant is supplied directly from the Maungatapere substation by two dedicated 33kV feeders owned by Golden Bay.
- The Carter Holt LVL wood processing plant at Marsden Point is supplied by two 33kV cables from the Bream Bay substation.
- Marasumi operates a wood processing plant at Portland, supplied by a single 33kV feeder from the Maungatapere substation.
- The refinery site at Bream Bay is supplied by four dedicated 33kV feeders, which are now significantly underutilised following the closure of refining operations. This is discussed in more detail in Chapter 8.

Although not classed as a VLI customer, Northland Base Hospital is a critical site with a significant and growing load. Recent projects have included the installation of remote-controlled ring main units to enable fast switching to a secondary supply in the event of a loss of normal supply. If demand continues to grow, we may move to a dedicated 11kV or 33kV supply for this customer.

Our VLI customers receive a higher level of service, reflecting their reliance on electricity to operate significant sized and often critical industrial processes. In most cases these customers have dedicated 33kV feeders supplying their site from a Northpower substation, and often have dedicated backup feeders to provide N-1 security. We work with them to understand their security and reliability requirements and ensure our development plans are aligned with their own investment plans. Outages can have major financial impact on these customers, and we actively seek to coordinate our outages for planned maintenance to minimise the impact on their operations.

3.5. Supporting distributed generation

We are investing in our network to support expected increases in distribution generation. These changes will ensure our network can accommodate increasing numbers and size of DER installations.

We take a balanced approach to supporting these installations, acknowledging we need to consider a range of customer outcomes by adopting the following broad approach:

- engaging with customers seeking to connect, discussing their proposed energy solutions with them
- making it easy for customers to access a range of new solutions
- supporting and educating consumers so they can make informed choices
- partnering with providers, other distribution businesses, and industry parties to learn from others and ensure our approaches are consistent with good practice.

3.5.1. Current levels of distribution generation

As of September 2022, there are 1,701 distributed generation systems with a total capacity of 24.2 MW connected to our network.

This includes our Wairua hydro generation plant (5MW) and Manawa Energy's diesel peaking plant (10MW). The remainder are mainly small solar photo-voltaic (PV) systems.

We expect ongoing growth in the number of customers using solar to meet their energy needs. As technology improves and storage options become more affordable, customers will have more flexibility to manage their energy use and participate in the energy market. Ensuring our LV network has sufficient capacity to handle unpredictable customer load profiles has become a key focus of our future network strategy.

Adapting our network to accommodate changes in power flow and customer energy usage demand and patterns requires greater visibility and control of our network. Key initiatives in this area include integration of LV sensors, metering, and installation of devices to gain visibility of our LV network. In addition, we are focusing on the development of data, analytics, and modelling to better understand our capacity, constraints, and opportunities.

We will also continue to take an active education role in the community. Ongoing initiatives include participation in an advisory group with installers to ensure potential roadblocks are removed and constraints understood. We will continue to use periodic surveys to better understand the potential market for solar and the information our customers need.

These initiatives are covered in greater detail in Sections 2.3 and 8.7

In addition to the growth in small-scale distributed generation (DG) on our network, we have seen an increasing interest in connecting large-scale DG to our network. Large-scale DG applications require a significant amount of study and design to be able to connect. This has led us to build more capability in this area. We are also focusing on building capability, systems, and processes to manage large-scale DG once connected to our network.

Chapter content

4 Strategic Context

4. STRATEGIC CONTEXT

4.1. Introduction

This chapter describes our strategic approach that informs and guides the management of our electricity distribution network.

When managing our electricity network assets, we consider how others may be impacted by our actions, activities, and performance. To ensure we identify and address the needs of our stakeholders, we use a strategic framework that provides a structured way of aligning our long-term plans and everyday priorities with stakeholder interests. A key focus is ensuring that we engage meaningfully with our community owners on how we manage our assets.

To support the delivery of our strategic priorities and the asset management principles set out in our asset management policy, we have defined a set of asset management focus areas that guide our efforts to meet the needs of our customers. We need to continue to focus on core services and optimise the existing network, while adapting and upskilling to support our customers' future energy needs.

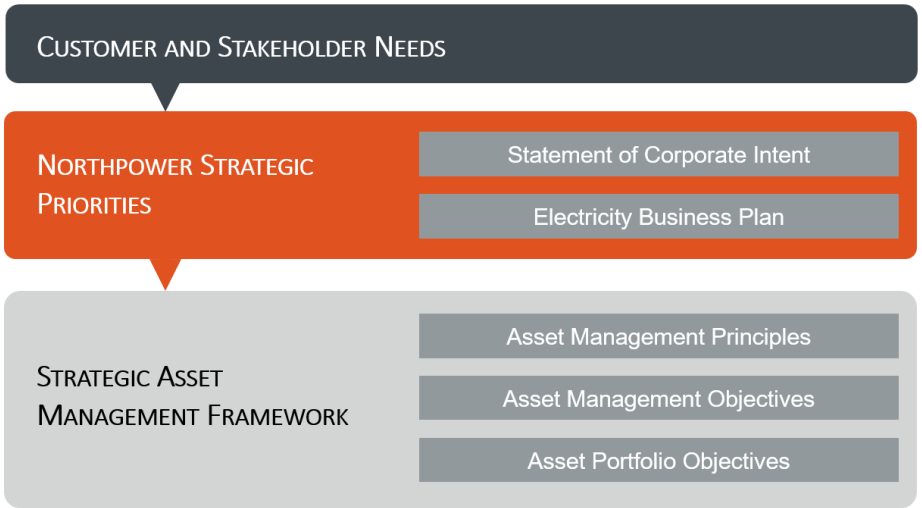
Our asset management documentation describes the approach taken across the lifecycle of our electricity assets, and the methodologies used in managing our asset portfolios and network development investments.

4.2. Strategic alignment

Leading asset management standards (including ISO 55000) emphasise the importance of aligning an organisation's strategic plan with asset management objectives, asset management strategies, and asset management plans, right through to on-the-ground daily activities. Below we explain how we translate our corporate purpose and the needs of stakeholders into our day-to-day investment and operational decisions.

The concept of having clear 'line of sight' between stakeholder needs and daily activities is considered a key feature of effective asset management. This line of sight is illustrated in the key elements of our asset management system. Figure 4.1 depicts this alignment through our strategic priorities and strategic asset management framework.

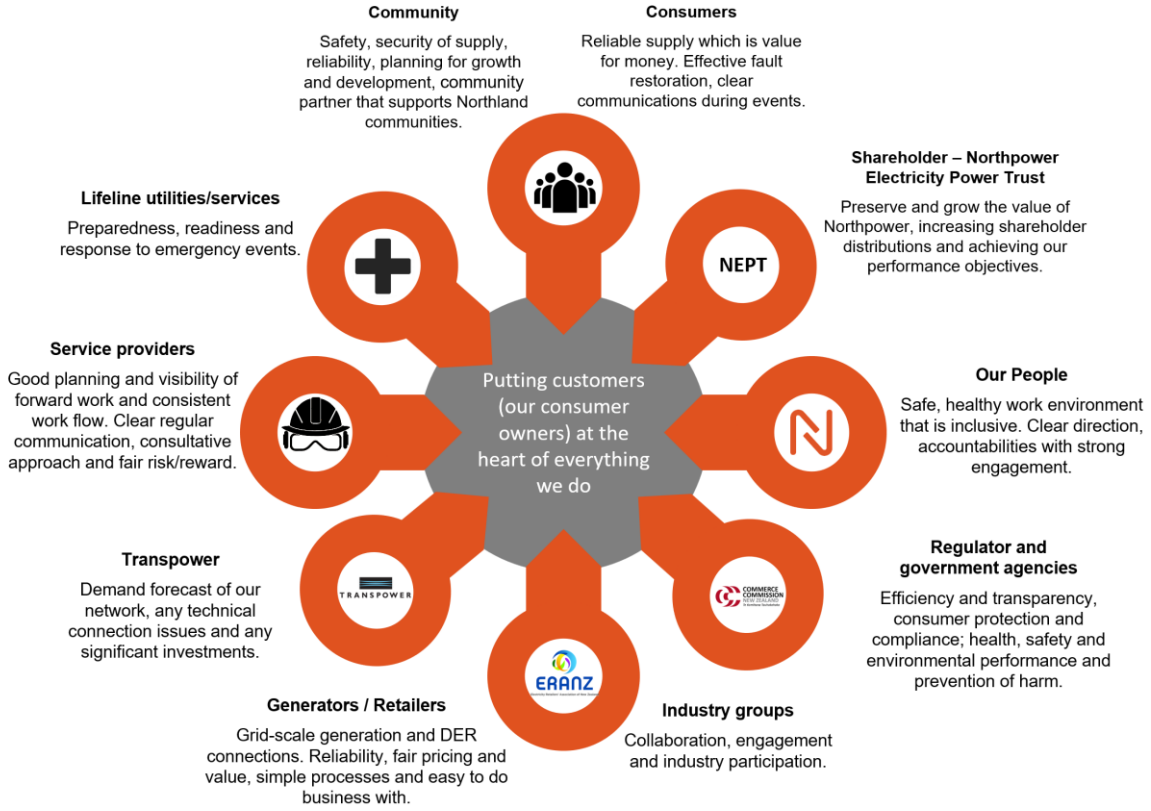
Figure 4.1: Line of sight between stakeholder needs and asset management objectives



4.2.1. Customer and stakeholder needs

To effectively manage complex, long-life assets for a range of stakeholders we need to balance a range of requirements. To do so, we exercise our best judgement and strive to engage with our community owners to transparently explain our investment decisions, including through this AMP. Figure 4.2 summarises the interests of our consumer owners and other stakeholders.

Figure 4.2: Our key stakeholders and their main interests



When managing our electricity network assets, we consider how others may be impacted by our actions, activities, and our performance. Development of our AMP and investment plans considers the interests of our stakeholders and reflects these in our strategies and plans. We include further detail on our approach to customer engagement in Section 2.4.

4.2.2. Northpower strategic priorities

Northpower's overarching purpose is to generate value for the regions of Kaipara and Whangārei from infrastructure ownership. Northpower provides consumers with the benefits of ownership through a combination of posted discounts on their distribution charges (passed on through their power bills) and dividends through the NEPT.

Northpower has a tight focus on returning value to the community, including reliable electricity network operations, strong commercial performance, and wider economic benefits for the North. As a key large organisation in Northland, we contribute to the local community via employment, training and skills development, local expenditure, sponsorship, and community collaboration with other organisations.

This overarching purpose is summarised in our group mission.

Box 4.1: Group mission

Our group strategy is guided by an overarching mission:

Connecting communities, building futures, for Northland

We deliver on this by supporting positive economic outcomes through our infrastructure, social outcomes through skills and capability building, and having a direct, supportive financial impact through distributions. We generate value through the management of our networks, services, and investments, while enabling a low-carbon future. Together these will benefit our consumer owners in Northland and the communities we serve.

To guide how we deliver on our group purpose we have defined three strategic pillars.

Delivering for our people and communities

Protecting lives and well-being

We continue to prioritise health and safety to prevent serious harm to our staff, service providers, and the public.

Keeping communities connected

As a cost-effective asset manager, we continue to act as a champion to keep delivered electricity affordable for our consumers and help our customers manage their total electricity costs. We 'keep the lights on' for over 62,000 Northland homes and businesses.

Delivering valued outcomes

We engage with our community owners to understand their needs and actively partner with iwi and mana whenua to make informed decisions. We invest in and operate our assets in a way that respects and cares for cultural aspects.

Enabling our future

Enabling a low-carbon future

We will enable renewables and electrification in the North, including by investing in distribution and transmission assets and systems to support New Zealand's transition to a low-carbon energy future.

Building future-ready talent and leadership

We continue to bring in and develop new staff via our capability academy, Whare Ako, and to grow technical skills and create career pathways. We will continue to build a more diverse, inclusive, and equitable organisation. We will integrate new technology and field tools, enhancing our services and increasing productivity.

Enabling communities to thrive and prosper

We will continue to grow returns to our shareholders. We will sponsor causes aligned to our community, supporting skills development, and education. We support local suppliers and contractors to grow and increase local procurement value.

Protecting our environment

Reducing our carbon emissions

We commit to reducing our own carbon emissions, aligned to a science-based target of 1.5 degrees of global warming.

Minimising our impact on the environment

We are committed to being environmentally responsible and limiting activities that have adverse impacts on the environment. We have an ongoing focus on waste minimisation through continuous improvement and efficiency initiatives.

The targets within our statement of corporate intent (SCI) underpin our focus on delivering positive outcomes to the communities we serve.

4.2.3. Our electricity business plan

Our electricity network plays an important role in delivering the strategic goals discussed above. Its core function is to deliver a safe, affordable, and reliable supply of electricity to our customers, now and into the future. Our role is broader than maintaining and operating today's network; it extends to meeting future needs and enabling a more sustainable energy future.

Box 4.2: Electricity strategy

Our electricity strategy is guided by an overarching mission:

Enabling our communities to thrive by powering a more sustainable future

Our strategic pillars are applied to our electricity network through our electricity business plan. We need to continue to enhance our focus on core services, while optimising the existing network. We will adapt and upskill to support our customers' future energy needs.

We have expended our electricity strategy into three main themes.

Enabling our communities to thrive by powering a more sustainable future

Safe, reliable, and resilient

The core function of our electricity network business is to deliver a safe, efficient, and reliable supply of electricity to our communities, resilient to climate change, now and into the future.

Sustainable outcomes

Develop and manage a network that drives sustainable outcomes for our communities, including effectively integrating distributed energy resources.

Supporting our communities

Unlock affordable energy solutions, helping customers reduce overall energy costs and supporting energy decarbonisation.

Safe, reliable, and resilient

The principal objective of our electricity network business is to provide a safe and reliable supply of electricity for the benefit of the electricity consumers of Kaipara and Whangārei. To continue to do this, we need to invest in our network and capability and ensure we deliver a sustainable energy future for our customers. To support this, we are:

- expanding our asset investment programmes that maintain a safe, resilient, reliable, and future-ready network
- optimising asset spend through enhanced asset management and analytics
- increasing our focus on resilience investments to ensure we can meet the increasing impact of climate change
- lifting investment in our electricity network to ensure it continues to provide a safe, secure, and reliable supply of electricity, accommodating growth in our region and supporting integration of new energy solutions.

Sustainable outcomes

We use the terms 'sustainable outcomes' to refer to our aim to ensure, as far as practical, that our assets and operations have a positive impact on people's safety and well-being, and the environment. We take a long-term view of our operations to ensure a sustainable future for the people of Northland. To help achieve this we will:

- facilitate the integration of DER on our network, making Northland a preferred region for renewable energy technologies
- investigate cost-effective, innovative ways of supporting network augmentation to enable renewable energy development

- consider how we can actively support the decarbonisation of industry in Northland.

Supporting our communities

Our electricity business plan reflects the emergence of new renewable energy supply options, such as rooftop solar and electric vehicles, which are complementary to our current energy supply arrangements. Such developments herald a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use.

Northpower is committed to supporting this natural integration of new energy solutions, and our networks are a key platform to support their implementation.

In addition, we acknowledge that energy hardship is a growing issue in our community, and we are committed to helping our customers manage their total energy costs and be more energy efficient.

We are refining the way we charge our customers to ensure the charges we impose are reflective of actual cost, ensure equitable and fair charges as new energy solutions emerge, and put a focus on managing our wider business operations in a way that will enable us to lift the level of rebate we provide our customers over time. We will do this by:

- optimising demand across our network to utilise existing capacity and avoid unnecessary upgrades (through demand response platforms, pricing incentives, supporting distribution system operator development)
- engaging with our communities and stakeholders to support the adoption of new technologies
- focusing on costs through continuous improvement and efficiency initiatives.

Supported by effective engagement

The above aims and initiatives will need to be underpinned by meaningful, effective engagement with our community owners and partnering with iwi and mana whenua to make informed decisions.

We are improving the way we work with customers by streamlining and modernising the way stakeholders can engage with us. We are creating new options locally for completing work associated with our network, and taking an active stance in understanding, enabling, and providing advice on new energy options.

4.3. Strategic asset management framework

Our strategic asset management framework sets out principles and objectives that help us ensure our investments deliver safe, cost-effective electricity services that meet the current and future needs of Kaipara and Whangārei communities.

4.3.1. Asset management principles

Our asset management policy sets out a set of asset management principles that reflect the aims of our electricity business plan. It reflects our expectations for the way we will manage our assets. The policy has been developed to ensure a continuous focus on delivering the services our customers want in a sustainable manner that balances risk and long-term costs.

Asset management policy statement

Northpower is committed to managing its electricity distribution assets in a way that provides customers with safe, reliable, affordable, and sustainable services. We demonstrate this commitment by delivering on the following asset management principles:

- **a safe network**: our electricity assets and operations will not cause harm to members of the public, our staff, or service providers
- **delivering customer outcomes**: we deliver valued services to customers that are safe, reliable, and efficient
- **meeting demand**: our networks and operations will efficiently meet future demand for electricity services
- **protecting our environment**: we minimise the environmental impact of our assets and our operations
- **capability**: our people are trained and competent, and demonstrate a commitment to and understanding of asset management
- **resilient services**: our networks and operations are resilient, including to the increasing impacts of climate change
- **future services**: we proactively develop new solutions to enable ongoing flexibility in meeting the changing needs of our customers and future energy markets.

This policy guides the development of our asset management objectives, plans, and activities to ensure Northpower delivers outcomes valued by customers.

To deliver on these principles, we will focus on the following behaviours:

- **engagement**: building effective relationships with the communities that host our assets and actively partnering with iwi and mana whenua to make informed decisions
- **customers**: engaging with our customers about how we manage our assets
- **consistency**: aligning our asset management activities with our strategic priorities, enabling us to meet our performance targets
- **compliance**: complying with all relevant laws and regulations
- **commitment**: developing and maintaining an asset management system that complements and supports our business, in accordance with ISO 55001

- **resources**: assigning enough resources (people and funding) to deliver on our asset management objectives
- **improvement**: ensuring continuous improvement of our asset management system through effective systems and setting measurable objectives and targets.

4.3.2. Asset management objectives

To ensure appropriate line of sight, our asset management framework translates our asset management principles into asset management objectives that guide our investment and operational decisions. To support consistent alignment, we have defined seven asset management focus areas (see Section 4.4) that build on our group strategy, electricity business plan, and asset management principles.

We have defined performance indicators (see Chapter 6) in each of the focus areas. These inform our asset management decision-making and set the direction for managing our electricity distribution network. They have been developed to achieve the following aims:

- ensure that our organisational objectives are effectively delivered by our day-to-day asset management activities
- focus on outcomes that are meaningful to customers and other stakeholders
- monitor progress on how well our asset management activities deliver valued outcomes for our community owners
- guide our investment decision-making so that we efficiently deliver our electricity business plan
- inform our continuous improvement programme.

We set ourselves targets in each of the focus areas and monitor our performance in meeting the targets. Chapter 5 sets out recent performance against our targets.

4.3.3. Asset portfolio objectives

Portfolio objectives guide our day-to-day asset management activities in each of our asset portfolios. These are organised based on our seven asset management focus areas. Our asset portfolio objectives are set out in Chapter 9.

4.4. Asset management focus areas

To support the delivery of our strategic priorities and the asset management principles set out in our asset management policy, we have defined a set of asset management focus areas. The seven focus areas are:

- **safety**: the need to protect the public, our staff, and our service providers informs everything we do
- **delivering for customers**: outcomes that reflect the levels of service provided to our customers
- **network performance**: reflecting the performance of our network assets and the quality of service we deliver to customers

- **environment**: protecting the environment from the risks posed by our assets and preparing our network for climate change
- **supporting communities**: managing our assets prudently and efficiently to ensure we deliver cost-effective and valued services to the communities we serve
- **capability**: developing our people and improving our asset management system
- **future readiness**: our ability to deliver new solutions that can meet the changing needs of our customers and facilitate future energy markets.

These focus areas have been developed to enable and support the delivery of our corporate objectives and meet the needs of our customers.

In Chapter 5, we set out asset management objectives and initiatives under each of the above focus areas.

4.4.1. Safety

Safety is our foremost organisational value. We believe that all incidents are preventable, and that no other objective should override the safety of our employees, service providers, or the general public. Our network assets and some asset management activities pose potential hazards to our workers and to the general public.

We continually challenge ourselves to protect life and put people's safety and well-being at the heart of Northpower. As an electricity asset owner, we are responsible for safeguarding both those working on our network as well as the wider public. As an employer, we aim to ensure an injury-free workplace and promote the well-being of our people.

Protect life and keep the public, our staff, and service providers free from harm

We will achieve this by:

- ensuring our network and our activities do not cause harm to the health and safety of the public, our staff and service providers
- adopting 'safety in design' principles for planning, building, and maintaining our network
- implementing a robust corrective maintenance programme to address defects that may lead to safety risks
- proactively identifying and investing in improvements to our network to improve health and safety
- ensuring vegetation management targets areas of our network with potential safety risks.

4.4.2. Delivering for customers

We recognise that our customers are best placed to define what 'value' means to them. This is a change in emphasis from using performance measures purely focused on asset performance to measures that reflect the service customers receive. Doing so will help better target our capital investments and operational activities to deliver performance that our customers value. This includes increased proactive engagement with Māori around natural resources and cultural values.

Deliver services customers want and value, maintain trust to retain our licence to operate

We will achieve this by:

- actively seeking to understand and meet our community owners' needs, now and in the future
- continually improving our customer engagement and our customer service
- being socially responsible in our actions
- implementing our sustainability strategy to promote positive community outcomes
- undertaking analysis to gain deeper insight into metrics that reflect customer outcomes
- increasing our engagement with customers, communities, and mana whenua to better understand how our assets and activities impact them and to make more informed decisions.

4.4.3. Network performance

The service that our customers receive reflects the performance of our network and its constituent assets. Network performance depends on how well we manage and maintain asset condition and how well we deal with interruptions when they occur.

The capability and performance of the network today reflects historical trade-offs between cost and service. Future trade-offs should be based on changing customer preferences and the need to deliver a safe, reliable, affordable, and resilient service.

To deliver appropriate levels of network performance we plan to increase our focus on customer outcomes. This will establish the aspects of our performance that should guide our performance measures and targets. Achieving appropriate levels of network performance is a key driver for our capital investment and maintenance levels. This will also support the ongoing integration of new energy solutions.

Manage risk, asset lifecycles, and network operation to deliver a safe, reliable, and resilient system

We will achieve this by:

- achieving our performance targets as set out in our statement of corporate intent
- planning and investing to replace end of life assets and cater for growth
- considering asset condition, risk, criticality, and whole-of-life costs in making asset management decisions
- investing to enhance resilience and prevent extended outages
- proactively managing quality of supply, network capacity, and constraints.

4.4.4. Environment

Our behaviours and values recognise the role of kaitiakitanga (guardianship) that expresses the importance of good stewardship of the environment. We are committed to being environmentally responsible and ensuring we do not cause harm to the environment. We will identify and manage works in cultural sites (urupā, pā, etc.) through a collaborative and

consultative approach with stakeholders. We strive to protect archaeological sites so we can identify, preserve, and protect heritage structures.

We take a long-term view of our operations to ensure a sustainable future for Northland. We strive to exceed regulatory requirements across all our operations and projects, focusing on environmental enhancement. We aim to limit the negative impacts our assets and activities have on our communities and the environment as far as practicable. A key objective is to ensure our operations do not cause harm to the environment.

Increasingly, in the context of climate change, we recognise the part we should play in supporting Northland's longer-term adaptation needs and decarbonisation aims. Environmental benefits can be achieved by facilitating and supporting the development of renewable generation and the decarbonisation of transport. We discuss this further in Section 4.4.7.

Practice stewardship, ensuring our assets and activities do not adversely affect the natural environment

We will achieve this by:

- ensuring our network and our activities do not cause harm or adversely impact the natural environment
- fulfilling our legal responsibilities
- minimising Northpower's sulphur hexafluoride (SF_6) emissions
- operating oil containment facilities and adopting oil spill mitigation procedures
- using resources sustainably and ensuring responsible disposal of waste to minimise negative environmental outcomes
- reporting on our progress on climate change risk mitigation
- assessing our emissions baseline and developing plans to reduce it.

4.4.5. Supporting communities

As a trust-owned business, Northpower has a strong focus on ensuring equitable and sustainable outcomes for our consumer owners. Our trust ownership ensures the profits we make are returned to the communities we serve. Since 1993, this arrangement has delivered more than $250 million to our connected electricity consumers.

Delivering a valued service for customers means that we provide positive outcomes to customers at an efficient cost. To achieve this, we challenge ourselves to improve our cost performance through efficiency initiatives and innovation. This will enable us to deliver safe, reliable services for our customers at lower cost over the medium to long term. Effective asset management will help ensure this expenditure is prudent and efficient, delivering a cost-effective service to our customers.

Support Northland's communities by unlocking affordable energy solutions, reducing overall energy costs for consumers

We will achieve this by:

- focusing on reducing whole-of-life costs across our network assets
- giving customers connected to the network a pricing discount on our distribution charges
- ensuring our pricing is fair, transparent, and equitable for all consumers
- helping customers navigate their energy choices and make informed decisions
- working closely with key stakeholders, community leaders, social organisations, and government agencies to support affordable outcomes
- running our ongoing energy education programme (see Chapter 2)
- running information programmes to help customers reduce their total energy costs.

We provide more detail on how we are supporting affordable outcomes in Section 5.6 where we set out our ongoing efficiency and pricing initiatives in more detail.

4.4.6. Capability

We are committed to continually improving our asset management capability. Effective capability development (e.g. embedding appropriate processes, systems, and techniques) is a key enabling step, and we will continue to focus on this in the foreseeable future. We will continue to develop our asset management skills, processes, and systems to achieve our objectives and deliver on our purpose. These improvements will help us to better understand network performance and to further optimise our investments.

Our organisational asset management capability is the result of our people, the tools we use, and the processes we follow. Ensuring we have enough people with the right competencies is essential if we are to achieve our asset management objectives.

Promote robust asset management capability to deliver a safe, reliable, affordable, and resilient system

We will achieve this by:

- seeking out and addressing gaps in our capability
- lifting our digital and analytical capability
- developing and implementing an asset management competency framework
- aligning our asset management and risk management with the ISO 55000 and ISO 31000 frameworks
- ensuring we have the skills and capability to operate a future-ready network
- evolving our capability to ensure we focus on delivering valued outcomes.

The levels of network investment we are proposing are significant. This will also require investment in our people and decision-making tools. This is necessary if we are to maintain

the capability necessary to be effective asset managers and increase efficiency. Our asset management planning will evolve and shift to a largely proactive approach.

In the coming years we anticipate that effective workforce competency planning and training will become increasingly critical, as older and experienced staff retire. For this reason, we are placing an increasing focus on formal competency planning.

4.4.7. Future readiness

The future readiness focus area sets out how we will prepare for the wider adoption of distributed energy resources (DER) and support efforts to promote decarbonisation. We expect to see significantly more EVs, photo voltaic installations, and battery storage systems installed on our network. To support this, it is prudent to prepare for increased uptake of these resources now rather than react at a later stage. Ongoing technology advances are opening opportunities for new solutions.

The uptake of DER and EVs can lead to network congestion and potentially limit our ability to host further installations. Increasing electrification is likely to require the provision of additional network capacity. These constraints would undermine our efforts to enable customer choice and to promote decarbonisation through increased electrification. To address this, we are now investigating how we can best deliver a future-ready network. This will involve assessing future scenarios to support informed investment decisions that will future-proof our network.

Digital enablement will be key to ensuring our future readiness. This includes integrating network information to drive insights and improve decision-making. Accessing and managing new information (e.g. LV network visibility) will help us understand hosting capacity, demand, and constraints. Digital enablement will also allow greater insights into asset condition and the effectiveness of maintenance, helping us to optimise asset renewal.

These improvements will be necessary if we are to optimise the integration of DER and help ensure that Northland is a preferred region for renewable energy investments.

Our network will enable sustainable outcomes for our community and support New Zealand's decarbonisation

We will achieve this by:

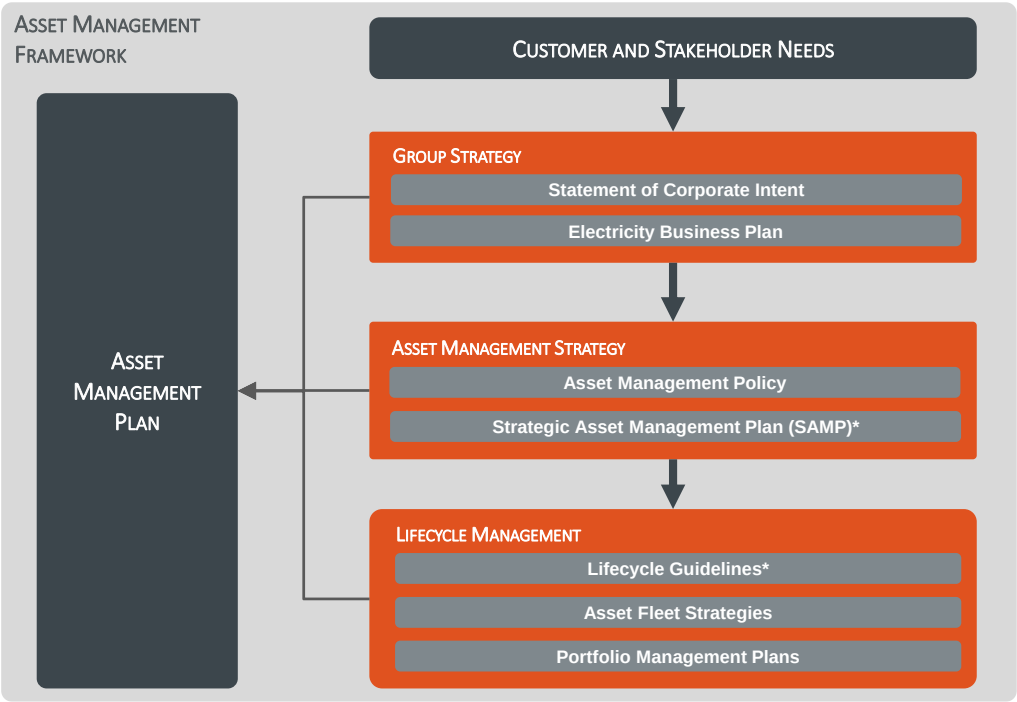
- helping customers understand new technologies and how to connect these to our network
- working with customers to integrate new energy resources on our network and find cost-effective ways to alleviate network constraints
- supporting our communities to transition to a low-carbon future, including the adoption of EVs
- implementing systems that provide increased visibility and active management and control of the network
- developing new standards to cater for integration of DER
- collaborate with the wider distribution industry, ENA, and other stakeholders to leverage their knowledge and experience.

4.5. Asset management document suite

Our asset management system is supported by a hierarchy of asset management documentation. The documentation seeks to reflect good industry practice[8] and explains our overall approach to asset management.

As depicted in Figure 4.3 below, we organise our core set of asset management documents into a hierarchy that begins with the views of stakeholders informing our group strategy and asset management strategy material, before being implemented though our day-to-day life cycle management activities.

Figure 4.3: Asset management document hierarchy



* These documents are in development

4.5.1. Stakeholder needs

Our asset management document hierarchy has been developed to reflect the needs of our customers and stakeholders. This includes ensuring that we consider how others may be impacted by our actions, activities, and performance. Development of our AMP and other asset management documentation considers the interests of our stakeholders and reflects these in our strategies and objectives.

[8] Our framework will evolve as we progress our asset management improvement initiatives in alignment with ISO 55001.

4.5.2. Statement of corporate intent

Our statement of corporate intent (SCI)[9] is a governing document setting out Northpower's performance commitment to the NEPT and our consumer owners.

The operations of the Northpower group are overseen by a board of directors that uses the SCI to guide the direction and deliverables from the group. Targets set out in the SCI include financial and non-financial measures such as network reliability and customer satisfaction. These KPIs reflect discussions between NEPT trustees and Northpower directors on our purpose, outcomes, and community role.

4.5.3. Electricity business plan

Our electricity business plan sets out how the management of our electricity network supports our corporate objectives as set out in the SCI. As discussed in Section 4.2.3, it reflects the interests of internal and external stakeholders who have an active interest in how our electricity network is managed.

4.5.4. Asset management policy

Our asset management policy (discussed in Section 4.3.1) aligns our asset management approach with our electricity business plan. It provides overall direction and guidance for our asset management approach.

The policy sets out high-level asset management principles that reflect our purpose as a consumer-owned electricity distributor. The policy has been developed to ensure we continually focus on delivering a valued service for our customers.

4.5.5. Strategic asset management plan

We are developing a strategic asset management plan (SAMP) to act as an overarching document that sets out our asset management objectives. It will incorporate objectives and KPIs aligned with our group performance targets and will provide strategic direction for asset fleet strategies (discussed below). The SAMP will distil our corporate objectives through our asset management policy and set out asset management level objectives in the seven focus areas described in Section 4.4.

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9 Northpower SCI

4.5.6. Lifecycle stage guidelines

We are developing a set of lifecycle stage guidelines. The four guidelines will describe our approach to the particular activities in each life cycle stage and strategies for improving these. The following four lifecycle guidelines reflect the lifecycle stages we use when organising our asset management activities (this is discussed in Chapter 6).

- **Network development guideline**: will cover processes for identifying growth and security Capex, from need identification through to options analysis and approval.
- **Design and build guideline**: will explain how we implement capital works, including design, procurement, installation, and commissioning.
- **Operate and maintain guideline**: will cover our approach to maintaining our electricity assets, including the types of maintenance employed. It will cover operation of the assets, including outage coordination and contingency planning. This is supported by our network vegetation management strategy.
- **Renew or dispose guideline**: will cover activities related to the renewal of our network assets and the disposal and decommissioning of assets.

4.5.7. Asset fleet strategies

Our asset fleet strategy documents reflect our asset life cycle model and set out how these processes and activities are applied to individual asset fleets. We are currently developing this suite of important documents. These have been summarised in Chapter 9.

4.5.8. Portfolio management plans

Reflecting our delivery approach, we aggregate planned asset fleet interventions into an overarching portfolio management plan. These set out a summary of activities and costs for the particular portfolio over a set period. These are used to manage the delivery of our capital investments and our proactive maintenance activities. These plans help ensure that project and maintenance work is scheduled and delivered efficiently.

4.5.9. Asset management plan

Our electricity network AMP (this document) is a stakeholder-focused summary that reflects our overarching approach to managing our electricity distribution network. It sets out asset management objectives and investment plans over the AMP period, focusing on explaining these to stakeholders and complying with relevant disclosure requirements.

Development of our AMP

The development of our AMP is a collaborative effort combining the skills, experience and knowledge of our staff and the need of stakeholders. Figure 4.4 shows our AMP development process, the role of our board and management, and consultation with stakeholders.

Figure 4.4: AMP development process

	Board	Management	Stakeholders
Strategy Align strategy, business plan and asset management policy with our SCI, and feedback from customers and stakeholders	• Strategy review session and review of asset management focus • Approve the SCI, business plan and expenditure budgets	• Consider shareholders' expectations in developing strategy • Stakeholder consultation	• Analyse external factors, performance, capability and risk • Test business strategy and asset management strategy
Performance Review Monitor and analyse performance and service levels, report and adjust operations to improve outcomes	• Confirm service level assumptions • Review progress on AMP and expenditure plans	• Review/report progress on AMP and expenditure, and network performance, • Review load growth, capacity constraints, security, asset risk	• Stakeholder consultation and consider shareholders' expectations
Business Cases Ensure prudent and efficient investment decisions based on data, evidence and sound engineering judgement	• Review business cases and ensure appropriate investment decisions made • Approve investment business cases (greater than CEO DFA)	• Prepare business cases and ensure necessary capability is available • Peer review business cases with external review as appropriate	• Stakeholder consultation and consider shareholders' expectations
Develop AMP Communicate our asset management policy, strategies and expenditure plans to ensure best practice stewardship of our electricity network	• AMP strategy, focus areas and expenditure principals • Approve AMP, expenditure budgets and Information Disclosures	• Prepare AMP, investment plans, and expenditure budgets • Manage reviews of AMP, compliance review of Information Disclosures	• Stakeholder consultation and consider shareholders' expectations

The process involves gathering inputs from subject matter experts within the business, internal peer review by senior management, external review by asset management specialists, and testing against customer and stakeholder feedback. Our board approves the AMP to ensure it meets our commitments and the expectations of the trust and our consumer owners. This approach helps to ensure our investment plans efficiently and effectively meet the future needs of the communities we serve.

Public comment and feedback are welcomed and carefully considered.

Chapter content

5 Our Performance

5. OUR PERFORMANCE

5.1. Introduction

This chapter outlines how we monitor and manage our performance. It sets out how we measure performance and our plans to meet these targets over the planning period. We continually review our performance to ensure we continue to meet the needs of our community. Key performance indicators such as safety, reliability, and customer satisfaction are set out in our SCI.

Our performance monitoring is broadly classified to align with our asset management focus areas (discussed in Chapter 4). In some areas (e.g. emissions) we have begun to collect performance information but have not yet set related targets.

Northpower is committed to safeguarding the public and ensuring an injury-free workplace. Safety is about people, including our employees, subcontractors, and the general public. We want to ensure that everyone goes home to the people, places, and things that mean the most to them.

Our electricity network provides an essential service to the communities of Northland. Understanding what matters most to our customers and their satisfaction with our services helps to ensure our service remains relevant for customers. This is a key commitment in our SCI and a key focus area of our asset management strategy.

We have measures and targets to track our progress in reducing any negative impacts our assets and operations may have on the environment. This extends to ensuring our network and operations are ready for the growing challenges of climate change.

We engage with our customers to understand their needs and what they expect from us in terms of network performance. Customers tell us that a reliable electricity supply remains a top priority. Delivering a reliable service is a key focus for us, and related targets are included in our SCI.

Reflecting our trust ownership model, we maintain a strong focus on delivering our service efficiently and using fair pricing to keep service costs low. We plan to explore potential performance indicators to help ensure we continue to deliver cost-effective services to our customers.

Additionally, we have measures and targets to track our progress in improving asset management capability and ensuring our network is ready for the evolving energy markets.

5.2. Safety

Our electricity network assets and related activities may pose hazards to the public and to our staff. We are committed to safeguarding the public and ensuring an injury-free workplace. When operating our network, we take all practical steps to minimise the risk of harm to the public, contractors, and our people.

Health and safety is about people. Our approach to health and safety encompasses the relationships between our people, the work they do, and the environment they do it in, held together with leadership. Our aim is to operate our network free from harm.

The Health and Safety at Work Act 2015 states the objective of "protecting workers and other persons against harm to their health, safety, and welfare by eliminating or minimising risks arising from work". This goal is reflected in our approach to managing safety on our electricity network.

Effective management of health and safety risks associated with our assets and activities is fundamental to our business and to fulfilling our statutory obligations. To ensure our network does not present significant risk to public safety we ensure we comply with the Electricity Safety Regulations 2010. All potential public safety risks identified are managed to a level that is 'as low as reasonably practical'.

We are responsible for ensuring the safety of all electricity reticulation and equipment from the GXP up to the customer's point of supply. We ensure that network assets are appropriately secured, preventing unauthorised entry or access to exposed live equipment.

We certify our approach and process to managing public safety.[10] Compliance requires ongoing monitoring of our approach which is tested through an audit by an accredited third party at least once every three years. Surveillance audits are carried out annually between the accreditation audits. We passed our last accreditation audit in January 2021 and surveillance audit in December 2022.

5.2.1. Safety targets

The following key performance indicators (KPIs) are used to track our safety performance. We closely monitor our performance against the annual limits/maximums, and the measures are reviewed annually. The KPIs set out our anticipated performance and originate from two sources:

- group-wide SCI performance commitments to the NEPT and customer owners
- Northpower network's public safety management system (PSMS).

Table 5.1: Northpower group and network safety targets

PERFORMANCE INDICATOR[11]	SOURCE	FY23	FY24	FY25
Total recordable injury frequency rate (TRIFR)	SCI	≤ 6	≤ 6	≤ 6
Permanent disability or fatality	SCI	0	0	0
High potential event frequency rate (HPEFR)	SCI	5	5	5
Instances of public harm	PSMS	0	0	0
Known near misses that could have caused public harm	PSMS	< 3	< 3	< 3
Instances of property damage	PSMS	< 10	< 10	< 10
Near misses that could have caused property damage	PSMS	< 15	< 15	< 15

10 NZS7901:2014 Electricity and Gas Industries - Safety Management Systems for Public Safety.

11 The long-term target is zero for all instances and near misses of public harm and property damage. The remaining targets remain in place for the planning period, though they will be subject to periodic review.

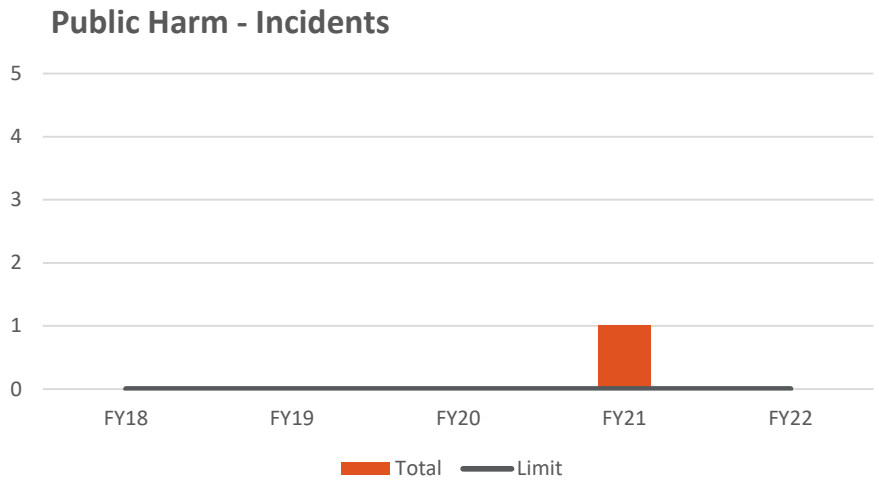
Public harm and property damage measures cover incidents caused by Northpower staff, assets, or equipment. It does not include incidents caused by the public. Events that may cause the public harm are thoroughly investigated. Property damage does not include anticipated damage caused by construction, maintenance, and fault restoration that is reinstated on completion of the work. Near misses are incidents that created a potential risk rather than actual harm or damage. These are also included for investigation so that we can make improvements to avoid further risk.

5.2.2. Safety performance

Below we summarise our recent performance against our key safety targets.

Public safety reporting

Figure 5.1: Public harm incidents

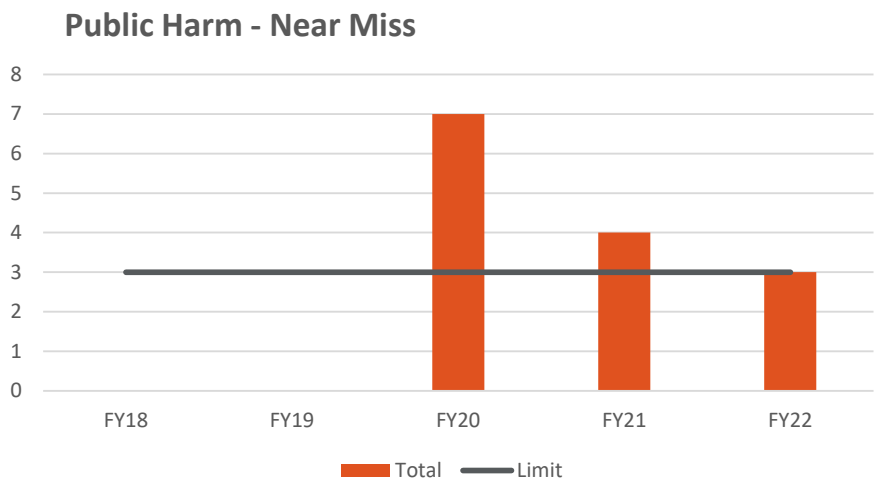


While we have met this target last year and the majority of recent years, there was an incident in February 2021 when a customer received an electric shock from the guy wire of a power pole when tying up his tomatoes to it.

On initial response Northpower found that the guy wire had been rubbing through a live conductor (a jumper) on a power pole. The guy wire became live with 230V. The incident was treated as a high potential event and WorkSafe New Zealand was informed.

Our root cause findings were that the initial installation, over 20 years ago, of the guy wire on the power pole was inadequate and there was no protection on the guy wire. A sample of power pole installations with guy wires and their construction methods determined that this was an isolated event. We reviewed the training of pole inspectors and have improved the standard and detection system since this event.

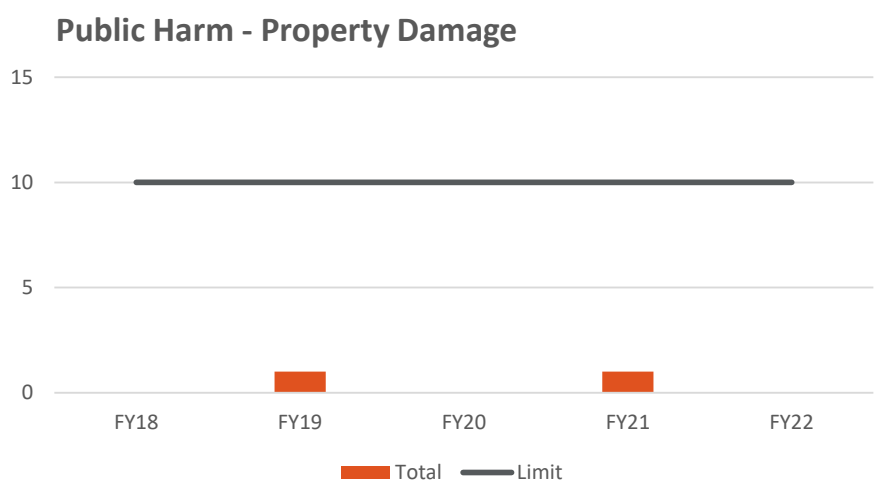
Figure 5.2: Public harm – near miss



Our network business changed public safety reporting systems in FY19. The change brought greater reporting of events, initially in FY20, that has moderated in the last three years as definitions were better understood. Our public safety reporting focuses on:

- Northpower asset events which caused harm or had the potential to cause harm to the public (that is, the operation of our network in normal and fault conditions). Examples are power lines down, low-lying conductors, pillar fires.
- Public harm events (incidents and near misses) reported here are those in which Northpower, or our contractor workers, was involved in their causation.
- The public interacting with our assets in normal operation which caused harm or had the potential to cause harm to the public. Examples are underground cable strike, unauthorised access to network assets, vehicles versus assets.

Figure 5.3: Public harm – property damage



Greater visibility of public safety events and increased asset safety has also led to a reduction of Northpower caused events. Further refinements to our public safety reporting are planned for 2023.

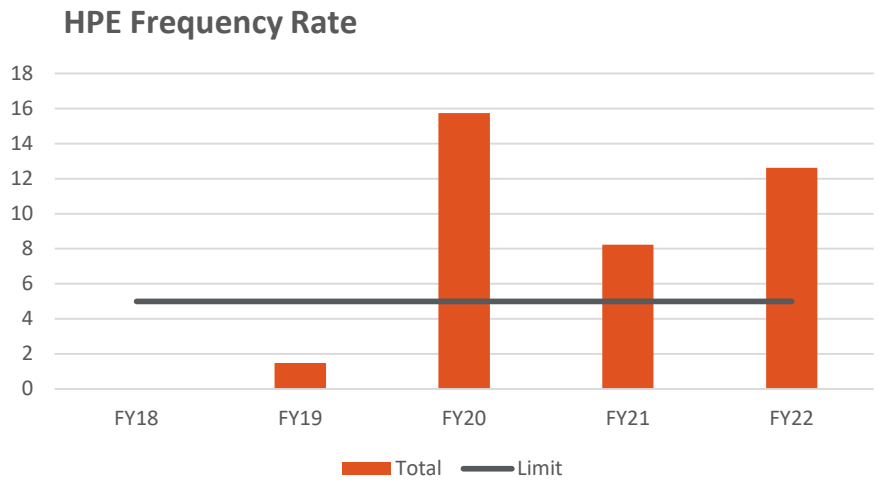
Worker health and safety

We collect occupational health and safety data to manage our health and safety performance. The two critical measures of our health and safety performance are:

- **high potential events incident frequency rate (HPEFR)**: High potential events include events of either an actual or potential catastrophic consequence. This is annualised against million hours worked to develop a rolling monthly rate.
- **total recordable incident frequency rate (TRIFR)**: Events which had an actual outcome of medical treatment injury, restricted work injury, or lost time injury. This is annualised against million hours worked and is a rolling monthly rate.

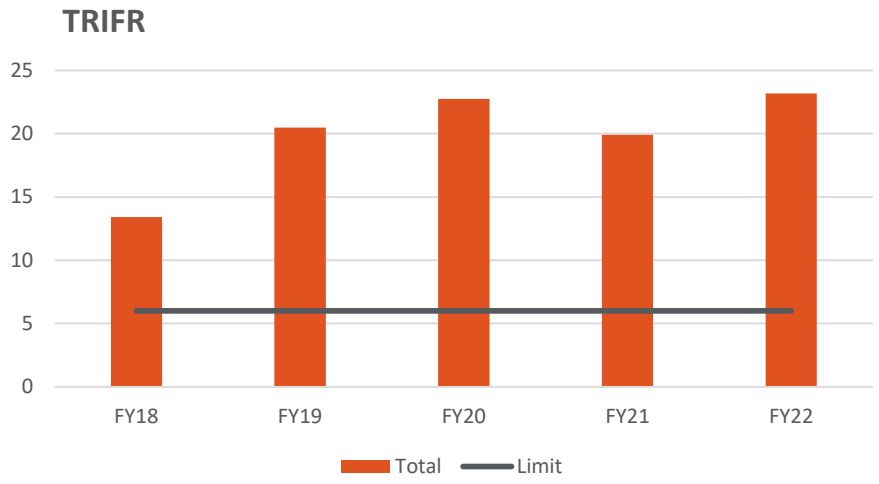
Our network had six high potential events (HPEs) reported in the previous 12-month period. Our rate is 12.29 compared with a limit of five. Two of the events related to public safety from the operation of our assets, with no harm occurring.

Figure 5.4: Group high potential events incident frequency rate



Our network had an injury rate in FY22 of 12.29, compared with a limit of six.

Figure 5.5: Group total recordable incident frequency rate (TRIFR)



Supporting initiatives

The key strategies and initiatives described below will help drive a stronger safety culture. Over time this will improve our TRIFR towards a best practice performance level.

- **Bow tie methodology**: Approach is applied to identify risks in our health and safety risk matrix. We utilise bow tie methodology to identify the causes and consequences of material events, which in turn create high and very high health and safety risks.
- **Assurance framework**: We have an assurance framework with regular monthly auditing and management safety leadership site visits. Elements of the audits include assessing for hazard and risk awareness, what the controls are, and how well this is accomplished.

To manage the risk that our assets pose to the public we have lifted our asset investment programmes and have a close focus on the timeframes for remediation of defects to ensure they do not fail in service and cause a public safety risk. This is further discussed in Chapter 9

A key strategy in managing public safety risk is education. This helps to raise awareness of the risks from electricity to a wide audience, from children to adults, homeowners to farmers to contractors. This includes providing:

- safety and general information and contact details on our website
- fault and emergency contact details in the phone book
- published safety information for distribution to customers
- safety advertisements in local media and social media
- public talks and presentations
- safety information at community events
- safety radio advertising in cooperation with our neighbouring network, Top Energy.

Specific warning notices are placed on certain network assets in public areas, e.g. ground-mounted distribution substations, pillars, zone substation security fences, etc.

Chapter 7 describes our broader approach to safety risk management.

5.3. Delivering for customers

Our electricity network provides an essential service to our communities. Understanding what matters most to our customers and their satisfaction with our services helps to ensure our service remains relevant for customers. This is a key commitment in our SCI and a key focus area of our asset management strategy.

We monitor customer satisfaction monthly and annually to gauge overall satisfaction for both residential and commercial customers.

5.3.1. Customer satisfaction targets

Our performance target for customer satisfaction is >85%. Our customers' views on our performance are collated via an annual survey of 400 customers across our network, conducted by an independent research company as described in Section 3.1.4.

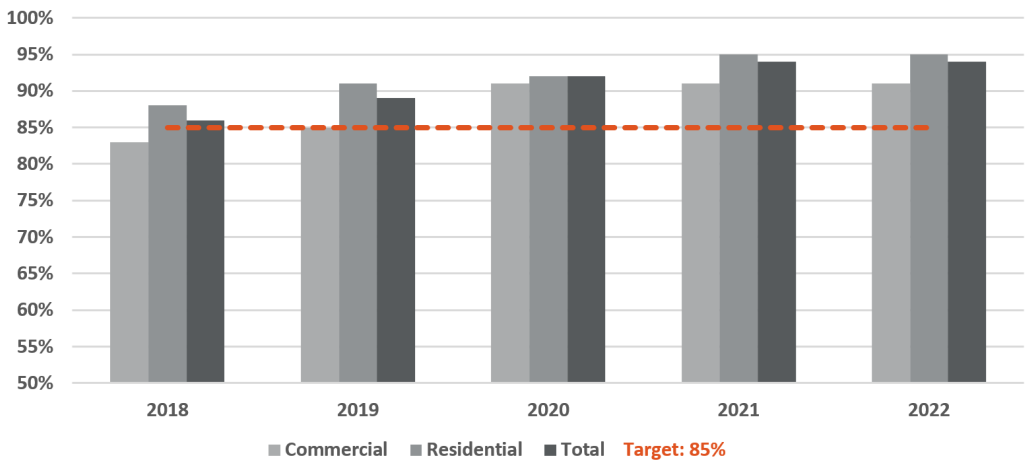
Table 5.2: Customer satisfaction targets

MEASURE	TARGETED PERFORMANCE
Customer satisfaction	At least 85% of customers indicate they are satisfied or highly satisfied (i.e. rating Northpower 7 to 10, out of 10)

5.3.2. Customer satisfaction performance

As depicted below, we consistently meet our customer satisfaction target of > 85%. The last annual survey showed our overall customer satisfaction is high – overall 94% of customers are satisfied or highly satisfied (an increase from 92% in 2020). This was made up of 91% of commercial customers being satisfied or highly satisfied and 95% of residential customers being satisfied or highly satisfied.

Figure 5.6: Customer satisfaction results



5.4. Environment and sustainability

Northpower is committed to being environmentally responsible. We recognise our role as kaitiakitanga, including the importance of being good stewards of the environment. A key objective is to ensure our organisation's operations do not cause harm to the environment.

Increasingly, in the context of climate change, we recognise the part we must play to support our Northland community's long-term adaptation needs and decarbonisation aspirations.

We are committed to being environmentally responsible. This is consistent with our purpose. Northpower's environmental management policy communicates our principal commitments to ensuring we do not cause harm to the environment.

- Sulphur hexafluoride (SF_6) is a potent greenhouse gas that is used as an interruption medium for switchgear. We are committed to minimising Northpower's SF_6 emissions, and we carefully monitor and report losses.
- We operate oil containment facilities. We have oil spill mitigation procedures and staff are trained in mitigating this risk. Our target of zero uncontained oil spills is the only prudent target we could have for this measure.

5.4.1. Environmental targets

Northpower has reported and monitored discrete adverse environmental impacts for many years. Reflective of a maturing approach, in 2023 Northpower determined our baseline emissions inventory and commenced monitoring of a suite of other environmental indicators to provide a clearer line of sight to environmental performance. In time, as baselines and trends are known, targets will be set to drive improvements.

Table 5.3: Northpower environmental targets[12]

PERFORMANCE INDICATORS	TARGETS
SF_6 losses (% of gas holding)	< 2%
Number of breaches/legislative non-compliance	0

5.4.2. Environmental performance

Improved environmental performance is underpinned by good information. we now track a comprehensive set of environmental indicators, a snapshot of which is included below. This focuses on the key contributors to our emissions profile (excluding line losses), that is, transport/fuel consumption and production of waste. This information will inform future initiatives, adding to the resource recovery programmes already in place that divert waste from landfill.

[12] These targets remain in place for the planning period, though they will be subject to periodic review.

Table 5.4: Environmental performance

MEASURE	TARGET[13]	2020	2021	2022
Electricity consumption (MWh/month)	TBC	-	47	33
Water consumption (m3/day)	TBC	-	8	8
Waste to landfill (tonnes per month)	TBC	16.59	19.90	14.70
Waste diverted (tonnes per month, % of total)	TBC	7.88	6.50 (33%)	4.57 (31%)
Concrete recovery (tonnes)	TBC	-	42	46
SF_6 losses, % of holding	< 2%	0.40%	0.12%	0.48%
Breaches/legislative non-compliance	0	0	0	0

Supporting initiatives

Some of our recent initiatives to improve our environmental performance include:

- development of further performance targets to monitor and reduce our emissions across the business
- commitment to a sustainable transition of our vehicle fleet that ensures no degradation of network performance and that is economically prudent. Our passenger fleet will electrify first, with field-based vehicles transitioning as viable, price-effective alternatives become available
- focusing on the up and down stream management of waste and the judicious use and phasing out of SF_6 insulated equipment (where practicable). While less significant in terms of impact, this rounds out our emissions reduction programme in the short term
- partnership with Digital Wings, a not-for-profit organisation that repurposes end-of-life electronics, redistributing them to deserving community groups. A large volume of our end-of-life electronics are now refurbished and redeployed.

5.5. Network performance

Northpower recognises that network performance is a priority for our customers. Ensuring a safe, reliable, and resilient network is a key focus area of our asset management strategy and electricity business plan.

In terms of network performance, our overarching aim is to achieve an appropriate balance between cost, risk, and the performance delivery to customers. We consider two main aspects of network performance: service reliability and power quality.

Service reliability

Reliability of supply is measured in terms of duration and frequency of interruptions per customer. The service our customers receive from the network is largely determined by the assets we use to deliver their electricity. We track network reliability using measures consistent with regulatory regimes in New Zealand and overseas (SAIDI and SAIFI, which

[13] We continue to collect performance data on these areas will develop a set of targets that we will work towards in the coming planning period.

are discussed further in the next section). We have also historically used 'faults per 100km' as an indicator of underlying network performance.

Power quality

Power quality relates to the voltage delivered to a customer's point of supply. Performance requirements are specified in the Electricity (Safety) Regulations 2010 and in industry standards[14]. Consistent with these, we target the following levels of power quality:

- **230V**: within ± 6% at point of supply (except for momentary fluctuations)
- **HV**: within ± 6% of the agreed supply voltage unless otherwise agreed (except for momentary fluctuations)
- **frequency**: is maintained within 1.5% of 50 Hz except for momentary fluctuations.

We manage the power quality received by customers through good network design, responsiveness to voltage complaints, and active monitoring of load throughout the network. We aim to provide quality supply to all customers within regulatory standards.

In addition to existing performance measures, planned improvements to outage management and asset management systems will provide an opportunity to extend the reporting of performance-related metrics.

5.5.1. Network reliability targets

Accurately forecasting future reliability performance is challenging as it is impacted by multiple factors such as asset condition, prevailing climate, new network configurations and technologies, and our capability to deliver our proposed interventions, including reactive maintenance. A number of these factors are beyond our direct control.

A number of measures are used to report our network reliability performance to stakeholders, including the Commerce Commission. The main measures are:

- SAIDI (System average interruption duration index)
- SAIFI (System average interruption frequency index).

SAIDI and SAIFI measure average length (duration) and average number (frequency) of outages, respectively, per customer per year.

Historically, our targets for SAIDI and SAIFI have been based on raw values, an approach that fails to account for the volatility caused by major weather events. As set out in our SCI, we have updated our reliability metrics to reflect the measures that would apply if we were subject to price/quality regulation under a default price-quality path (DPP). We have used the current default price-quality methodology (DPP3), which uses 10 years of historical performance to calculate normalised performance targets, consistent with the DPP methodology.[15]

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[14] Traditionally ECP36 has been used for standard harmonic level; however, AS/NZS 6100.3.6 is a more recent standard and is regarded as a better and more appropriate standard/code for the distribution industry.

[15] Consistent with the DPP methodology, calculations for unplanned SAIDI and SAIFI are normalised to reduce the impact of extreme events in order to provide a better view of the underlying performance.

In addition to SAIDI and SAIFI, we have a target for average fault rate performance. Fault rates are based on the number of faults per 100km of network length for both the overhead and underground networks.

Our forward performance metrics and targets are shown in the table below.

Table 5.5: Northpower electricity network reliability forecasts[16]

MEASURE	TYPE	FY24	FY25	FY26	FY27	FY28
Network interruptions SAIDI minutes	planned	162	162	162	162	162
	unplanned	93	93	93	93	93
Network interruptions SAIFI	planned	0.72	0.72	0.72	0.72	0.72
	unplanned	2.28	2.28	2.28	2.28	2.28
Average faults per 100 km		≤ 10	≤ 10	≤ 10	≤ 10	≤ 10

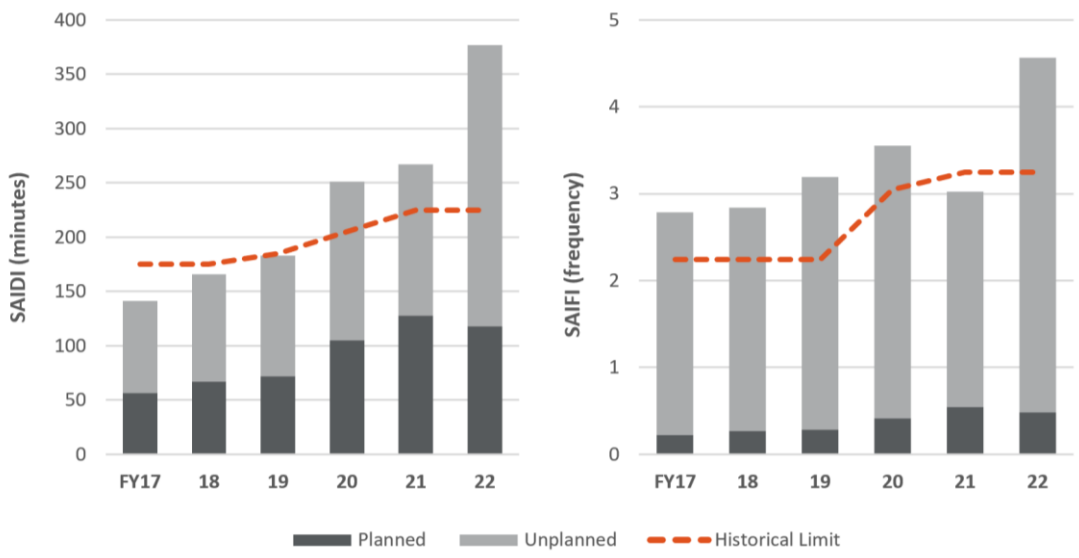
5.5.2. SAIDI/SAIFI performance

Total SAIDI/SAIFI

Prior to the adoption of a DPP3-based normalised approach, performance targets were reviewed annually and raw values established for both planned and unplanned SAIDI/SAIFI. The following charts compare the total raw (non-normalised) performance with these targets.

In most years a reasonably strong correlation exists between SAIDI and SAIFI for both planned and unplanned outages.

Figure 5.7: Total raw SAIDI and SAIFI versus limits



16 These targets remain in place for the planning period, though will be subject to periodic review including when the DPP is reset.

Historically, network reliability has generally been achieved against targets. In the last three years, however, performance targets have been exceeded due to unplanned outages on the subtransmission network caused by a growing backlog of vegetation clearance, a major lightning strike in FY21, and a major substation fault in FY22. Three major weather events in FY22 contributed over 80 SAIDI minutes. We have also seen an ongoing rise in the number of outages caused by third-party events. Actions intended to mitigate the impact of unplanned outages are outlined in the following section.

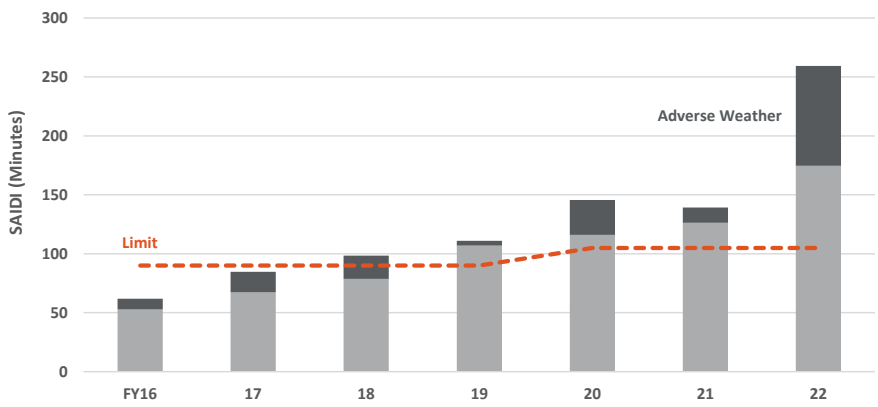
Planned SAIDI and SAIFI have risen in recent years in line with an increase in work volumes undertaken to address a backlog in defect remediation. After reaching a peak in FY21, planned SAIDI has begun to decline, largely as a result of efforts to increase the amount of planned work performed under live line conditions, and the introduction of a formal SAIDI mitigation plan and options analysis to manage outages above certain thresholds. However, planned SAIDI is expected to rise again in line with a planned increase in asset renewal over the planning period.

Unplanned outages

Unplanned outages have trended upwards since FY16, due mainly to the impact of vegetation and equipment faults on the subtransmission network, major weather events, and an ongoing increase in the number of car versus pole incidents.

The number and frequency of adverse weather events continue to have a significant impact on the raw values. The impact of adverse weather is illustrated in the following chart.

Figure 5.8: The impact of adverse weather events on unplanned SAIDI



In addition to the impact of adverse weather events, the negative variance in the three years from FY20 was caused by rare events on the subtransmission network. These included two vegetation faults, a lightning strike on the single 33kV line to Mangawhai, and a substation bus fault in FY22.

While the number of unplanned outages on the network are expected to fall as a result of initiatives designed to improve reliability, we do not expect these benefits to be fully reflected in unplanned SAIDI and SAIFI. Factors that are likely to offset benefits arising from reliability improvement programmes include the following:

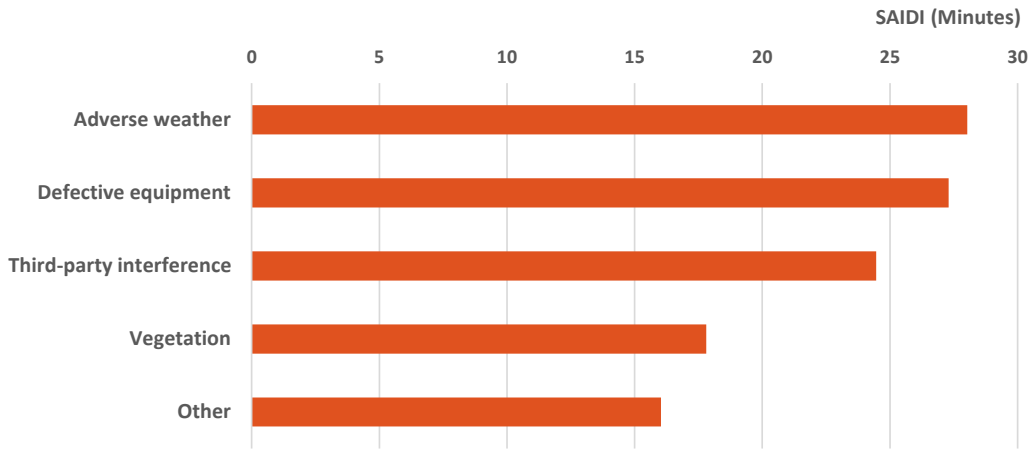
- the recent introduction of a fault restoration policy designed to minimise risk to public safety, increasing the duration of some unplanned outages. This is the latest in a series of safety-related initiatives that have contributed to an increase in the average duration of an unplanned outage since FY17
- an ongoing rise in the number of third-party interference incidents in line with the rate of population growth and traffic density
- an expected increase in the number and intensity of major weather events associated with climate change
- new rules to be introduced by the Commerce Commission for counting successive interruptions are expected to impact customer interruption statistics.

Major causes of unplanned outages

Expressed as an average over the last five years, 86% of all SAIDI can be attributed to one of four high-level causes: adverse weather, defective equipment, third-party interference, and vegetation. Other minor causes represent 14% of total unplanned SAIDI and include lightning, adverse environment, human error, wildlife, and outages with an unknown cause.

The following charts illustrate the relative impact of the four major causes of unplanned outages on the distribution network and the trend over time.

Figure 5.9: Average unplanned SAIDI by major cause (HV) from FY18 to FY22

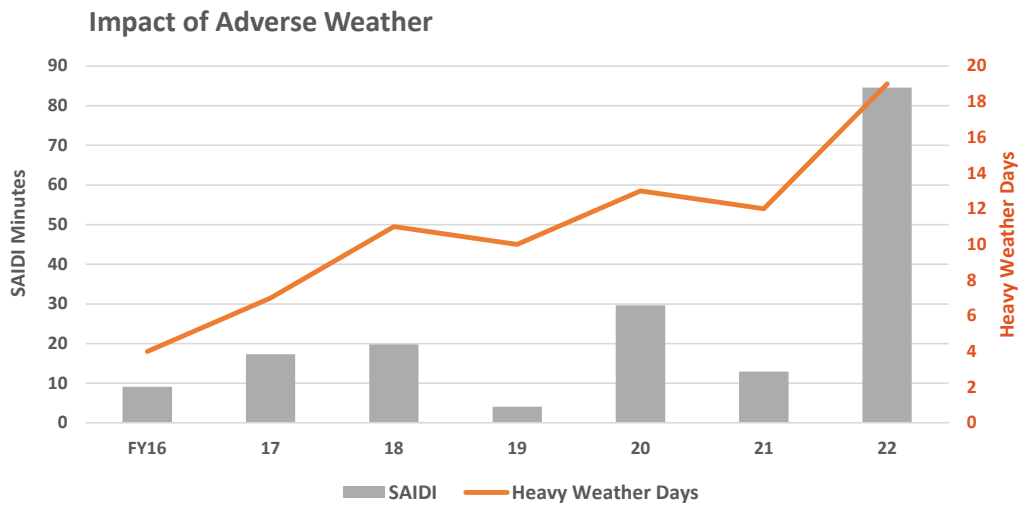


Adverse weather

While major weather events are infrequent, they produce major fluctuations in SAIDI and can have a significant impact on the frequency and duration of unplanned outages.

The following chart illustrates the rise in the number of heavy weather days that have caused outages. These are overlaid on the trend in SAIDI caused by adverse weather.

Figure 5.10: Adverse weather



The chart highlights an uptick in the number and intensity of adverse weather events contributing to unplanned SAIDI. The large spike in FY22 was caused by a small number of intense storms including a cyclone.

We expect this trend to continue due to the impacts of climate change. These events will continue to challenge the resilience of the aging network in the medium to long term.

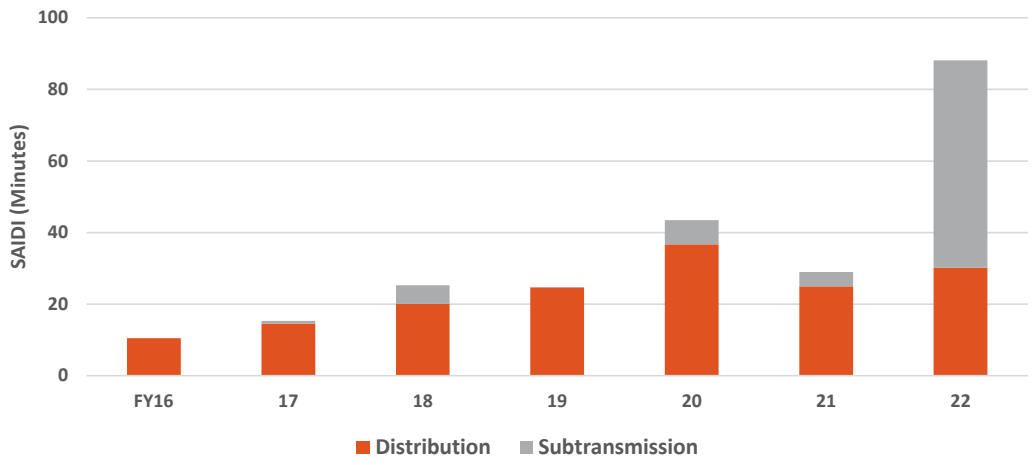
We have introduced a number of strategies designed to mitigate storm impacts and increase the resilience of the network to adverse weather. These include:

- the introduction of new design standards for network assets aimed at reducing the risk of failure related to wind damage, and increased corrective maintenance expenditure on defect remediation
- better identification and management of fall-zone trees and reduction of wind-blown vegetation debris
- increased focus on the subtransmission network to ensure the backbone of our network is increasingly resilient to weather-related events.

Defective equipment

The following chart illustrates the trend in unplanned SAIDI caused by defective equipment.

Figure 5.11: Defective equipment SAIDI



Defective equipment SAIDI on the subtransmission network is characterised by numerically few outages, with high SAIDI impact and a large number of customers affected. The criticality of this network has been recognised by a significant uplift in investment in replacement programmes for end-of-life subtransmission assets.

A number of initiatives have been put in place to address reliability of the distribution network. Defective equipment SAIDI has begun to trend down from a peak in FY20 as a result. These initiatives have included:

- the introduction of a revised inspection standard for defect classification
- enhanced monitoring to ensure priority work is delivered within specified time frames
- increased corrective maintenance budgets committed to defect remediation
- full structure maintenance and acoustic testing of substation assets.

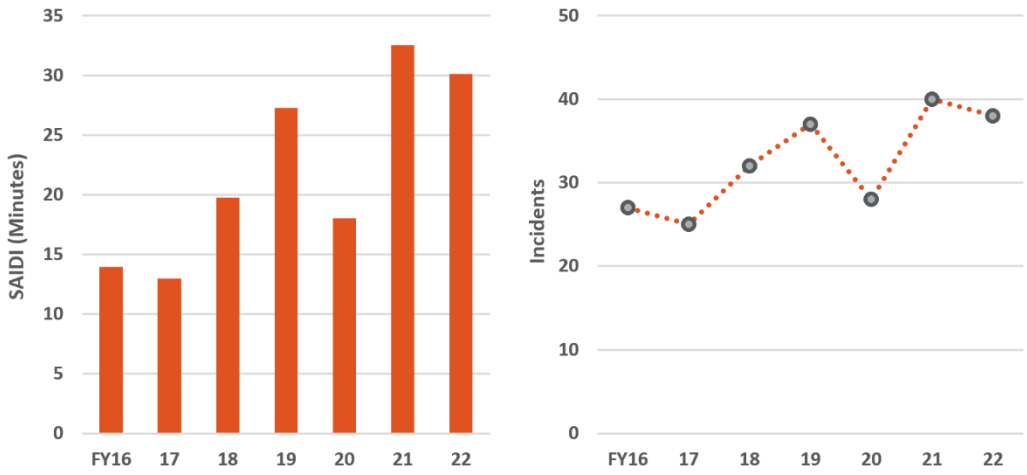
Increased resourcing has enabled a renewed focus on data analysis and modelling, designed to identify high-risk areas of the network and optimise asset replacement at these locations. Data-driven models have also been introduced to drive asset renewal forecasts. To realise the full benefit of these models, a ground-up review of information models and data capture is planned for 2023.

As a result of current and new initiatives we expect unplanned SAIDI caused by defective equipment to stabilise and begin to trend downwards over the planning period.

Third-party interference

The number of outages caused by vehicles hitting poles has continued to trend upwards and they feature significantly in unplanned SAIDI statistics. This appears to be an industry-wide trend.

Figure 5.12: Third party interference SAIDI



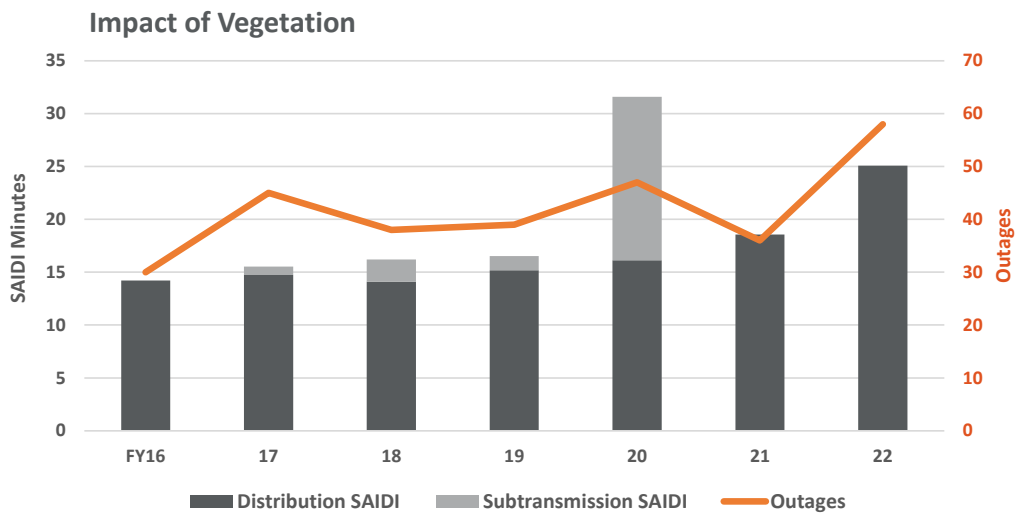
We routinely review pole locations when a vehicle collides with a pole to identify how we can reduce the location's vulnerability to a vehicle-related event. Options include relocation of the network or undergrounding the relevant network where this can be justified.

However, an underlying driver for this type of outage is the population growth, particularly in the urban areas where there has been a major increase in traffic density in recent years. This trend shows no sign of slowing and we expect growth in the number of vehicles on our roads to be reflected in the number of vehicle versus pole incidents.

Vegetation

The following chart illustrates the number of outages over time caused by vegetation overlaid on SAIDI, split by subtransmission and distribution.

Figure 5.13: Vegetation SAIDI



Apart from two major outages caused by vegetation on the subtransmission network in FY20, SAIDI has remained reasonably consistent until FY22.

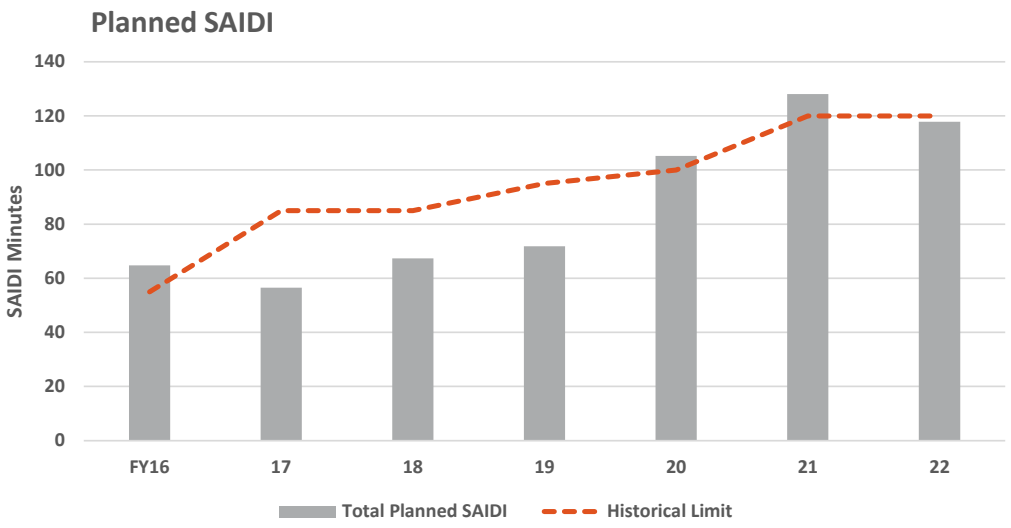
In FY22 vegetation SAIDI increased by 35% on the previous year. This was due primarily to unseasonal weather conditions that brought prime growing conditions, increasing vegetation amounts, and a prevalence of easterly winds which can lead to increased tree failures compared with more typical westerly winds.

Helicopter surveys and line patrols of subtransmission networks focus on identifying risks from fall-zone trees and wind-blown vegetation debris. We use a risk-based approach to reduce the impact of vegetation on our network, and actively engage with landowners to get their agreement to remove vegetation that provides an elevated risk of interference with the network.

Planned outages

The chart below shows planned SAIDI performance as they relate to historic targets for this measure.

Figure 5.14: Planned SAIDI vs historical limit



We have progressively lifted our planned SAIDI targets since 2017 to reflect an expected increase in planned works. However, resource constraints and work deferrals meant that we were below expected levels during the three-year period from FY17 to FY20. The uplift in FY20 reflects increased expenditure on backlogs and the beginning of our renewals uplift.

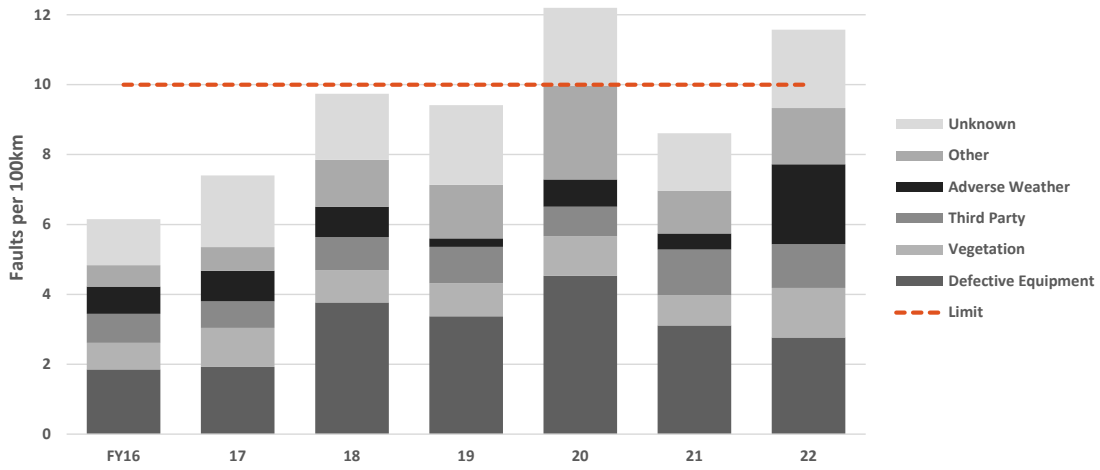
While planned SAIDI declined from a peak in FY21 due in part to initiatives designed to minimise the impact on customers, the overall increase from FY20 reflects a continued uplift in the amount of planned work carried out. This trend is expected to continue in line with the forecast increased investment in asset renewal.

An uplift in recent years in planned SAIFI reflects the same drivers as those for planned SAIDI – an increase in our planned work programme, an ongoing focus on defect remediation, and targeted end-of-life asset replacement.

5.5.3. Fault rate

The following chart illustrates the seven-year trend against target for faults per 100km of network. The four major contributing causes (defective equipment, adverse weather, third party, and vegetation) are shown separately, while the balance (wildlife, lightning, adverse environment, and human error) have been combined in order to present a clearer picture. Note, fault counts may not reflect the relative contribution of each cause to SAIDI.

Figure 5.15: Faults per 100km due to main causes



Historically the major contributor to the fault rate has been equipment failure. This continued to trend upwards to a high point in FY20 but has since begun to fall as maintenance budgets and resourcing have increased. These have been directed at improved identification and prioritisation of defects enhanced by active monitoring of resolution time frames.

Negative variances in FY20 and FY22 were largely due to a spike in the number of lightning storms and several major weather events respectively.

Faults from other sources have remained fairly consistent in recent years.

We anticipate the number of faults on the network will start to reduce marginally from FY23 as targeted investment programmes begin delivering further reliability improvements. These programmes, which are covered in Chapters 8 and 9, include:

- a programme to improve feeder performance and visibility of the network by installing new switches with fault passage indication in strategic locations, and replacement of existing manual switches with automated switches
- addition of N-1 security on critical subtransmission circuits
- significant uplift in investment in asset renewal, driven by data analysis and modelling
- increased use of destructive sampling of end and near end-of-life assets to better understand the condition of the network
- a move away from the traditional cyclical, feeder-based vegetation management approach to a risk-based strategy supported by rapid inspections.

An outage management system is planned as a second phase of the ADMS rollout. Combined with a ground-up review of our existing information model and advanced analysis

toolsets, this will provide a platform for engineering staff to better understand the root causes of asset failures and address underlying failure trends on the network.

5.6. Supporting communities

As a trust-owned business, we have a strong focus on ensuring equitable and sustainable outcomes for the communities we serve. As discussed in Chapter 2, our customers have told us in our annual survey that fair pricing and cost efficiency are their top priorities. We are committed to keeping our service costs low and actively look for efficiencies in the way we invest in and operate our network.

Recognising this, we are developing a set of performance indicators to help ensure we continue to deliver cost-effective services to our customers.

5.6.1. Delivering cost-effective services

Service affordability is impacted by the level of asset investment and the operational costs required to provide our network services to customers.

Although we have not set specific targets around affordability, we ensure that our operational expenditure and network investments are cost-effective through strict investment planning processes, internal challenge, and governance oversight. We are committed to continually improving our asset management capability to further understand our network assets, improving our investment decision-making and our ability to deliver our services more affordably.

Consumer distributions

We have a strong focus on ensuring equitable and sustainable outcomes for our consumer owners. Our trust ownership ensures the profits we make are returned to the communities we serve. Since 1993, this arrangement has delivered more than $264 million to our connected electricity consumers.

Fair pricing

We are increasing our focus on ensuring our pricing is fair, transparent, and equitable for all consumers. We seek to implement fair pricing for all users of our network and make sure our pricing is well understood by customers.

To maintain equitable pricing, our policies focus on those customers that drive network costs paying their fair share of those costs. Two key elements include:

- **capital contributions**: our new policy means fairer allocation of costs to those requesting investments (developers). On balance, those driving growth on the network will largely fund the required investments, meaning that total costs for consumers will be lower over the long run.
- **pricing reform**: moving towards more cost reflective pricing will ensure customers pay a fairer proportion of the cost of the service they receive. For some low-income, high-use households this will reduce their line charges. By adopting time-of-use charging, we aim to signal times of peak usage, to encourage consumption outside the peak. Over time this reduces the need to invest in more capacity.

Energy education

Our ongoing energy education programme (see Chapter 2) helps our customers get the most from their energy choices. We have also put together a consumer outreach programme to help communities by providing practical energy-saving advice and assistance to reduce total electricity costs.

We are working with community partners to reach households in need, delivering personalised advice and support to households across the Whangārei and Kaipara districts. This includes practical help through home energy assessments, helping customers find the most suitable retail plan, and providing free LED lightbulbs and low-flow showerheads.

Efficient works delivery

Efficient network expenditure does not mean simply minimising short-term expenditure as we need to consider whole-of-life costs, including the financial impacts of poor performance. To maintain safe and reliable services for customers we must continue to invest in network assets at appropriate levels and to make sure that we maintain these in a fully functional state. This includes testing our investments to ensure major new capacity upgrades provide the lowest cost/best outcome for consumers. The focus is on ensuring we achieve maximum long-term benefit from our investments and reduce whole-of-life costs across our network.

Network utilisation[17]

An important indicator of the efficiency of our investments and network operations is the level of utilisation of our assets. Our strategy aims to ensure maximum value from our investments by ensuring good design and lifecycle management practices. We are developing a set of targets that will help to target ongoing, efficient levels of utilisation.

We have calculated 33% utilisation of our distribution transformers, against an industry average of 28%, indicating above average utilisation. LV monitoring devices are being deployed on selected distribution transformers which are used to record actual utilisation. This will help us improve utilisation across the network.

5.7. Capability

Good practice asset management helps us deliver a cost-effective, safe, reliable service to our customers. For this we need to continuously improve and develop our people, our systems, and our processes.

Since publishing our last full AMP in 2021, we have increased our efforts to refine and update our approach to asset management. It has become apparent that our asset management practices, while fundamentally sound, need to evolve, given increasing investment needs and increasing uncertainty about future energy markets.

We have begun to develop a set of targets to measure our progress in this area. These are set out below.

[17] We calculate network utilisation as the maximum demand across all distribution feeders on the network, divided by the distribution transformer capacity on the network.

Table 5.6: Our capability targets

PERFORMANCE INDICATOR	TIMING
AMMAT score of 3 (independently verified)	2025
ISO gap analysis to inform next full AMP	2025
Develop an asset management competency framework	2024

5.7.1. Capability performance

Having appropriate levels of capability is critical for effective asset management. Our people need to have the right capabilities to manage long-life electricity assets safely and effectively. This is particularly important as the electricity sector evolves.

Asset management capability includes processes, systems, tools, and knowledge that we employ to deliver our asset management activities. Our AMMAT[18] assessment discussed in Section 6.5 sets out our self-assessment of our asset management maturity. Our assessment has an overall score of 2.0, which is lower than our assessment of 2.8 in our 2021 AMP. This scoring reflects a more robust, systematic assessment of our full asset management system. This forward-looking review assessed current capability against best practice asset management and the ongoing need for continuous improvement to address the challenges and opportunities the business faces.

We have been forthright in our AMMAT assessment of our capabilities, strengths as well as shortcomings, and we recognise that the discipline of asset management continues to evolve and improve over time.

We continue to reposition and enhance our asset management approach. We have recognised that this is a critical enabling step, given the increasing levels of expenditure required on our networks, and the need to manage this investment prudently. We have invested heavily in capability and support to enable us to deliver what has been a material shift in approach. However, there is considerably more yet to do.

Supporting initiatives

Over the next five years we will move to fully embed and leverage changes in our asset management approach to ensure ongoing prudency of investment and efficiency of spend. This will include fully documenting our approach through a formal shift to the ISO 55000 framework and developing the level of advanced asset management capability necessary to be able to deploy and leverage more advanced techniques.

Recognising the need for improvement in our asset management capability and the challenges that we and the wider electricity distribution sector face, we have developed a continuous improvement programme. This programme is set out in Section 6.5.2.

[18] Asset management maturity assessment tool (AMMAT). This is discussed in Chapter 6.

5.8. Future readiness

As discussed in earlier sections, we are taking action to ensure we are ready for the evolving energy market and the increasing use of technologies that will have material impacts on energy use and flows on our network. By doing so we will continue to provide services that will meet our customers' energy needs reliably and efficiently, now and in the future.

As more electric vehicles, solar panels, and batteries are deployed, our network will need to handle two-way power flows and increasing voltage fluctuations. Developing good technical standards and ongoing network monitoring is critical to keeping our costs down and ensuring continued reliability of our supply to customers.

We are continuing to develop network standards for service connections and customer agreements, as well as our operations manuals, capital contributions, and asset management-related standards to adapt to the changing electricity network. This means striving to keep connection standards simple and future-proofed, ensuring pricing is fair and equitable across all customer groups, and working with local partners to enable new solutions that benefit our customers.

5.8.1. Future readiness targets

These targets provide our teams with clear guidance on the asset management aspects we must focus on to ensure we are ready to enable our customers' future energy choices.

We are developing a set of targets to measure our progress in this area. These are set out below. We will continue to develop these targets as we progress this work further.

Table 5.7: Our future readiness targets

PERFORMANCE INDICATOR	TIMING
Build greater visibility and modelling of our low voltage network to enable proactive management of LV constraints	FY26
Continue roll out of LV monitoring devices at a rate of 20 devices per year	Ongoing
Deploy new AMIS system to enable better data capture and analytics	FY25
Gain insight to customer usage and impacts of EV charging through half hour data from retailers	FY24
Continue to work closely with PV installers and solar / wind farm operators to enable DER on the network, adapting as increasing large generators connect	Ongoing
Deploy ADMS module to manage large scale DER generation with the connection of the first large scale solar farm	FY24

These performance indicators have been developed recently and we are yet to begin formally tracking our performance against them. We expect to report on our progress in this area in our next AMP.

Supporting initiatives

As society changes and technologies develop, standards need to evolve. We are actively participating in a number of technical advisory groups, examining, and developing new standards and guides for EV charging, earthing, integration of inverters, and voltage regulation.

Our efforts to improve our performance in this area are supported by the following initiatives:

- implementation of ADMS phase 2 for HV visibility of our network
- increasing digital and analytical capability
- LV and HV visibility (short term) and LV control (medium term) of our network
- monitoring and publishing hosting capacity for distributed generation (DG)
- enabling the connection of large-scale DG on our network
- monitoring evolving energy market developments and opportunities for improving value for our consumer owners
- developing and implementing a remote area power supply (RAPS) alternative for remote areas of our network where this is the most cost-effective option
- making timely, prudent investment decisions that meet the demand for growth and build the enabling foundations for an active modern network
- adopting new technology and methods where proven to add value
- developing and implementing supply options for remote areas of our network
- evaluating non-network alternatives to address constrained areas of our network
- providing pricing signals to enable customers to make informed decisions about their energy use
- developing flexibility services and pricing options for customers
- providing our customers with easy to understand information on making wise energy choices to save money on their total energy, as well as educating customers on future energy choices with non-biased information around PV and EV.

Chapter content

6 Approach to Asset Management

6. APPROACH TO ASSET MANAGEMENT

6.1. Introduction

This chapter explains our overarching approach to managing the assets on our electricity network.

Effective asset management needs to consider the full asset lifecycle. This includes initial development investments, maintaining performance and safety during an asset's life, managing cost of ownership, and efficiently renewing and disposing assets at end-of-life.

Asset management at Northpower uses a holistic approach that considers the full lifecycle of an asset. This includes the creation of the asset, operation and maintenance over its lifetime, and decommissioning and disposal at end-of-life. We have adopted a typical staged approach that governs the activities we adopt to manage assets over each stage of their lifetime. When managing our assets, we use a hierarchy of asset portfolios and asset fleets to help ensure consistency in our approach.

Delivering for our customer owners requires effective investment decision making. Our decision-making approach takes a long-term view, accounting for customer needs, whole-of-life costs, and asset performance. We continue to consider the evolving nature of the electricity industry, including what future networks may look like, and the associated network services and asset solutions.

Finally, this chapter discusses our asset management capability, including our plans to improve our approach and competency in support of our future work plans.

6.2. Lifecycle approach to asset management

Our lifecycle-based asset management approach supports our strategy to provide a safe, affordable, and reliable electricity supply to our customer owners.

Our asset management practices aim to prudently manage the performance of our assets between the time of commissioning and eventual renewal.

As depicted to the right, our approach to asset lifecycle management is based on four stages.

The four stages are described below, with further detail provided in the referenced chapters.

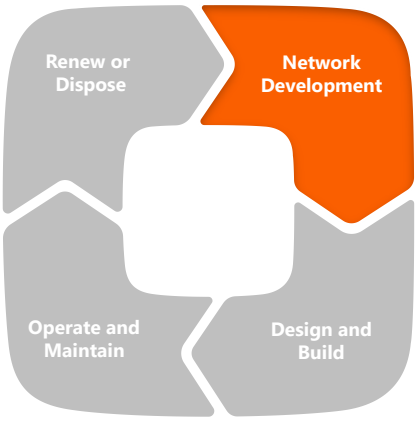
- **Network development**: covers the creation of new or enhanced assets. It spans the identification of the initial need, assessing options, and preparing conceptual designs. This stage is described in more detail in Chapter 8.
- **Design and build**: this stage includes detailed design, tendering, construction, project management, commissioning, and handover of new assets to our operational teams. This stage is discussed later in this chapter.
- **Operate and maintain**: covers the operation and maintenance of our network assets. These activities aim to ensure safe and reliable performance over the expected lives of the assets. This is described in more detail in Chapter 9.
- **Renew or dispose**: covers how we decide to renew and/or dispose of assets. Generally, a decision to renew or dispose of an asset is needed when it becomes unsafe, obsolete, or would cost more to maintain than to replace. This stage is discussed in Chapter 9.

6.2.1. Network development

We use the term network development to describe capital investments that increase the capacity, improve the security and reliability of the network to acceptable levels.

These investments help ensure our assets continue to operate within appropriate performance limits and provide an appropriate level of service to customers.

We need to maintain appropriate levels of security and performance to meet growing demand and to provide flexibility to customers wishing to connect.



Network development typically responds to four key investment drivers:

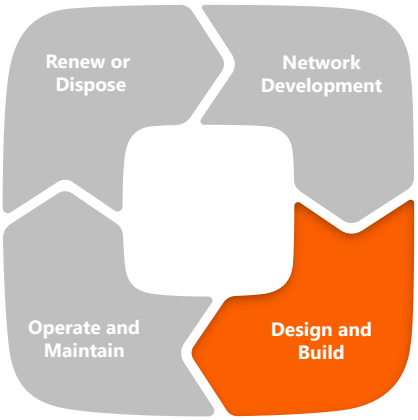
- **Growth and security**: network investment to ensure demand on the network is met, while maintaining our levels of security of supply.
- **Reliability and quality of supply**: targeted network investment to improve reliability and quality of supply. This includes investments to improve feeder performance by installing remote-controlled devices and increasing back-feed capacity.
- **Consumer connections**: network investment to enable new customers to connect to our network.
- **Network transformation**: network investment to meet the evolving needs of our customers and manage constraints arising from changing network behaviour.

Chapter 8 sets out how we will invest to meet these drivers over the AMP planning period.

6.2.2. Design and build

Delivering for customers will require a significant level of network investment over the AMP planning period. To support this increased level of investment, we need to maintain effective design and build capability. This includes the capacity and capability of both our field delivery teams and our internal planning capability. We also need to ensure that sufficient plant and materials are available.

To support this we have a range of applicable network standards and specifications, which are set out below.



Safety in design

We apply safety in design principles to ensure our network is designed so it is safe to build, operate, maintain, and decommission. Our safety in design framework is adapted from the Electricity Engineers Association (EEA) guide for safety in design. The main objective of the framework is to ensure that our design process does not introduce new hazards, as well as minimising current hazards during the construction, operation, and maintenance phases of an asset's lifecycle.

Design and technical standards

To manage the safety, cost, efficiency, and quality aspects of our network we standardise network design and work practices where practicable. The use of standardised designs can lower costs by reducing spares holdings and simplifying maintenance procedures.

Our technical standards apply to Northpower staff and authorised service providers working on our network. They reference the relevant codes of practice and industry standards as appropriate. We engage external consultants to provide designs for our critical assets, including zone substation design.

Equipment specifications

We aim to adopt standardised equipment for construction on the network. We have developed specifications detailing accepted performance criteria for significant equipment on our network (e.g., power transformers, switchgear). New equipment must conform to these standards. We maintain a list of approved equipment for use on the network, which meet our quality requirements. New equipment types are assessed and often tested before being approved on the network.

Documentation control

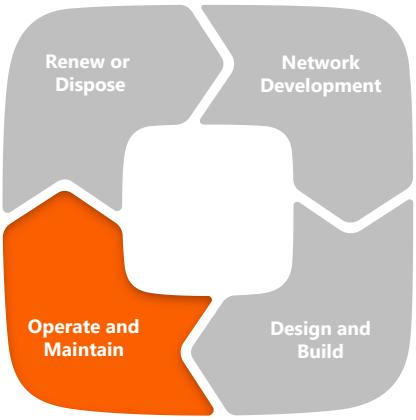
We ensure our documentation and drawings are maintained as accurately as possible with changes managed through a change control process on our quality management system. Our network information team is responsible for maintaining and processing changes to these controlled documents using a process set out in our document control standard.

6.2.3. Operate and maintain

Effective asset management uses appropriate operations and maintenance over an asset's lifecycle.

Following commissioning, assets are put into service and maintenance and operation of the asset begins and continues until it is renewed or disposed of. These activities often vary over the lifecycle of an asset, e.g., increasing repairs as an asset ages.

The operate and maintain stage includes network operations, maintenance, vegetation management, and spares management.



Overview of operations

Network operations refers to the range of activities necessary to ensure the day-to-day safe and reliable control and management of our distribution network. The primary role of network operations is to provide a reliable supply of electricity to our customers by operating the network in a way that ensures we meet network, operational, safety, and asset performance objectives on a 24/7 basis. This is achieved through system monitoring, switching and load control, fault response coordination, and providing contractors access to the network for works required to develop and maintain the assets. It includes the use of:

- **equipment operating instructions**: to ensure safe operation of our network we have operational instructions covering the different types of equipment on our network. We create new instructions for new equipment introduced onto the network.
- **operating standards**: to ensure our network is operated safely we use standards related to the release of network equipment, commissioning procedures, system restoration, and access permit control.

Overview of maintenance

Maintenance is the care of assets to ensure they provide the required capability in a safe and reliable manner throughout their lifetime. It involves monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring the condition of the asset, if renewal is not the optimum intervention. Feedback from maintenance activities is used to improve our asset standards and planning processes, as well as to inform our Capex renewals programme.

We manage and organise our maintenance work into three network Opex portfolios:

- **preventive maintenance**: routine maintenance activities including testing, inspections, condition assessments, and servicing
- **corrective maintenance**: primarily involves remediating defects, by replacing components or minor assets, or undertaking repairs
- **reactive maintenance**: responding to faults and other network incidents. This may involve making a situation safe until a full repair is scheduled or undertaking the repair.

Chapter 9 provides more detail on our approach to maintenance and sets out our planned expenditure for the 10-year AMP period.

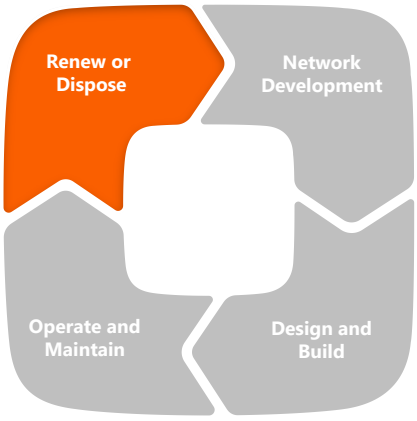
Vegetation management

Vegetation management is used to keep trees clear of overhead lines. This is necessary to minimise vegetation related outages and meet our safety and statutory obligations. Left unchecked, vegetation can have a significant impact on network reliability and public safety. The main vegetation management activities are inspections to determine the amount of work required, liaison with landowners when work is required, and subsequent follow-up to undertake tree trimming and removal.

Chapter 9 provides more detail on our approach to vegetation management and sets out planned expenditure for the 10-year AMP period.

6.2.4. Renew or dispose

As assets deteriorate, they eventually reach a state where ongoing maintenance to keep them safe and serviceable becomes ineffective or uneconomic.



Asset renewal is the replacement of ageing, damaged, or underperforming assets, or the refurbishment of existing assets to extend their useful life or increase their service potential.

Asset disposal follows the decision to remove an asset from our network, either because it is being replaced or has become redundant.

Refurbishment and replacement of assets are used to manage asset condition, safety risk and network performance, resilience, obsolescence, and to meet regulatory and legislative requirements. Our approach to renewal varies by asset fleet and, in some cases, there will be a range of risk reduction options to consider.

Renewal forecasting

Our asset replacement decisions are based on balancing several considerations, including the need to provide a safe, resilient, and affordable electricity supply. We take a balanced approach and consider whether continued maintenance is economic, asset criticality, and the potential health, safety, and environmental risk, along with the impact on reliability.

Our renewal expenditure is forecast in two ways:

- **volumetric forecasting**: for large volume fleets we use a replacement expenditure (Repex) forecasting technique to forecast replacement volumes over time. These are combined with P50[19] unit rates to forecast expenditure. The individual assets are then identified for replacement through our inspections and defect management approach.

[19] A P50 cost is an estimate of a cost based on a 50% probability that the cost will not be exceeded.

- **identified projects**: for lower volume fleets (typically with higher value assets) we plan on the basis of individual projects using asset condition (visual inspection and test data) and criticality, as well as consideration of other factors such as obsolescence, type issues, and environmental considerations. These projects are scoped and costed using a customised estimate.

Our asset management approach differs depending on the asset class and what asset condition information we currently hold. Our current approach is as follows.

- High-value, critical substation assets that have a high consequence of failure are replaced based on condition assessments and prioritised based on criticality. Robust, regular inspections feed into regularly updated condition assessments.
- Distribution overhead assets (e.g., poles, crossarms, insulators) are inspected regularly and replaced once they pose a risk to reliability, public safety, or the environment.
- Our buildings are inspected regularly, maintained, and repaired when required.

Our assets are generally planned for replacement when our asset health deteriorates beyond acceptable limits. Our visual inspection and test regimes ensure that the condition of our assets is monitored and that they are maintained or replaced prior to failure. The approach differs across different asset classes but replacement is generally planned in two ways:

- **defect management**: high-volume asset replacements are planned using our defect management approach. When an asset inspection identifies that an asset meets criteria for replacement, as set out in our defect management standard, a defect is raised and replacement planned before asset failure.
- **identified replacements**: our asset planning team review our visual inspection and test data as well as other inputs, such as obsolescence and industry experience, to identify and plan replacements to manage asset failures.

Asset criticality is considered generally in both our defect management and identified replacement approaches. Assets that are deemed to have a higher consequence of failure, through network disruption, environmental, safety, or reputational lenses, are prioritised for replacement over those that have a lower consequence of failure.

Chapter 9 discusses our asset management approach for each asset class in more detail.

Asset disposal

We are committed to disposing of our assets safely, in a way that minimises environmental impact and complies with all legislative and local authority requirements. This includes the disposal of redundant assets, equipment, and hazardous substances, while ensuring that materials such as oil, lead, PCBs, and asbestos, which may cause harm, are disposed of appropriately. We seek to recycle materials where practical.

6.3. Asset portfolios and fleets

When managing our network assets, we use a hierarchy of portfolios and fleets. The asset fleets forms the basis of our asset intervention strategies, which are then organised into a set of portfolios.[20] The hierarchy reflects the way we manage our network assets and how we plan our investments. Our portfolios and the fleets within them are set out in Table 6.1.

Table 6.1: Mapping between our asset portfolio and fleets

PORTFOLIO	FLEET
Overhead lines	Conductors
	Poles
	Crossarms
Substation equipment	Indoor switchgear
	Outdoor switchgear
	Substation power transformers
	Infrastructure and facilities
Underground cables	Subtransmission cables
	Distribution and low-voltage cables
Distribution equipment	Distribution transformers
	Ground-mounted switchgear
	Low-voltage distribution units
	Pole-mounted switchgear
Secondary systems and other assets	Protection systems
	Auxiliary power supply systems
	Load control
	SCADA system
	Automation and control systems
	Communications

Chapter 9 explains our day-to-day approach to managing the above portfolios and fleets.

6.4. Asset management decision-making

Asset management decision-making refers to the system of roles, responsibilities, authorities, and controls that support our asset investment decisions. This section explains our approach to these decisions and the governance processes used. This builds on our descriptions of organisational structure and main governance levels in Chapter 2.

[20] The portfolios differ slightly from the asset categories specified in information disclosure.

Asset management decision-making occurs at various levels in our organisation – from our Board through to our planning and delivery teams. The Northpower Electric Power Trust maintains a strong, structured engagement with Northpower's Board, which is responsible for ensuring investment focus and business performance are delivered in line with the trust's expectations. Investment decisions take place within a system of responsibilities and controls that reflect the cost, risk, and complexity of the decision being considered.

6.4.1. Investment decision-making

Effectively managing assets over their full lifecycle requires effective investment decision-making. This includes decisions about the services and service levels we wish to provide, how we will manage our assets, network architecture, and performance goals.

Investment drivers

The evolving nature of the electricity industry and associated network services and asset solutions is increasingly important.

Our investment process is driven by our asset management focus areas, including:

- **safety**: minimising risk to the public and those working on the network
- **delivering for customers**: ensuring that we deliver outcomes that reflect the levels of service our customers expect
- **environment**: protecting our environment from harm caused by our assets
- **network performance**: ensuring our network continues to perform and deliver appropriate levels of reliability to our customers
- **cost efficiency**: managing our assets efficiently to ensure we deliver cost-effective service to our customers
- **future readiness**: ensuring our network can meet the changing needs of our customers and that we prudently adopt new technology to improve our services.

Later chapters set out how the above areas influence our investment plans during the AMP period.

In summary, we use the following priorities to guide our investment decision-making:

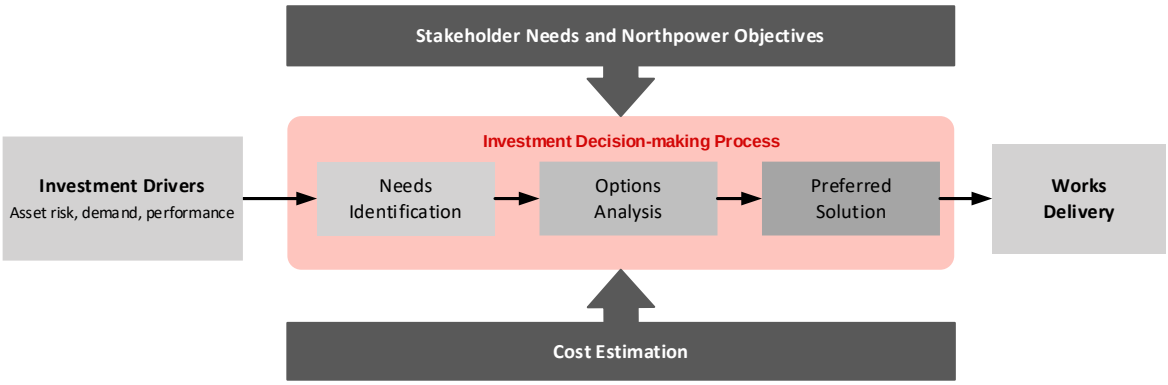
- our primary focus is on investing to reduce the level of risk on the network
- ensure we do not accumulate replacement backlogs, leading to poor performance as a result of underinvestment
- ensure that our network is prepared for growth and the changing needs of our customers
- support our investment planning through targeted improvements to our asset management capability.

To support this, we will pursue improvements in our delivery capability and supporting processes to drive further efficiencies.

Investment decision-making

We have developed a structured decision-making approach for network investments, as illustrated below. Chapters 8 and 9 provide more detail on how this generalised process is applied to our network development and lifecycle investments, respectively.

Figure 6.1: Asset investment decision-making framework



The main steps in the investment decision-making process illustrated above are:

- **Needs identification**: this involves assessing safety risks, capacity constraints, security, reliability, asset condition, type issues, spares availability, and a range of network and site-specific feedback. Identified needs are further assessed based on a range of inputs, including fleet strategies, risk assessments (including criticality attributes), and subject matter expert judgement.
- **Options analysis**: in this step, potential options are developed for each identified need. These options are defined and costed to varying degrees based on the complexity, scale of the identified need, and the costs of feasible solutions. The potential solution is evaluated against approval criteria and reviewed.
- **Preferred solution**: in this step, solutions that have been developed in previous stages or previous planning rounds are prioritised based on the risks associated with the identified need, deliverability, and trade-offs with other investment needs. A preferred solution is identified that may include bundling of multiple needs into one packaged solution.
- **Works delivery**: the chosen solutions will be entered into a draft work programme, which sets out planned works. The deliverability of the overall set of solutions is then evaluated in more detail. Projects in the early years of the plan will be subject to review for full investment approval in accordance with our delegated authority policy.

Investment governance

We have developed a network investment governance framework to ensure that investments go through a rigorous challenge and approval process corresponding to the size and complexity of the investment. We have four work types which are summarised as follows:

- **Complex work**: following needs identification and a high-level options analysis, these projects require a conceptual investigation before proceeding towards delivery. These projects are typically high value and have three approval stages: investigation project, project design and procurement, and project delivery approval.
- **Non-complex work**: these projects can typically be scoped at a reasonable level of detail following needs identification and options analysis, without an investigation, and then moved towards delivery. These projects have one stage of approval for delivery of the entire project.
- **Volumetric work**: are defined as large volumes of equivalent works to be delivered. Volumetric programmes are approved during budget approval for the year and as the replacements are identified, individual replacement work orders are approved by the appropriate delegated financial authorities holder, including the Board.
- **Reactive Capex**: these are projects that arise due to equipment failure during the year. They are typically approved by the delivery governance group, making wider budget adjustments as necessary.

We develop business cases for projects to ensure that the need for investment is well understood, we have considered all credible options, and investments are appropriately challenged. Business cases are reviewed and approved in accordance with our delegated financial authorities, with our large investments being considered and approved by our board.

We have formed two governance groups that oversee network investment:

- **Investment governance group**: made up of the chief executive, chief financial officer, chief operating officer – network, and senior leaders of the network team, the investment governance group is responsible for overseeing all network investment. Where issues are required to be escalated to the investment governance group, they are either resolved at this level or escalated to the Board as appropriate.
- **Delivery governance group**: made up of the chief operating officer – network and senior leaders in the network team, the delivery governance group is responsible for overseeing the delivery of all network investment and ensuring that investment processes are followed, risks are managed, and changes are appropriately controlled. The delivery governance group escalates as appropriate to the investment governance committee.

Our governance processes need to manage the degree of uncertainty inherent in the development of large work programmes. These uncertainties are exacerbated when the scoping and pricing of the project involves long lead times, as is generally the case in the electricity industry. Our development plans are also influenced by third-party requests and timelines for new connections. Over a 10-year AMP period there needs to be flexibility; for

example, using scenarios to support planning decisions. In future AMPs we will provide further detail on these scenarios.

6.4.2. Cost estimation

Good practice cost estimation utilises a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level depending on the nature of the work. The development of estimates can be complex, leading to a degree of uncertainty and estimation risk, in particular for longer-term forecasts.

Investments are estimated using our cost estimation process which differs depending on the type of project.

- **Volumetric projects**: for large volume, low-cost replacement programmes, a volumetric unit rate is used to estimate the programme costs. The unit rate is derived using historical outturn costs.
- **Customised estimates**: for low volume and one-off projects, an estimate is derived using a desktop study of the project to determine a breakdown of the scope, to which unit rates are applied based on historical outturn costs. As the project moves into delivery, the scope and cost estimate become more accurate through further engineering investigation and detailed design.

6.5. Asset management capability

Our people play a central role in our asset management approach, and they need to have appropriate capabilities to manage long-life electricity assets, safely and effectively.

This means our people need to have the right capabilities (including in emerging areas such as asset analytics), and our organisation needs to help them to learn and adapt as the electricity sector evolves.

The increasing use of small-scale distributed generation, the uptake of new energy technologies, and the increasing importance of analytics will have far-reaching implications for the way we operate. The mix of required capabilities will change in the future, and it is important that we identify and implement these so we can continue to deliver an efficient service to our customer owners.

Asset management capability includes processes, systems, tools, and knowledge that we employ to deliver our asset management activities. Some examples of relevant asset management capabilities include:

- development of appropriate objectives and performance monitoring
- data analytics and network modelling, including asset health and criticality analysis
- innovation and prudent adoption of new solutions
- developing planning guidelines and technical standards
- setting out effective maintenance and renewal strategies and plans
- retaining and developing specialist knowledge (e.g., for SCADA, protection).

Effective capability needs to be supported by staff engagement, leadership, and collaboration between different teams and functions. To support these aspects, we are

increasing our focus on developing a formal asset management competency to develop shared understandings around required capability.

6.5.1. Assessing our asset management maturity

This section covers the outcome of our 2023 asset management maturity assessment and how this compares with the assessment we undertook in 2021.

AMMAT

We have used the asset management maturity assessment tool (AMMAT)[21] to undertake a self-assessment of our asset management maturity. As part of the Commerce Commission's information disclosure requirements, we need to include this assessment as part of our AMP.

AMMAT includes 31 questions in six subject areas. It provides a clear and consistent approach to assessing the maturity of an EDB's asset management, including an overview of documentation, controls, and review processes. Each of the 31 topics is allocated a maturity score based on those in the following table.

Table 6.2: Title

MATURITY SCORE		DESCRIPTION
0	Innocence	The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function
1	Aware	The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them
2	Developing	The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation
3	Competent	All elements of the function are in place and are being applied and integrated. Only minor inconsistencies may exist
4	Excellent	All processes and approaches go beyond the requirements of PAS55. The boundaries of asset management development are pushing to develop new concepts and ideas

[21] Our assessment was completed using the Commerce Commission's AMMAT, which is a subset of PAS 55, the precursor of ISO 55001.

2023 AMMAT assessment

For our 2023 assessment, our asset management team undertook a comprehensive review of current capability to reassess our asset management maturity. This included use of the EEA guide with guidance from independent specialists, while leveraging experience and insights from new staff. Based on this review, we updated and revised our AMMAT score.

Box 6.1: 2023 AMMAT score

Our 2023 AMMAT assessment has an overall score of 2.0, which is lower than our assessment of 2.8 in our 2021 AMP.

This scoring reflects a more robust, systematic assessment of our full asset management system. This forward-looking review assessed current capability against best practice asset management and the capabilities required to support:

- our future readiness strategy (see Section 4.4.7)
- our ability to leverage new technology and solutions
- increased network resilience to meet the challenges of climate change
- improved analytics to support increasing renewal needs.

While the review indicated that we have a good understanding of core asset management principles, it concluded that we need to further embed these in our processes and day-to-day work practices. These core principles should then be improved upon as part of a continuous improvement programme.

As discussed in Section 5.7, we plan to seek independent certification of our asset management system in 2023. We are targeting an AMMAT score of 3 in 2025.

Comparison with our 2021 assessment

We have been forthright in our 2023 AMMAT assessment, recognising our strengths as well as the opportunities for improvement. Recognising that the asset management discipline continues to evolve, our assessment has been fully updated since 2021 to reflect capability levels needed to manage our network effectively, now and in the future.

Figure 6.2 below provides a comparison between our 2023 and 2021 assessments. It is set out in terms of the six subject areas covered by the AMMAT.

Figure 6.2: Asset management self-assessment results

The following list describes the key changes in scoring since the last full AMP.

- **Asset strategy and delivery**: we continue to refine our asset management approaches and embed these into our business. Since our previous AMP we have identified a number of areas that can be improved and have scored ourselves appropriately. The event management process should be improved to ensure learnings are captured and appropriately embedded in our business.
- **Communication and participation**: while we have some channels in place to communicate our asset management information, we recognise the need to have a systematic and formal communications plan to ensure our stakeholders receive the most relevant information in a timely manner.
- **Competency and training**: a more formal asset management competency framework should be developed with more structured asset management training, to ensure staff have appropriate capabilities. With the recent uplift in forecast renewal requirements, we have identified the need to have more robust resource planning in place to ensure that our plans are deliverable.
- **Documentation, controls, and review**: we recognised the need to have more robust asset management documentation and performance measures to ensure that our processes are being delivered consistently and our network continues to perform. We have identified a need to integrate continuous improvement and audit processes into our business to ensure our asset management system is working as intended.
- **Structure, capability, and authority**: as our network team has grown, we have recognised the need to have roles and responsibilities defined with more clarity and with better defined progression pathways. To support our future readiness strategy, we need to embed innovation and technology trialling into our business processes.
- **Systems, integration, and information management**: as our asset management has matured, we have recognised the need to improve our data capture, quality, and relevance. We have also recognised that our current asset management information systems will not meet our future requirements.

The revised scoring highlights the areas where improvement in our asset management system is required. We have used this review of our asset management maturity as an important input to the development of our continuous improvement plan (outlined in the next section).

6.5.2. Continuous improvement

We take pride in delivering a safe, reliable, and cost-effective electricity service to our customer owners. To maintain this, given the opportunities and challenges we face in the coming years, we need to continually improve our capabilities. This will be especially important as we ramp up expenditure to ensure the ongoing reliable and safe operation of the electricity network and ensure our network is future-ready to support our customers' energy choices.

- While our current approach represents typical, and in some areas, leading practice among New Zealand EDBs, we recognise that the very best operators in other jurisdictions (Australia, the UK, and elsewhere) are moving to deploy more advanced asset management techniques.
- We face challenges in relation to stabilising asset health, ensuring future resilience, and continuing to maintain a safe and reliable service for customers. We need to ensure our investments that address these issues are efficient and prudent. This requires effective analysis and modelling, underpinned by sound engineering.
- Energy markets are changing and evolving. We are seeing total energy use per household change, and increasing use of new technologies, which may have material impacts on total energy volumes. This situation requires a more refined approach to load forecasting and network planning.
- Both operational and information technology continue to evolve quickly, and we now have access to data and systems which offer the potential to support more granular and incisive asset management decision-making.

Recognising the need for improvement in our asset management approach and the challenges we and the wider electricity distribution industry face, we have developed a continuous improvement programme.

Continuous improvement initiatives

Building on our assessment, we have begun a process to improve our asset management processes and capabilities. The table below summarises the main initiatives that we have begun or plan to start in the coming financial year.

Table 6.3: Asset management improvement initiatives

FUNCTION/AREA	INITIATIVE
Asset management framework and strategies	We have set up a document hierarchy to support our asset management framework and strategies. We will continue to build out this important material to ensure our asset management approach is applied consistently across the business.
Communications plan	Development of a communication and engagement plan to communicate appropriate asset management information and to promote increased awareness within the wider organisation of the asset management system as a whole, and how it informs asset management decisions.

FUNCTION/AREA	INITIATIVE
Competency framework	Development of a competency framework that outlines the competencies required for asset management related roles. The framework will ensure we have training in place for these competency levels to be reached.
Asset information	Building on our new asset information strategy, we will review our asset information standards to ensure that we are capturing the data we require to effectively implement our asset management strategies.
Asset management information system	Our current asset management information system (AMIS) has limitations and will not fully support our future requirements. We have a programme underway to undertake requirements analysis which will inform system selection as part of a future AMIS implementation.
Asset risk modelling	We have developed a suite of asset health and forecasting models for a large number of our fleets, including trialling a new asset modelling software. Based on the outcomes of the trial, we will roll this out across more fleets. We are also in the process of developing our asset criticality framework to better understand the consequences of failure of our assets. Effective asset health (probability of failure) and criticality modelling will improve our understanding of asset risk and support more risk-driven investment decisions.
Event management process	Reviewing and improving our event management process to ensure all events are appropriately escalated and resolved and, where required, are investigated. Corrective actions are tracked to ensure learnings are embedded back into the business.
Further assessments	We plan to carry out a more complete review of our asset management system and this will help to inform our asset management maturity initiatives.

The aim of these improvement initiatives is to ensure we continue to provide customers with a safe and reliable electricity service that meets their needs and expectations, while maintaining affordability. These initiatives support improved efficiency and are directed towards aspects of our business where improvement will bring the most benefit. The initiatives are aligned with and support our asset management objectives.

The linkages between these types of initiatives and improvements to service quality or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives on our performance will be gradual, noting that many of them will take a number of years to fully implement.

Chapter content

7 Risk Management

7. RISK MANAGEMENT

7.1. Introduction

Risk management is a critical component of good asset management.[22] The consideration of risk plays a key role in Northpower's asset management decisions – from network planning and renewal decisions, through to operational decisions. The assessment of risk and the effectiveness of options to minimise it is one of the key factors in our investment choices.

Risk management at Northpower is fundamentally about delivering on our commitments (to our customers, communities, and people) and meeting stakeholders' expectations.

We are committed to managing risk proactively and consistently, in order to:

- ensure a safe and secure environment for our people, partners, and consumers
- support our purpose, ambition, objectives, and commitments as expressed in our statement of corporate intent (SCI)
- pursue opportunities in an informed way, aligned with our risk appetite.
- Our approach to risk management is grounded in our belief that:
- every person at Northpower has a responsibility to identify and manage risks
- a healthy and collaborative culture is a vital part of our risk management
- effective risk management relies on sound judgement, supported by clear evidence
- we can always improve.

In this section we explain how diligent risk management strengthens our ability to deliver a service that is safe, secure, and reliable.

7.2. Our risk management context

Our customers and communities depend on our service, so it is essential we identify and manage risks related to the delivery of a reliable, resilient, and safe electricity service. We recognise we need to be able to continue to supply electricity to our community following adverse events, including natural disasters like major storms. As further context, our region is subject to the risk of tsunami and extreme weather events, including tropical cyclones.

Our lifelines responsibilities are set out in Section 60 of the Civil Defence Emergency Management (CDEM) Act. As a lifeline utility, we must be able to function to the fullest possible extent, even though this may be at a reduced level during and after an emergency.

It is critical that we assess potential risks to our business and develop and implement robust strategies to mitigate these risks. Our board and executive leadership team (ELT) are committed to ensuring that our exposure to risk is at an acceptable level and that we comply with all applicable laws and regulations.

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22 Note that we have formal corporate risk management strategies and procedures in place as well. In this AMP the focus is on asset risk management.

Our risk appetite statement articulates the amount and type of risk that we are willing to manage in pursuit of our strategic objectives and delivery of our company purpose. We discuss this further below in Section 7.3.4.

7.3. Risk management framework

Our risk management and compliance policy and framework aligned to ISO 31000:2018. The policy sets out high-level principles, and the framework outlines our approach to managing risk and achieving compliance. A key objective of the framework is ensuring we operate robust, consistent, and coherent risk management and compliance processes.

Consistent with our risk management policy and framework, our approach to risk management is carried out in accordance with, or informed by, relevant standards and legislation. These include the following:

- ISO 31000:2018 Risk Management – Principles and Guidelines.
- AS/NZS 7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety
- EEA Resilience Guide (2022)
- EEA Asset Criticality Guide (2019)
- Health and Safety at Work Act 2015
- Electricity Act 1992 and Regulations
- Resource Management Act 1991
- ISO 45001:2018 Occupational Health and Safety Management Systems
- ISO 14001:2015 Environmental Management Systems

Our risk management framework is reviewed by the Northpower audit and risk committee and approved by the board at least every two years.

7.3.1. Principles and objectives

The objectives of our risk management framework are to ensure that Northpower operates a robust, consistent, and coherent risk management and compliance process. This ensures an appropriate level of risk is maintained.

The framework recognises that the purpose of risk management is the creation and protection of value and ensures that the approach is:

- customised to Northpower's business activities
- integrated into Northpower's activities
- structured and comprehensive
- inclusive, ensuring that there is appropriate and timely involvement of stakeholders
- dynamic, by anticipating, detecting, acknowledging, and responding to change
- utilising the best available information
- taking human and cultural factors into account
- continually improved through learning and experience.

7.3.2. Risk management methodology

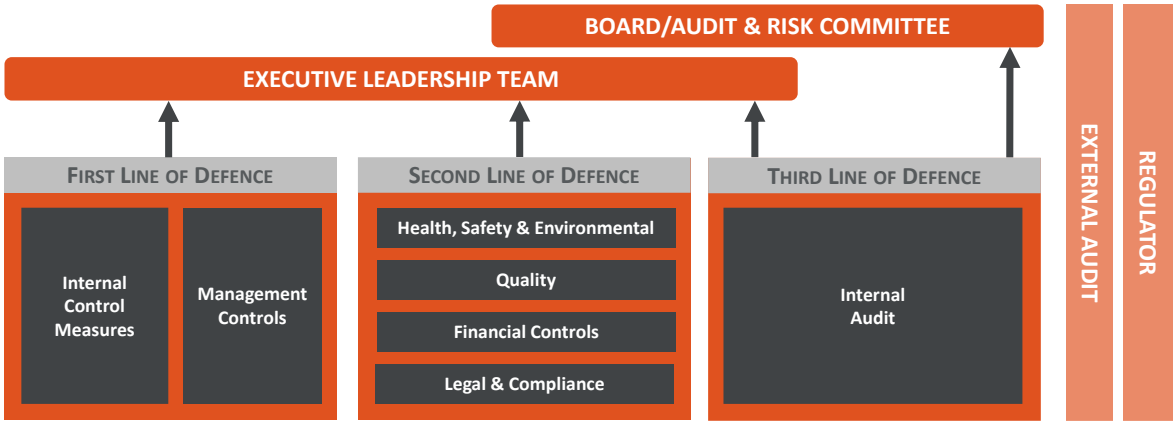
Our risk management methodology combines a top-down strategic assessment of risk against our risk appetite. This takes account of the external business environment. The top-down approach is complemented by the bottom-up operational identification and reporting processes. This includes the review and assessment of business unit risk registers.

Figure 7.1: Risk management approach

7.3.3. Three lines of defence

We adopt a 'three lines of defence' approach to risk management. This approach provides an effective way to enhance communications around risk management and control by clarifying essential roles and duties.

Figure 7.2: Three lines of defence[23]



Under this approach, management control is the first line of defence in risk management. The various risk control and compliance functions are the second line of defence, and independent assurance is the third. The key elements of our approach are shown below.

The first line of defence includes functions that own and manage risk, and is made up of management controls and internal control measures that mitigate risk. Management has ownership of the internal control measures and is responsible for ensuring they are operating at a level that mitigates risk to an acceptable level, in line with the risk appetite

23 Regulator refers to WorkSafe, authorities such as Kaipara and Whangārei district councils, and Northland Regional Council.

set by our board. The main tasks of the first line of defence include to report, escalate, and manage incidents, hazards, and safety concerns.

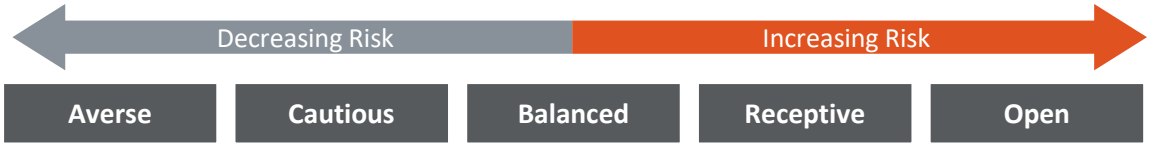
The second line includes functions that oversee risk, including financial control, HSE, quality, legal, and compliance. While management sets the risk management practices, the second line of defence facilitates and oversees the risk practices we undertake. The main tasks of the second line of defence include providing frameworks to manage risk and assisting operational management to develop processes and controls to manage risk.

Internal audit sits as the third line of defence. It is the function that provides independent assurance for the risk management operations implemented by management. Internal audit assesses the design and effectiveness of the first two lines of defence. The first two lines report directly to senior management, while internal audit reports to both senior management and the board of directors.

7.3.4. Risk appetite

Our risk appetite statement (RAS) sets out the amount and type of risk that we are willing to take in pursuit of our ambition and strategic objectives. To aid this process we use the following risk appetite scale.

Figure 7.3: Risk appetite scale



Overall, we have a balanced risk appetite relating to network performance. This is made up of a number of individual settings, including:

- cautious setting for safety
- balanced for network performance
- receptive for portfolio management.

Our risk appetite approach has four key stages:

1. **Agree**: our risk appetite is reviewed and confirmed on at least an annual basis. This normally happens in parallel with the strategy review process. Board workshops discuss and agree on risk appetite for each of our principal risks.
2. **Articulate**: following board agreement, statements on risk appetites are developed for each principal risk. Appropriate metrics with defined limits are then agreed upon to measure whether we are operating within risk appetite. Targeted management action is required if Northpower is operating outside of the defined limits.
3. **Cascade**: following approval by the board, a risk appetite statement is made available to staff. Our staff must ensure that consideration of risk appetite is embedded in day-to-day decision-making (e.g. business cases).
4. **Monitor**, report, and correct: the approved metrics and any associated action plans are reported to the board.

We aim to manage our electricity network in a way that ensures it achieves stable performance at a reasonable cost. We have no appetite for assets failing in a way that results in safety being compromised, prolonged outages, or an inability to remain operational as a business. We accept that outages will occur from time to time, but we ensure that we can mobilise quickly to minimise outage duration and safety impacts.

7.3.5. Risk assessment

Our risk assessment methodology adopts the following approach:

1. **Identify risks**: processes and stakeholders identify new, emerging, and changing risks. Specific details relating to how the risk materialises are captured, along with causes and consequences.
2. **Rate inherent risk**: the consequence and likelihood of each risk is assessed on an inherent basis (i.e. before consideration of the current control environment) using predefined parameters, and the rating is determined using our risk matrix.
3. **Document and assess controls**: key controls in place to mitigate the risks are identified, documented, and assessed to determine an overall control effectiveness rating.
4. **Rate residual risk**: the consequence and likelihood of each risk is then assessed on a residual basis (i.e. after consideration of controls) using predefined parameters, and the rating is determined using our risk matrix (see below).
5. **Agree issues and actions**: based on the residual risk assessment, we form a view on the response required. The escalation and treatment protocol for each risk is determined based on the residual risk assessment.

Figure 7.4: risk assessment methodology

7.3.6. Risk matrix

Network risk assessment and reduction, where economically feasible, forms an important part of overall asset management for electricity distribution networks. A wide range of events with differing probabilities and consequences are usually evaluated, with the results tabulated in a risk matrix format so the risk profile of a particular network can be evaluated.

Northpower's legal, audit, and risk framework sets out the approach that Northpower adopts to manage risk and achieve compliance. This framework includes a requirement to, on at least an annual basis, conduct a risk workshop to assess key network risks, determine any action that is required, and capture these in our risk register.

Figure 7.5: Risk matrix

Likelihood					
Almost certain (multiple times a year)	Low	Medium	High	Very High	Very High
Likely (once a year)	Low	Low	Medium	High	Very High
Possible (at least once every 1 to 3 years)	Very Low	Low	Medium	High	Very High
Unlikely (at least once every 3 to 10 years)	Very Low	Low	Low	Medium	High
Rare (less than once every 10 years)	Very Low	Very Low	Low	Medium	High
	Low	Minor	Moderate	Major	Critical
	Consequence				

Table 7.1: Risk escalation and treatments

Risk Rating	Risk escalation and treatment
Very High	▪ Immediate escalation for board attention. ▪ Detailed plans to mitigate the risk required.
High	▪ Board advised. Immediate escalation for chief executive and ELT attention. ▪ Detailed plans to mitigate the risk required.
Medium	▪ Escalation to management required. ▪ Mitigate or senior management approval to maintain the risk required.
Low	▪ No further escalation required. ▪ Consider use of cost-effective measures to further mitigate the risk.
Very low	▪ No further escalation or treatment required.

7.3.7. Risk records

A risk record is maintained for each risk that is applicable to our electricity network business. This includes:

- risk description
- causes and consequences of the risk
- description and assessment of the external environment relating to the risk
- inherent risk rating
- key controls in place to mitigate the risk and an assessment of control effectiveness
- residual risk rating
- key issues that need to be addressed.

7.3.8. Risk review

Risk workshops are held at least annually with senior management in our network business to assess the key risks, using the approach outlined above, to support achievement of our strategy and business objectives. Priority is given to progressing action plans that will mitigate the highest residual risks. Risks are reviewed at least quarterly to track progress of agreed management action plans. We then rerate risks where appropriate to reflect control improvements or the identification of any new issues.

The results of the annual risk workshop and quarterly risk reviews are reported to our board.

7.4. Managing our key risks

Our risk management activities includes controlling safety risks, avoiding capacity constraints, managing failure likelihood through maintenance and renewals, and ensuring resilience to help mitigate the consequences of major events.

Consideration of risk plays a key role in our asset management decisions, from network planning and asset replacement decisions, through to operational decisions. Our asset management systems and our core planning processes are designed to manage existing risks, and to ensure that emerging risks are identified, evaluated, and managed appropriately.

There are many types of risks associated with electricity networks, some of which include:

- **Safety risk**: electricity network assets and some asset management activities may pose hazards to our staff and the general public.
- **Asset risk**: the possibility of damage to equipment, structures, and assets from third parties, bad weather, and natural events such as earthquakes and floods.
- **Operational risk**: risk of equipment failure or human error that can result in outages.
- **Cybersecurity risk**: as more and more systems in the electricity network become connected and automated, the risk of cyberattacks increases. This could lead to the disruption of supply and damage to equipment.

It is important for us to manage these risks effectively in order to ensure the reliable and secure operation of our electricity network.

The following sections set out the main types of risk that will be most relevant to the electricity business over the AMP planning period and discusses how we aim to manage them.

7.4.1. Safety

Safety is our foremost organisational value. We take an uncompromising approach to safety and will act when we believe there are safety risks for the public, our staff, and service providers. We need to proactively safeguard those working on our network as well as the wider public. Furthermore, as an employer, we aim for an injury-free workplace and actively promote the well-being of our people.

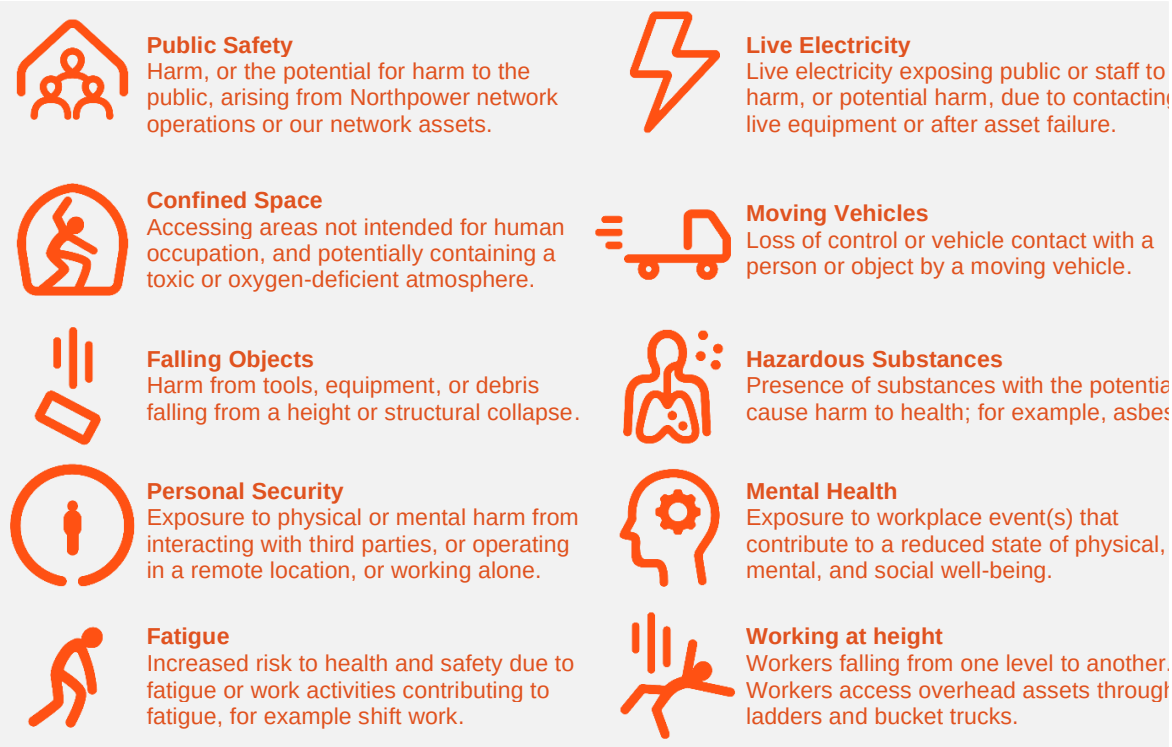
Our health and safety framework enables the consistent and consolidated management of all our risk management obligations.

Source of risk

Our electricity network assets and some asset management activities may pose hazards to our staff and the general public. Some examples include power lines down, low-lying conductors, and pillar fires.

We have identified 10 critical risks associated with the management and operations of our electricity network. These are considered to be risks with the potential for catastrophic consequences.

Figure 7.6: Northpower's critical risks



Activities by the general public can lead to a range of safety risks, including:

- **general public**: contact with our assets (e.g. car versus pole, vandalisation/theft, unauthorised access to our assets/sites)
- **landowners**: vegetation care or management around our assets (e.g. pruning)
- **trades and hauliers**: excavations striking cables, working in close proximity to live assets, oversize loads contacting overhead assets
- **developers and civil contractors**: excavations striking cables, oversize equipment coming into contact with overhead assets.

Approach to safety risk management

We continue to improve existing controls and adopt more effective ones for each of these critical risks. Our live electricity critical risk for those working in the field has been completed and a full suite of critical controls are in place. Public safety, mental health, falling objects, moving vehicles, working at height have had critical controls identified and are moving towards verification and assurance. The remainder of the critical risk programme is due for completion by FY24.

We manage our assets to maintain their condition and performance to mitigate safety risk. Our renewal investments, operations, and maintenance activities help us achieve this.

Figure 7.7: Northpower's health and safety management framework

Effective health and safety performance revolves around people. As depicted in Figure 7.7, our approach to health and safety encompasses the relationships between our people, the work they do, and the environment they do it in, held together with leadership and assurance practices.

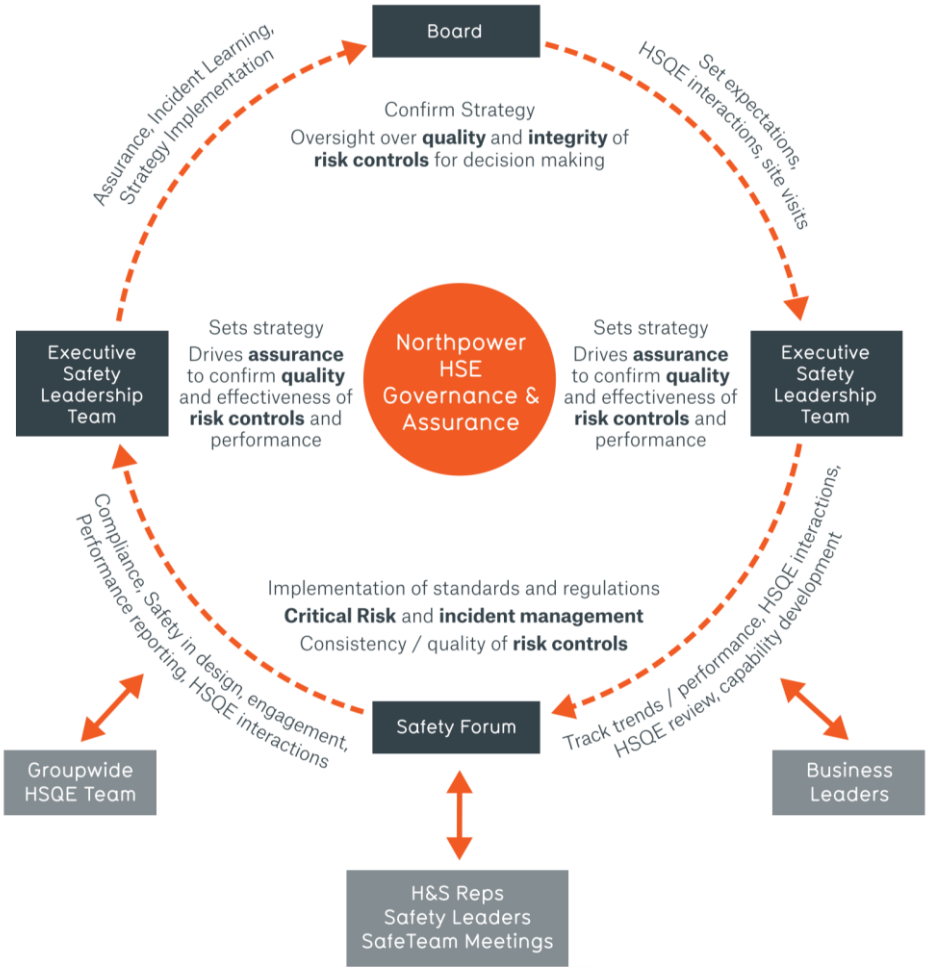
Northpower operates a public safety management system in four domains.

- asset description (including assets, service area, and demarcation)
- risk identification, risk assessment, and treatment of significant risks (including documentation, reviews, and information)
- safety and operating processes (including documentation, responsibilities, legislation, emergency, competencies, change, and incidents)
- performance monitoring (including audits and KPIs).

We have adopted the International Council on Mining and Metals' good practice guide for health and safety critical control management and the implementation guide for critical control management, to support our approach to managing our critical risks. The approach is applied to identify risks in our health and safety risk matrix. We use bow tie methodology to identify the causes and consequences of unwanted material events, which in turn create high and very high (critical) health and safety risks.

Figure 7.8 outlines governance and assurance accountabilities, consultation, and communication flows across Northpower, and two-way engagement with our safety forums.

Figure 7.8: Northpower's health and safety governance and assurance



We use a plan-do-check-act cycle, forming a continuous improvement approach that encourages iterative improvement. This is consistent with the hazard management methodology prescribed in the legislative framework for health and safety.

Table 7.2: Plan-do-check-act cycle

PLAN Identify and assess hazards and safety risks
– **hazard reporting**: through our health and safety reporting system. It is the mechanism to report suggestions for improvement, hazardous conditions or behaviours, and incidents. – **safe work method statements**: conducting job/tasks analysis, emphasising the work health and safety requirements. – **experience**: workers learn on the job and gain experiences with the hazards and risks they have encountered while working. – **hazard profile**: using risk registers to identify and assess health and safety risks. – **industry experience (EEA, ENA, peer utilities)**: our relationships with local industry in the Northland region, with other electricity distributors nationally, and with industry groups.
DO Eliminate and minimise hazards and risks
– **emergency management**: responding to incidents, making sites safe, and recovery. – **incident management**: responding to incidents, investigating them, and drawing learnings from these to share with individuals and teams. – **network operations centre (NOC)**: coordinate workers in the field, providing access permits that isolate workers from electrical hazards and risks. – **security**: electrical assets, such as zone substations and transformers, are locked and secured against unauthorised access. – **work instructions**: detail the methodology required for the task being undertaken to control hazards and risks. – **work type competency**: prescribing competency requirements for workers who access or undertake work on or near the network. This ensures they are competent for the tasks. – **training**: assigning competency requirements to tasks and recording completed training. – **personal protective equipment (PPE)**: is provided to our workers.

CHECK Monitor the effectiveness of control measures

- **asset inspections**: inspection programmes to identify assets that may pose safety risks, e.g. due to increased likelihood of failure.
- **event reviews**: relevant managers meet fortnightly to review high potential events and events of significance. Investigations of these events are reviewed and actions are taken as required to share learnings or improve processes.
- **worksite auditing**: monthly worksite audits to assess hazard and risk awareness and verify that controls are being applied and are effective.
- **safety leadership**: senior leaders conduct visits and discuss with the worksite team members the hazards and risks, and the controls they are using to manage these.
- **safe teams**: monthly team meetings to disseminate health and safety information, and an opportunity for all staff to highlight health and safety issues in their areas.
- **industry learnings**: circulating lessons learned from EEA and other groups on incidents or events that have occurred in their business.
- **external audit**: periodic external auditing of health and safety systems, such as hazard and risk management, including against the requirements of ISO 4801:2001.

ACT Review and improve control measures

- **board review**: the board reviews the operation and management of the network. This includes its health and safety performance, and review of hazards and risks.
- **health and safety steering committee**: responsible for overall management of health and safety, providing oversight and guidance on needed improvements.
- **document reviews**: network standards, work instructions, safe work method statements, and other controlled documents undergo periodic review. Updated documents and communications are circulated to stakeholders.
- **management review**: executive management team review effectiveness of controls in light of risk appetite statement.

7.4.2. Network asset performance

We aim to manage our network in a way that delivers stable performance at a reasonable cost. We have no appetite for asset failures that compromise safety or cause prolonged outages. Outages will occur from time to time, and it is important that we can remobilise quickly and ensure that outages do not overly impact our performance.

Source of risk

Managing asset performance is a key part of effective risk management. Addressing asset risk is a focus of our asset management decision-making, from network planning and asset renewal decisions, through to operations and maintenance. The assessment of risk and the effectiveness of options to minimise risk are key drivers of our investment choices.

Electricity networks have several potential risk sources. These are inherent in the assets used and the functions they perform. The key sources of risk on our network are:

- **Asset failure**: equipment can fail due to a variety of reasons, including poor condition, lack of maintenance, and manufacturing defects.
- **Ageing assets**: over time, our network assets deteriorate and become more prone to failure, requiring repair or renewal.
- **Obsolescence**: assets can become obsolete or inoperable, leading to reduced performance or increased risk of failure.
- **Third-party interference**: accidental or deliberate damage to assets by third parties, such as contractors or the public.
- **Increasing demand**: as our communities grow and customers use more electricity (e.g. for EVs), demand will increase. Network upgrades help ensure we can meet increased demand and continue to provide reliable service to customers.
- **Legacy equipment**: these are items of equipment that may be at higher risk of failure due to type issues.
- **Environment**: exposure to environmental factors such as heat, moisture, and UV radiation can increase the risk of asset failure.
- **Human error**: during installation, maintenance, or operation of equipment can increase the risk of asset failure or damage.

We use records of historical incidents and asset failures, inspection data, staff experience, and modelling to identify asset risk on our network. By identifying and mitigating these sources of asset risk, we reduce the likelihood of asset failure, helping to maintain reliability and safety of the network.

Approach to risk management

Our asset management systems and planning processes are designed to manage existing risk and to ensure emerging risks are identified, evaluated, and managed appropriately.

Managing asset risk involves implementing strategies to identify, assess, and mitigate the risks associated with the assets used in the network. We achieve this through a number of steps including the following.

- **Risk identification**: involves monitoring and inspecting assets including their performance, condition, and criticality
- **Risk assessment**: involves assessing the risk associated with each asset, taking into account factors such as age, condition (health), performance, and potential consequences (criticality)
- **Risk mitigation**: measures to mitigate the risks associated with each asset, such as maintenance, upgrades, and renewal of ageing assets
- **Monitoring and review**: monitoring the condition and performance of assets through inspections, and refining our planned interventions to ensure they remain effective over the planning period

- **Operational readiness**: developing and testing response plans, including plans for responding to severe weather, equipment failures, and other incidents to ensure a rapid and effective response in the event of an outage.

We identify practical interventions that can be applied to mitigate the risks, according to their likelihood and consequence, to ensure the residual risk is at an acceptable level. These mitigation measures are a key input into developing our intervention strategies for network upgrades, maintenance, and renewals.

- **Network upgrades**: this includes increasing capacity of our assets and network to ensure that they can meet this increased demand and provide reliable service to customers. Our approach is set out in Chapter 8.
- **Asset maintenance**: including inspections and repairs are designed to identify and manage existing or potential risks associated with our assets. The goal of our asset condition monitoring approach is to ensure that assets are replaced before their condition and probability of failure starts to deteriorate. Our approach is set out in Chapter 9.
- **Asset renewal**: assets are generally planned for replacement when the asset's health deteriorates beyond acceptable limits. Our visual inspection and test regimes ensure that the condition of our assets is monitored and that they are maintained or replaced prior to failure. Our approach is set out in Chapter 9.

Box 7.1: Asset risk modelling

We identify the need for asset renewal using a combination of asset health and asset criticality. Initial identification of assets is based on asset health modelling, while our criticality framework will be used to prioritise renewals during the planning period.

We are continually developing our health modelling and probability of failure modelling to gain a better understanding of our assets and to support better investment decision-making. We are currently developing a consistent approach to asset criticality modelling to enable better risk-based prioritisation, and to ensure we keep the overall fleet risk at a manageable level as our asset fleets age.

These intervention result in a range of investments and activities which make up our AMP Capex and Opex forecasts.

7.4.3. Digital asset performance

Information technology is key in ensuring our network operates safely and reliably. Our digital asset performance risk relates to poor reliability or performance of critical information technology systems and processes. This includes including protection of our systems against cyber security threats. Digital asset performance risk management provides confidence that our systems are secure, with the right level of controls. Overall, we need to ensure the availability and resilience of system capabilities that enable our electricity operations.

Source of risk

Potential consequences of this risk include network disruption, reputational damage, regulatory scrutiny, litigation, and financial loss. We have identified the following as the key potential sources of this risk:

- under-investment in lifecycle renewals
- poor system configuration and change management practices
- insufficient maintenance of information technology
- environmental factors (heat, dust, etc) that impact the performance of equipment
- insufficient capacity planning
- inadequate redundancy
- cybersecurity attacks.

Of the above digital asset risks, cybersecurity is becoming increasingly important. We need to maintain leading edge cyber resiliency that can both combat the rise in cyber-attacks and protect internal systems to maintain capability and services.

Approach to risk management

We manage risk to our digital asset performance by maintaining a risk register which is continuously assessed, categorised, grouped, and prioritised. The risk register feeds into the work and business planning process. A key aspect is ensuring that there is appropriate governance over information technology projects and change management activities. Some examples of digital asset controls are:

- high availability architecture for critical information technology services
- information technology disaster recovery plan
- device hardening controls (including patch management, application whitelisting, network segmentation, and encryption)
- appropriate system access control (including ensuring users have strong passwords)
- conducting regular security monitoring and penetration testing
- ensuring users receive appropriate cybersecurity awareness training
- ensuring that there is appropriate investment in information technology as part of the annual business planning process. This includes carrying out routine preventative maintenance.

7.4.4. Sustainability and environment

Managing environmental risk is a crucial aspect of ensuring the safe and sustainable operation of our electricity network. To manage these risks, we use a proactive and systematic approach to risk assessment and management.

Source of risk

Long-term sustainability and environmental performance of our business will depend on our ability to understand and mitigate, as far as practicable, the risks our assets and activities pose to the wider environment. These risks include:

- **Sulphur hexafluoride leaks**: SF_6 is widely used as an insulating gas in electrical equipment but is also a potent greenhouse gas that has a high climate change potential. Accidental releases of SF_6 can occur during maintenance, servicing, and other activities, and can contribute to the overall levels of this gas in the atmosphere.
- **Oil leaks**: from transformers can have significant environmental impacts. Transformers contain large amounts of oil. Leaks can potentially contaminate soil and groundwater. Leaking oil can also pose a fire risk.
- **Recycling**: we recycle equipment and other materials, where practical, to minimise the environmental impact of waste disposal and to conserve resources.
- **Waste disposal**: if not managed correctly, waste disposal can pose environmental risks. Redundant assets can contain waste such as metals, printed circuit boards, insulating liquids, and other materials with hazardous substances that may harm the environment if not disposed of properly.

Given the increasing impact of climate-change, we cover this separately in Section 7.4.5.

Approach to risk management

Our environmental management system supports increased environmental capability and management of environmental risk, ensuring regulatory compliance. We are certified to the international standard ISO14001:2015 Environmental Management Systems (EMS). This certification is evidence that we operate to a compliant environmental management plan with clearly articulated processes.

Environmental risk management is undertaken through application of a plan, do, check, act process, with an emphasis on continuous improvement.

Figure 7.9: Electricity network environmental management framework

Improvements to our environmental management processes include monitoring and reporting of a suite of environmental metrics (see Chapter 4). Robust assurance processes provide evidence of our environmental performance and support policies and initiatives including:

- **Sulphur hexafluoride leaks**: minimise future use of SF_6 and implement measures to reduce the risk of accidental releases by ensuring equipment is properly maintained and disposed of.
- **Oil leaks**: regularly inspect and maintain oil-filled transformers in tandem with effective spill response and clean-up plans to minimise the impacts of oil leaks if they occur.
- **Waste management**: properly identify, label, and dispose of hazardous waste in accordance with relevant regulations.
- **Other initiatives**: include waste reduction programmes and recycling.

Stepped-up employee engagement and the establishment of a cross-business environmental action team is leading our future environmental initiatives. These will tackle emissions reduction opportunities where operationally and commercially viable.

By effectively managing environmental risks, we ensure the continued safe and sustainable operation of our network and minimise the impacts on customers and the environment.

7.4.5. Climate change

Climate change has the potential to affect the way customers use electricity and adversely impact the performance of electrical networks. As a result, climate change poses a number of material risks to our network and its performance.

With a measure of climatic change already locked in, adaptation becomes as important as mitigation. We recognise we have a critical role to play in both for Northland. This is reflected in the evolution of our asset management approach to develop a more resilient network.

Sources of risk

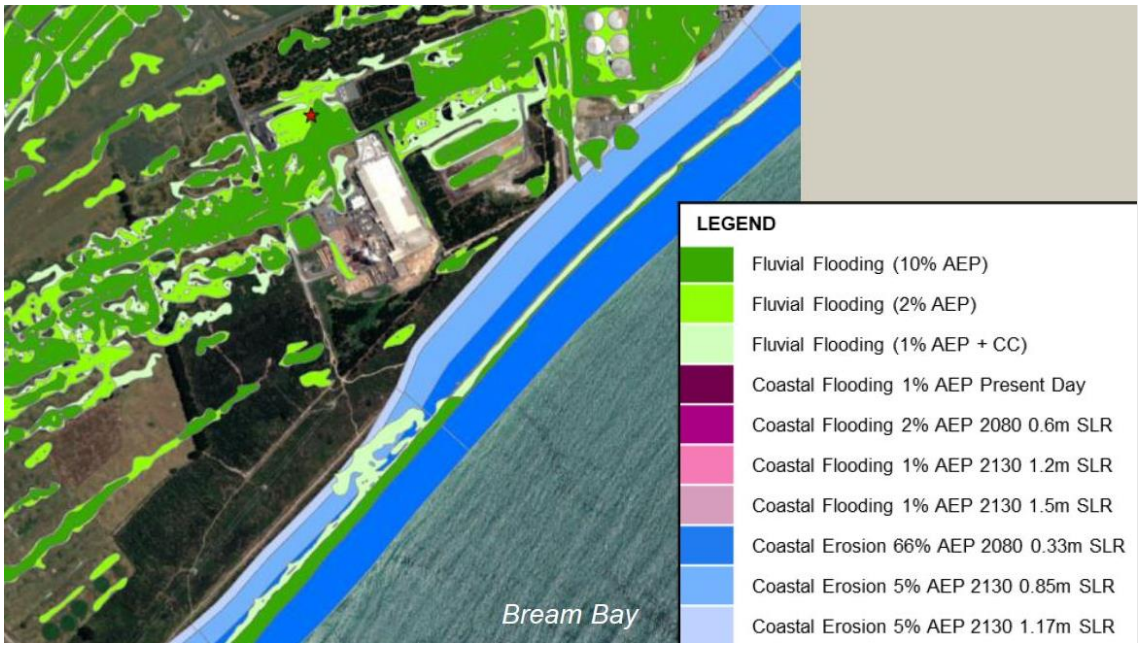
We recognise that to ensure a reliable network we need to be ready to adapt and respond to climate change impacts, particularly where there is proven risk of the potential for more extreme events. We are aware of the potential impacts that climate change may have on our electricity network.

- **Severe weather**: more frequent/severe windstorms with increased likelihood of lightning. Longer outages and more damage to exposed infrastructure from more extreme events (floods, droughts, high winds).
- **Increasing temperatures**: leading to reduced current-carrying capacity of lines and transformers, and increased losses in lines due to operating at elevated temperature. Likely to increase network demand due to increased use of cooling.
- **Sea level rise**: leading to increased flooding risk and storm surges, particularly during high tides. Increased likelihood of flooding/damage to coastal/low-lying infrastructure.

- **Bushfire risk**: potential for more fire starts with more fuel (due to drier vegetation).
- **Increasing rainfall and ground instability**: increasing likelihood of flooding impacting infrastructure at ground level or in low-lying areas. Damage to facilities and infrastructure related to soil erosion and slips.
- **Environmental changes**: higher and more prolonged levels of humidity reducing equipment performance and the need to control faster growing vegetation.

Through our involvement in the Northland Lifelines Group (NLG), we have a broader insight into the impact our service has on other utilities and how climate-change-driven service interruptions could impact other utilities. The group maintains a map of the interdependencies across each sector and has documented infrastructure risk profiles for a wide range of hazards. Work undertaken by the NLG considers infrastructure climate change risk across the energy, water, transport, and telco sectors.

Figure 7.10: Example hazards map



We will evaluate potential impacts of credible scenarios, based on what we are seeing regionally and nationally, and formulate actions to address any probable shifts. We will also review our planning approach considering potential credible impacts of climate change in the project development phase, as well as our operations and emergency response.

Climate-change-related initiatives

We have undertaken a high-level review of these risks and continue to review and reset our response plans. In time, more detailed modelling of climate-change-induced impacts through scenario analysis will be used.

The following table lists possible strategies and actions to better understand and address the potential impacts of possible climate scenarios and their impact on our electricity assets.

Table 7.3: Potential climate change mitigations

RISK	POTENTIAL MITIGATIONS
Severe weather	– Implement more rigorous structural standards – Increased vegetation management, including fall zone risks – Transition to more indoor equipment – Investigate options to reduce impact of air borne debris on critical assets (lines and outdoor switchyards) – Review suitability of design standard for assets – Consider greater diversity of supply routes to improve resilience.
Increased air temperatures	– Increase thermal rating and capacity of assets – Use of more heat-resistant materials – Implementation of more effective cooling for transformers – Peak load shedding – Research availability of more appropriate equipment – Consider options to improve future load forecasting
Sea level rise	– Implement flood control around our assets (dams, reservoirs) – Improve coastal defences (seawalls, bulkheads) – Build in and/or relocate to less exposed locations – Raise structure levels – Improve drainage systems – Engage with local district and regional councils to understand their forecasted changes to sea levels, likely areas impacted, time frames and plans for managed retreat – Prepare a draft response plan with phased implementation for consideration
Bushfire	– Revise and improve bushfire mitigation options – Increase undergrounding of equipment – Examine other bushfire mitigation strategies (operations and equipment selection)

RISK	POTENTIAL MITIGATIONS
Increasing rainfall and ground instability	– Improve flood protection for equipment at vulnerable locations (i.e. flood plains) – Position new equipment in flood-free areas – Transition to more indoor equipment with humidity control – Scan network for assets in low-lying areas and rank according to criticality of asset – Consider outdoor to indoor options for key outdoor infrastructure – Conduct geotechnical assessments of critical assets and carry out mitigations to improve ground stability
Environmental changes	– Adjust equipment specifications to improve humidity performance – Transition to more indoor equipment with humidity control – Adjust vegetation management strategy

The New Zealand government has published the first Emissions Reduction Plan which sets out the path to achieve the country's emissions reduction targets, contributing to global efforts to limit temperature rise to 1.5 C above pre-industrial levels. Major actions include electrification of transport systems and industrial processes, and improved management of waste and high global-warming-potential gases like SF_6.

When planning for new substations and lines we use district and regional council information to identify risks from climate change, as well as tsunami inundation zones and other protected sites. Climate change risks are balanced with the obligation to maintain supply to connected customers. Therefore, maintaining and renewing assets in these at-risk zones will continue unless there is a decision made collectively to retreat.

Wind events and increased fire risks can impact the entire network and require a managed approach. From experience, most wind damage comes from vegetation impacting overhead lines. Our approach is to be more proactive and work with landowners to remove fall-zone trees as these do significantly more damage than wind-blown debris. Extreme fire risk is currently managed to some degree by turning off auto reclosers under advice from Fire and Emergency New Zealand.

More generally, Northpower is committed to making a positive contribution to decarbonisation. We are investing in more distribution and transmission assets and systems to support New Zealand's transition to a low-carbon energy future.

7.5. Emergency response and HILP

Emergency response refers to the actions we take in response to an imminent or ongoing crisis or emergency. The goal of emergency response is to prevent harm, restore services, and ensure we can continue to operate effectively. The specific nature of our response will depend on the type and scale of the incident.

7.5.1. Risk management approach

We have four plans in place for emergency response and ensuring operational continuity.

Coordinated incident management plan (CIMP)

This sets out actions in response to incidents that have (or may have) an impact on supply or the normal operation of the electricity network, and which cannot be managed within normal business-as-usual operations. It outlines details about:

- incident response strategy and procedures
- escalation points for the initiation of the incident management team (IMT)
- roles, responsibilities, and competencies of IMT members
- reporting to manage and advise stakeholders on recovery plans and progress.

Network contingency plans

These detail specific actions to be taken when responding to the loss of certain strategic network assets. This includes the switching plans that should be followed, the critical spares that should be deployed, and the key specialist support to be engaged.

As we develop a greater understanding of credible HILP events, we are developing plans to document operational response, assess the feasibility of possible infrastructure resilience, and establish greater access to other strategic spares and specialist resources.

Crisis management plan (CMP)

This documents our response to a major disruptive incident. The CMP details:

- how incidents with potential to become a crisis should be assessed and escalated
- when our crisis management team should be activated
- how a crisis should be managed
- how a crisis should be closed, and the effectiveness of the response evaluated.

Business continuity plan (BCP)

Our BCP documents the key resources, infrastructure, tasks, and responsibilities required to support critical business functions in the event of disruption. The BCP highlights the critical processes within each business unit and the strategies to be adopted if the facilities, people, applications, suppliers, and equipment we depend on are unavailable.

We test aspects of the CMP and BCP annually, ensuring they can be successfully applied to respond to a crisis and recover critical business functions. This includes hard testing of physically relocating critical staff and the recovery of core systems.

7.5.2. High impact low probability (HILP) risk

HILP events are a particular class of event that typically have return periods of 100 to more than 1,000 years. They can occur at any time. While HILP or extreme events occur very infrequently, their consequences can be significant in terms of damage to an electricity distribution or transmission network, so consideration in terms of overall risk analysis and network vulnerability is warranted.

Source of risk

Some typical examples of HILP or extreme events which can adversely impact a network are:

- a major asset failure or multiple asset failures leading to power system stability problems or long-duration loss of supply, and possible widespread blackouts
- a major earthquake event causing asset damage, resulting in extended-duration power supply interruptions, and prolonged repair time frames
- tsunami
- a major extreme weather event such as a cyclone with very high wind speeds
- a volcanic eruption in the North Island, with major ashfall.

To carry out a complete risk reduction assessment for emergency preparedness planning, it is vital that we identify any vulnerability to plausible HILP events, the likely consequences, and potential mitigation options. Economic analysis enables risk reduction options to be compared.

HILP analysis helps organisations increase their understanding of their relative risk exposure to major events and supports good engineering judgement when making decisions about network resiliency improvements.

Approach to risk management

It is not feasible to protect a network from all HILP events. However, there can be cost-effective ways to reduce exposure and enable faster power supply restoration following a major event, allowing us to meet recovery time objectives. The issue is how much investment should be made to achieve a certain level of risk reduction and where to target expenditure to achieve the greatest benefits. We have carried out a high-level assessment of major and catastrophic HILP events, identifying possible mitigation strategies. These strategies include operational actions, improved recovery strategies and resources, and infrastructure investment options.

These events are listed in Appendix D with possible mitigation options and proposed actions to improve our electricity network resilience

Some of the investments required to implement these options have been included in this AMP, such as the Kensington upgrade and upgrades to the 33kV subtransmission network between Kensington and Maungatapere. Over the next few years we expect to review the remaining HILP risks identified, consult with our stakeholders, and assess whether to make further investments to increase our resilience to such HILP events.

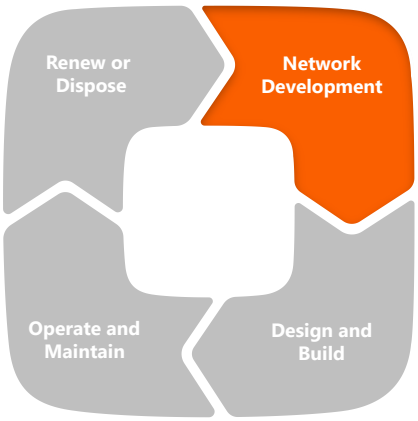
Chapter content

8 Network Development

8. NETWORK DEVELOPMENT

8.1. Introduction

This chapter sets out our approach to developing our network to meet customer demand and connection requirements. It includes our approach to identifying and forecasting constraints, carrying out options analysis, and developing solutions to meet these constraints. This chapter also includes how we invest to improve our reliability, how we consider non-network solutions, and how we are managing the uptake of distributed generation and other new technology on our network. A more detailed overview of our planned network development investments is included in Appendix C.



8.2. Network development overview

As our network grows, we need to ensure that our assets continue to be operated within their designed operating limits. We need to continue to provide appropriate power quality and maintain appropriate levels of security to manage risk and maintain network performance. Network development is the term we use to describe these types of investment. It is typically broken into four key investment drivers:

- **Growth and security**: investments to ensure the demand on the network is met while maintaining security of supply.
- **Reliability and quality of supply**: targeted network investment with the purpose of improving the reliability and quality of supply.
- **Consumer connections**: expenditure to support new connections or increase the capacity of existing connections.
- **Network transformation**: network investment to enable the evolving needs of our customers and manage constraints arising from this changing network behaviour.

The following sections discuss how we plan to meet these investment drivers.

8.3. Network planning process

We follow a defined process to systematically identify and address current and future needs on the network. The diagram below shows a simplified view of our network planning process.

Figure 8.1: Network planning process

The following sections describe each of these steps in more detail.

8.3.1. Forecast demand

Our network development plans are driven by growth in peak demand, not energy consumption. For this reason, we concentrate on forecasting peak demand across all levels of our network. We forecast growth at distribution feeder, zone substation, and subtransmission level. We then aggregate these at grid exit point (GXP) level, and finally a total network demand forecast.

Our load forecasting process looks at a range of data inputs:

- historical load data
- Whangārei and Kaipara district councils' spatial and growth plans
- Statistics New Zealand's dwelling projections
- known step load changes
- DER contribution estimates.

We make some key planning assumptions when using this data:

- Trends for underlying maximum demand are based on historical load overlaid with load growth estimates, based on data from Statistics New Zealand's dwelling projections and district council spatial plans.
- Step load changes are used only from confirmed customer applications.
- We have assumed the uptake of small residential solar panels will have only modest or clustered impacts in the planning period.
- In processing historical data for the load forecast, we remove demand spikes arising from an abnormal configuration where we believe the system may have been configured differently for a shutdown or fault event.

We are continually looking to improve our load forecasting methodology to more accurately reflect emerging technology and potential changes in energy usage.

We explain the inputs and assumptions used in further detail in Section 8.4 below.

Complex load and distributed generation

Upon approval of new load or distributed generation application, the step load changes are updated within the load forecast. We regularly monitor our feeder and substation loads to confirm the actual impact and timing of the new demand connected.

Demand forecasting uncertainty

Due to the nature of demand forecasting there is some uncertainty in our forecasts, and we are reliant on a number of assumptions. The sources of this uncertainty and impacts are outlined below:

- **Rate of growth in the region**: residential and commercial growth is affected by many factors, including economic conditions and demand for housing in the area. We have made estimates based on historic growth as well as council and Statistics New Zealand forecasts; however, these forecasts still have some uncertainty. We have a higher level of confidence for the earlier years of the AMP period, but growth forecasts become more uncertain the further into the future we forecast. The impact of this uncertainty could mean that growth project timings will be updated (either delayed or brought forward), or new projects will be required in future.
- **Step load changes**: we take into account step load changes that are confirmed. Developers also do not tend to forecast their projects as far out as our AMP period and unexpected developments can arise requiring connections to our network. If developer projects change, this can impact the timing of our growth projects as well as create a need for new growth projects.
- **DER uptake**: We have made assumptions around the rate of DER uptake and the impact that this will have on our network. We are still developing our approach to gaining visibility and managing constraints caused by this technology. Therefore, these estimates have some uncertainty. If the actual uptake differs significantly from our estimates, this may drive the need for new growth expenditure or a change to our existing growth plans.

8.3.2. Identify network needs

We systematically analyse the network, using our load forecasts and the network load flow model to determine where and when demand may breach our:

- security of supply standards
- power quality standards
- other planning criteria.

Our key planning criteria are described in the following sections.

Security of supply standard

Security of supply is the ability of a network to meet the demand for electricity where equipment is out for planned or unplanned outages. The more secure an electricity network, the greater its ability to continue to supply electricity during outages.

Electricity supply interruption risks are managed by ensuring adequate capacity in our assets to deliver peak power flows under normal and emergency conditions. This leads to redundancy/duplication of supply, depending on whether the additional costs of an outage to a large customer base outweigh the cost of investment. Security categories are:

- **N security**: a system that is unable to accommodate the full load following the loss of a single power system element

- **N-1 security**: a system that is still able to accommodate the full load following the loss of a single power system element
- **Switched N-1 security**: a system that will have a relatively short outage while alternate supplies are connected (such as switching to a back-up high-voltage feeder) following the loss of a single power system element.

Our network only has full N-1 capacity in certain strategic areas such as subtransmission, high-density urban areas, supplies to critical loads, or where a customer has requested and paid for it.

Our security of supply standard provides a useful benchmark to identify areas on our network that may not currently receive an appropriate level of security. Our security of supply criteria is outlined in the table below.

Table 8.1: Security of supply criteria

ASSET CATEGORY	CAPACITY CRITERIA	RELIABILITY CRITERIA (WORST CASE)	SECURITY OF SUPPLY CRITERIA
400V distribution network	Statutory voltage level	Supply restoration within repair time or within switching time where 400V link pillars present	(N) security of supply for standard residential or commercial connection (N-1) where link pillars are present and backstop capacity available
11kV/400V distribution substation	Transformer continuous rating	Supply restoration within fuse or transformer replacement time or within switching time where 400V link pillars present	(N) security to most urban distribution networks (N-1) where link pillars are present and backstop capacity available
11kV distribution network	Maximum operating load 80% of lowest segment rating	Supply restoration of 80% within switching time	(N-1) security except for spurs
11kV distribution equipment	Regulator rating RMU rating Cable rating	Supply restoration within switching time	(N-1) security except for spurs
33/11kV zone substation	80% of the firm maximum load relative to firm capacity	Load restored 100% within 30 min for >5MVA 80% within 1 hour for <5 MVA	(N-1) >5 MVA (N) <5 MVA
33kV sub-transmission network	110% of overhead line rating 80% of cable thermal rating	Load restored 100% within 30 min for >5MVA 80% within 1 hour for <5 MVA	(N-1) for dual circuits (N) for single circuits
33kV assets within GXP	CB load and fault level rating	Supply restoration within switching time	(N-1) >5 MVA (N) <5 MVA

When there is new demand on our network, we determine what the impact will be. This can involve simple to complex analysis depending on the location, the timing, and the remaining capacity of the feeder and substations. We use SINCAL software to model constraints on our network to understand the impact on the load flow and voltage magnitude on our network.

Forecast demand and capacity is compared with manufacturer nameplate ratings and equipment thermal ratings. This includes assumptions of other factors that may impact our equipment ratings, including ambient temperatures.

We have a process for connecting distributed generation onto our network, which involves analysis of the impact of the new distributed generation or battery storage on our network, as discussed in Section 8.7. Large-scale generation is more complex and more technical requirements are necessary, like network headroom capacity assessment, network study, power quality, fault level, protection systems, initial application, final application, and others.

Power quality standards

An electricity supply should be made available at the stipulated voltage and frequency without distortion of the waveform or loss of symmetry, and with minimum instances or duration of variations beyond the specified limits, or unscheduled interruptions.

The Electricity (Safety) Regulations 2010 sets out requirements for voltage supply installations to customers as:

- 230V ± 6% (i.e. 216.2 to 243.8V) at the point of supply except for momentary fluctuations
- HV ± 6% of the agreed supply voltage, unless otherwise agreed, except for momentary fluctuations
- Maintained within 1.5% of 50Hz (i.e. 49.25 to 50.75Hz) except for momentary fluctuations.

Traditionally ECP36 has been used for standard harmonic level; however, AS/NZS 6100.3.6 is a more recent standard and is regarded as a better and more appropriate standard/code for the distribution industry.

We regularly run load flow calculations to monitor power quality in the network. Using these models we are able to engineer solutions to constraints as they are identified. Typically, the issues that we identify can be solved by re-tapping the distribution transformer or installing a voltage regulator on the associated 11kV feeder.

We take power quality complaints very seriously and will work closely with the customer to identify the issue and find a solution. Our dispatch team sends a staff member out to check on the customer's connection or to identify if there is an issue upstream of their connection point. For example, quality complaints are usually due to distribution transformer tap setting being incorrect, customer's motor start-up not operating correctly, or voltage rise due to solar penetration. The majority of these events can be resolved quickly by adjusting the distribution transformer tap setting. Our staff member on site will advise the customer, or our customer team will get in touch to discuss the source of the issue and the plan for rectification.

We have installed LV monitors in strategic locations on the network to monitor the load and voltage quality in some areas. As part of our LV visibility plan, we will roll out more monitoring to improve power quality across the entire network.

We also plan to use data analytics on smart meter data to help forecast and identify power quality constraints on the LV network. Currently, we have limited access to smart meter data but will continue to work towards accessing more data.

Other planning criteria

We design our distribution system to enable supply to be maintained during planned and unplanned outages where it is economic to do so. We also investigate opportunities to improve the performance of our network by using new technologies or modifying the architecture of the network. To help control feeder performance we set limits for the number of customers connected to each feeder. We also have a HV automation strategy that replaces existing switches or installs additional remote-controlled switches on our network. The priority is the worst-performing feeders, followed by the greatest customer benefit and parts of the network where fault response needs improvement.

Electrical assets such as lines and substations have very long useful lives, and often take many years to plan, consent, and construct. It can be more economic to build an asset with surplus capacity than to complete several small upgrades over its life. Taking this into consideration, when we replace existing electrical assets or other drivers, we consider possible future demand growth and build in additional capacity where economic.

8.3.3. Options analysis

All new network investment needs are carefully examined, ensuring we adopt the most economical long-term solution that also delivers the identified need.

Several options are developed, and the most appropriate option is selected based on several criteria, including the output of an economic analysis. Non-network solutions are also considered where feasible and are employed where they are economic compared to traditional solutions.

We use a range of investment assessment techniques such as net-present value(NPV) analysis and risk assessment to determine which option will give the lowest lifecycle cost and deliver the desired outcome.

The degree to which decision tools are applied depends on the significance of the investment. For example, recurring decisions made at the operational level of our business typically use a predefined decision tool that considers several parameters and identifies one as being optimal. In contrast, non-recurring decisions made at the executive or governance level may consider wide-ranging and complex data, and may use several decision tools to identify an optimal solution from many possible options.

Our guiding principles ensure the proposed investment addresses the network constraint safely, economically, and in line with our long-term strategy. Accordingly, we evaluate the constraint with the following approach.

Initial long list of options

Following the identification of the network constraint or need, we consider both non-network and traditional network solutions to address the need, as well as the do nothing option.

Traditional solutions include investment in:

- installation of new equipment/assets
- upgrade of existing equipment/assets
- reconfiguration of the network architecture
- installation of remote-controlled equipment
- installation of reactive support
- other applicable solutions.

In addition, there are other solutions that could address constraints or defer investment. Some of these include:

- customer demand management
- distributed generation
- energy storage
- alternative supply options.

These are discussed in the following sections.

Customer demand management and ripple control

Customer demand management can provide an alternative to distribution network development. Customer demand can be influenced to reduce peak demand where there is a benefit to the network, driving a more efficient outcome. The benefits of customer demand management include:

- deferral of capital investments
- increased utilisation of the network
- increased efficiency and improved capacity utilisation, lowering prices for customers.

We recognise that incentives are important for customers to shift their demand through such means as interruptible or off-peak tariffs.

We currently use the following customer demand management strategies:

- ripple control – controlled hot water load
- ripple system – other controlled load.

We have also introduced time-of use-pricing, which has a higher variable price for consumption in the peak period. While the differential pricing between peak and off-peak is currently small, this is expected to increase over time, providing an incentive for customers to move consumption to times where there is greater capacity in the network.

For some major projects we would consider paying for customer demand management to avoid or defer network development. These options are considered as part of investment case approvals.

Distributed generation

There are some areas of the network, particularly during holiday times, where mobile standby generators could reinforce the supply. We considered this option as a solution for the rapid load growth in Mangawhai, although we found that this option did not meet long-term needs.

Energy storage

In addition to batteries being used to buffer PVs or for vehicles, batteries also have an application for grid or local electricity network support. Batteries are likely to be an option for grid support when the peak loads are infrequent and/or of short duration, due to the churn losses of the battery. The addition of more batteries with PV installations will help mitigate some of the potential problems that PV saturation would lead to.

The provision of batteries for support during peak load periods may in some cases be more economic than upgrading the network. This is likely to be an option when peak loads are infrequent and/or have a short duration due to battery losses, or if charging can be completed when electricity prices are low and injected when prices are high.

Use applications for grid-sized battery storage include:

- distribution network voltage support for locations with supply constraints
- remote area power supplies that involve PV and/or wind generation for storage of excess energy produced, and for stabilisation of the micro grid
- peak lopping for sites that have an established level of security and supply.

We have no firm plans to adopt large-scale battery technology, but we will consider these as options to help manage infrequent and seasonal peak load spikes on our distribution network.

Alternative supply options

We also consider alternative supply options for areas where it could be more economic to disconnect from the network, rather than upgrading the network. To date we have not yet identified any areas where this would be considered suitable. Most remote loads are farms and lodges and if these sites have unsustainable maintenance requirements, we will consider alternative supplies in collaboration with the customers. There are no current proposals to provide alternative supplies at this time.

List of credible options

All options are narrowed down to a list of credible options that considers the following criteria:

- ensure safety for public and staff
- effectively meet the identified need and service requirements
- cost-effective
- in line with good industry practice
- fit with other planned works
- minimise environmental impact.

Once credible options are identified these are taken through to a more thorough analysis stage.

Economic analysis

A comparison of shortlisted options is carried out by considering the whole-of-life costs for each option. A standard economic evaluation template has been developed to maintain a consistent approach to the analysis. It considers three main aspects for each option:

1. the expected capital investment
2. annual probabilistic reliability risk costs
3. significant changes in ongoing operational expenditure.

The output of this template compares the whole-of-life costs of each option and helps to determine a preferred solution.

8.3.4. Project definition

Choosing a preferred option is based on making a balanced consideration of both the whole-of-life cost and intangible benefits of each option. The preferred option is selected based on the economic analysis output with engineering judgement applied.

Once the preferred option is defined, our projects go through a rigorous challenge and approval process as outlined in Chapter 6.

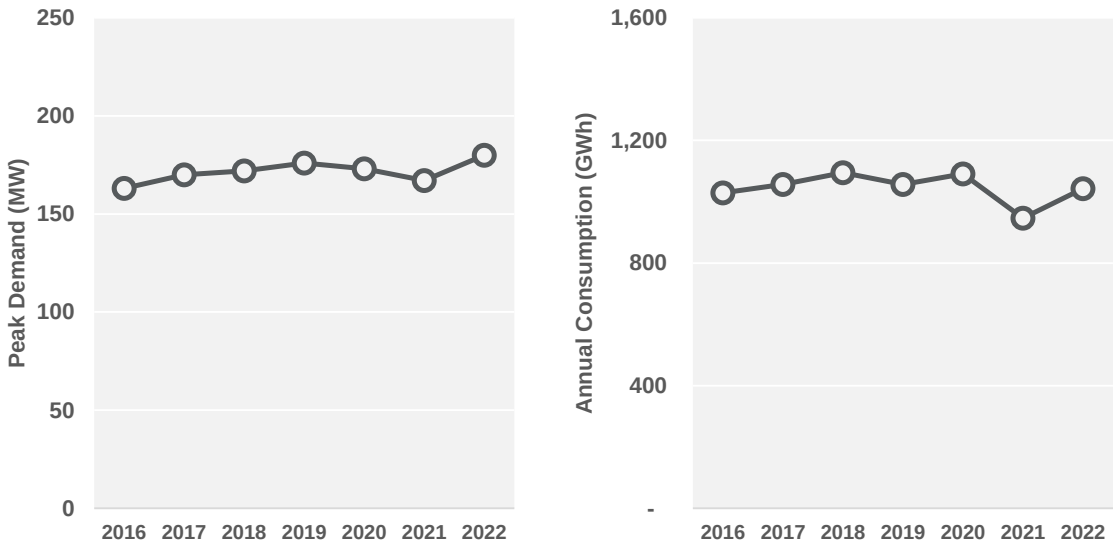
8.4. Network demand

Parts of our network continue to experience significant demand growth. This section gives an overview of historical and projected demand on our network over the next 10-year period.

8.4.1. Historical peak demand and energy consumption

Over the last five years, we have seen an average annual increase of around 1.2% in peak demand. In 2021, we saw a sudden drop in consumption and demand due to the Covid-19 pandemic. This limited the operations of our large industrial customers as well as some commercial establishments.

Figure 8.2: Historical peak demand and energy consumption



This growth reflects reasonably steady growth in domestic connections, static growth in commercial connections, and some new industrial projects. Some upgrade projects were initiated by existing large commercial and industrial customers.

Historical peak demand per GXP

An overview of FY22 load and consumption on our three GXPs is shown in Table 8.2.

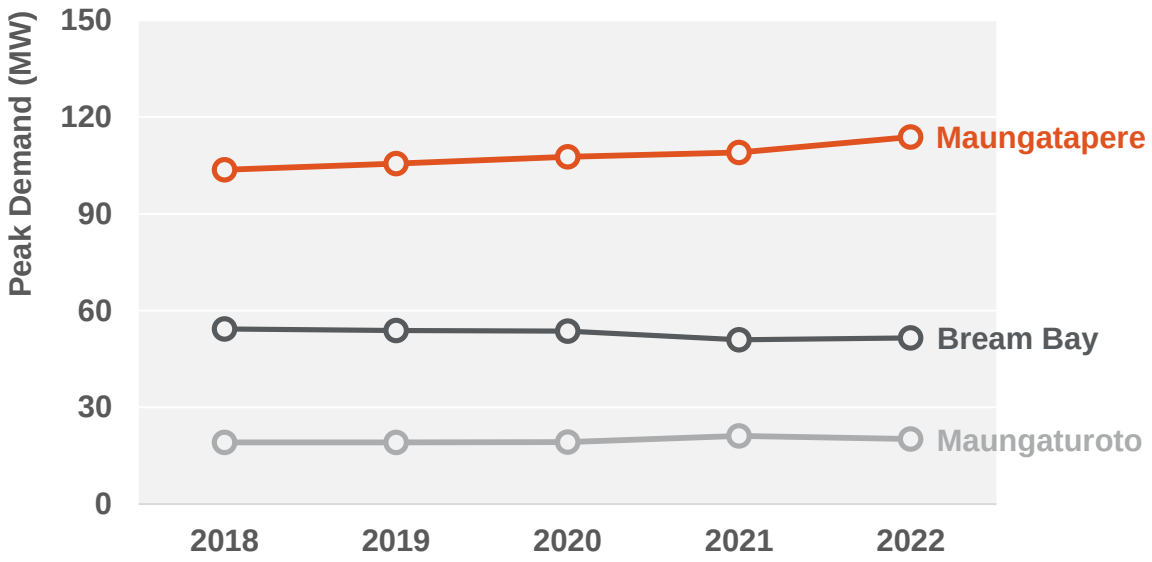
Table 8.2: Overview of the FY22 load and consumption on our three GXPs

GRID EXIT POINT	SUPPLY KV	PEAK DEMAND MW	ANNUAL CONSUMPTION MWH	% OF TOTAL
Bream Bay	33	51	361,526	34.7%
Maungatapere	110	112	578,558	55.5%
Maungaturoto	33	21	102,331	9.8%
Total		180[24]	1,042,415	100%

Figure 8.3 shows the GXP historical peak demand has a consistently increasing trend at the Maungatapere GXP which reflects greater growth in the Whangārei district urban areas, due to large subdivision development. The Bream Bay and Maungaturoto GXPs are relatively constant over the last three years; however, we expect some load increase from the new subdivisions and commercial establishments being developed in the Bream Bay and Mangawhai areas.

[24] Total peak demand reflects the coincident peak between the three GXPs.

Figure 8.3: GXP historical peak demand



In April 2022, we had a decrease of around 30MW peak demand in the Bream Bay GXP due to the closure of the New Zealand Refinery. This reduction will be reflected in the FY23 peak demand.

Demand from industrial customers

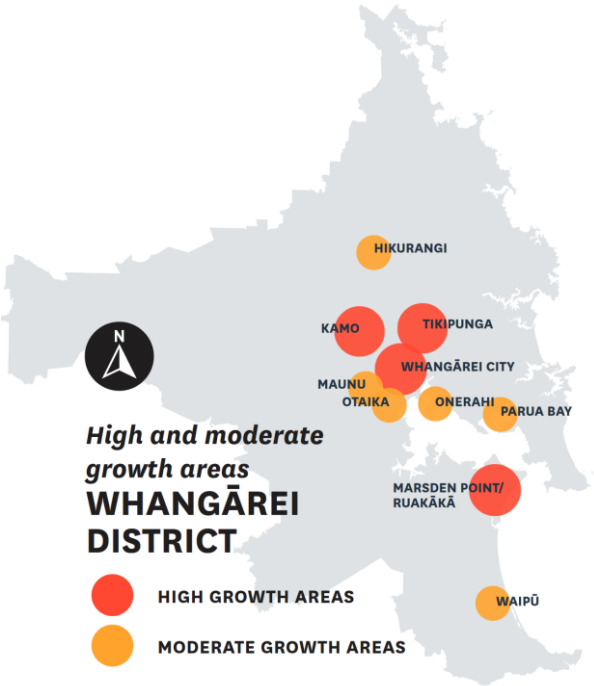
Customers with high demand or annual consumption are defined as very large industrial (VLI) loads. These customers generally have special requirements regarding the security of supply (typically duplicate transformers and lines or cables) as their loads are too large to supply with emergency standby or backup generation. These loads are normally supplied directly from the subtransmission system at 33kV, or by one or more dedicated 11kV distribution feeders from a nearby zone substation.

During FY22, five VLI customers consumed around 44.5% of the electricity supplied by our network. However, this is expected to significantly decrease due to the closure of the refinery.

8.4.2. Load growth considerations

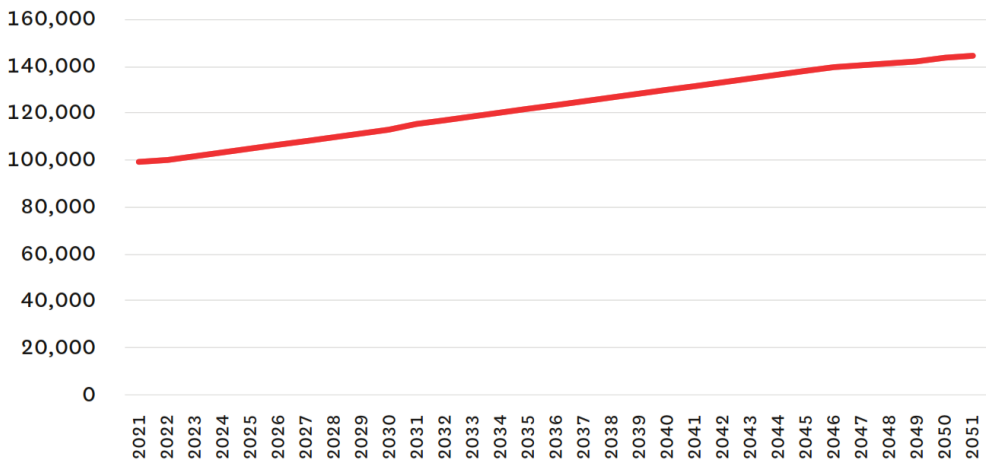
The Whangārei and Kaipara district councils have published their long-term plans and forecasted population increases over the next 30 years. The population increases are driving significant rezoning to support future large-scale residential and commercial growth, particularly in areas close to Auckland. There are also some forecasts that coastal beach towns may turn into ‘zoom towns’, with people moving to more rural areas as remote working becomes more common.

Figure 8.4: Whangārei District Council growth strategy



Population forecasts for the Whangārei district estimate a higher growth trend over the next 30 years compared to the previous census period (2013–2018) where the population grew by 18%, compared to the New Zealand average of 10.8%. Whangārei District Council is forecasting the population to exceed 140,000 by 2050.

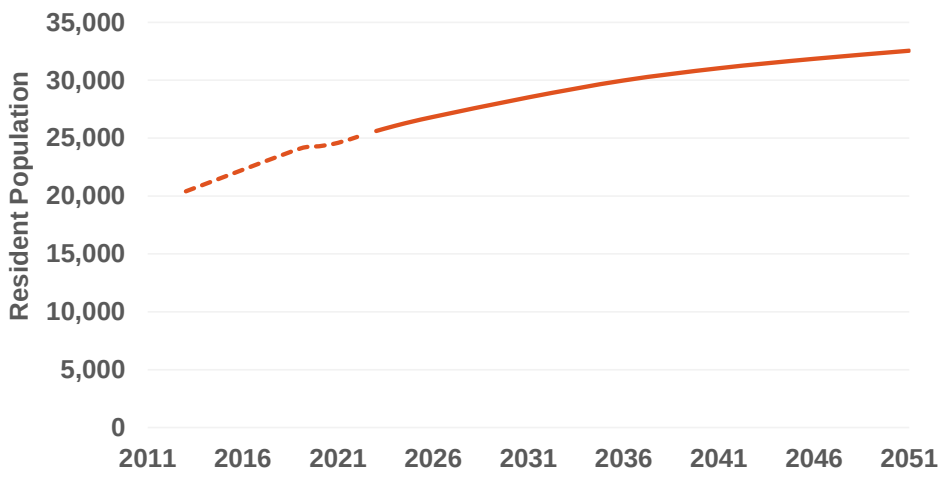
Figure 8.5: Whangārei district population projections[25]



The population for Kaipara is showing some softening compared to the 2013–2018 growth rate, which reached 20% over this period. Population predictions for Kaipara are forecast to reach a total of 32,600 residents by 2051.

[25] Source: Whangārei District growth strategy, Sustainable Futures, 23 Sept 2021.

Figure 8.6: Kaipara district population projections[26]



In their 30+ year population forecasts, Whangārei and Kaipara district councils are projecting significant residential growth in Kamo, Tikipunga, Whangārei, Ruakākā, Bream Bay, Waipu, and Mangawhai. Some coastal towns are also projected to have an increase in population, with growth in remote working.

Table 8.3: Uncertainties related to our growth forecasts

AREA	GROWTH FORECASTS AND UNCERTAINTIES
Bream Bay	The Whangārei District Council has designated large areas of land for development, with the possibility of a deep-water port being established at Marsden Point. We expect large development in this area, including a retirement home, commercial establishments, and others.
Waipu	Waipu is a fast-growing area, and we have noticed a sizeable increase in demand in Waipu. With large areas being designated for development, we suspect the load to increase over the planning period.
Dargaville	The potential for large-scale forestry development with wood processing could lead to significant load growth in the longer term.
Hikurangi	Moderate growth is expected at the substation associated with the development of holiday homes and lifestyle blocks.
Kamo	High growth in the development of residential areas and lifestyle blocks is expected to continue for the next five to 10 years. See Section 8.5.1 for the development projects for this area.
Whangārei City	The urban area is expected to grow out towards the west, meaning substantial residential load growth is expected on the Maungatapere substation in the medium term. A new substation at Maunu was just recently commissioned to support this development in the medium to long term.
Mangawhai	With its proximity to Auckland, the Mangawhai area has seen a steady increase in residential and commercial development as more permanent residents make this area their home and increased amenities and services are established. Network development projects have been included to support the growing demands in this area.

[26] Source: Kaipara infrastructure strategy, Rev 6, Feb 2021.

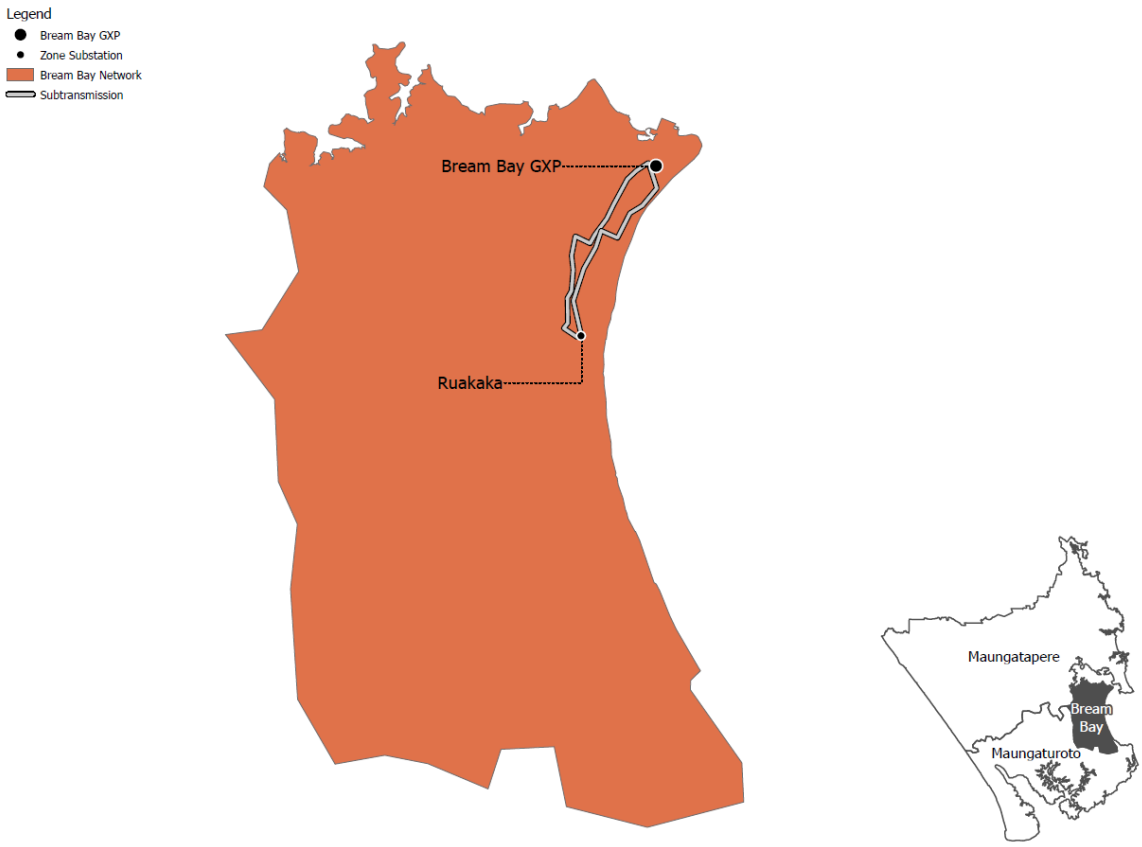
8.4.3. Forecast GXP load growth

This section sets out projected load growth for the three GXPs that supply our network.

Bream Bay GXP

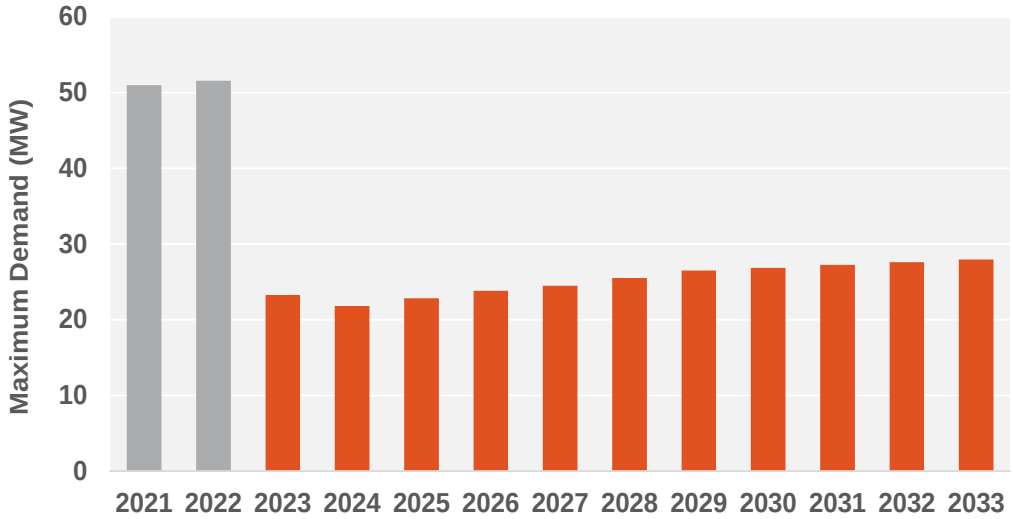
The Bream Bay GXP supplies Ruakākā, Marsden Point, and One Tree Point (adjacent to Bream Bay GXP). This includes large industrial customers such as Harvey LVL Plant.

Figure 8.7: Bream Bay GXP service area



Our demand forecast for Bream Bay GXP is shown in Figure 8.8. The significant drop in demand for the Bream Bay GXP in 2023 is attributed to the closure of the New Zealand Refinery. Aside from this, we are expecting growth during the period from large subdivisions and other commercial and industrial establishments being developed. The Whangārei District Council identified Marsden Point and Ruakākā as high-growth areas and Waipu as a moderate-growth area.

Figure 8.8: Bream Bay GXP forecast maximum demand



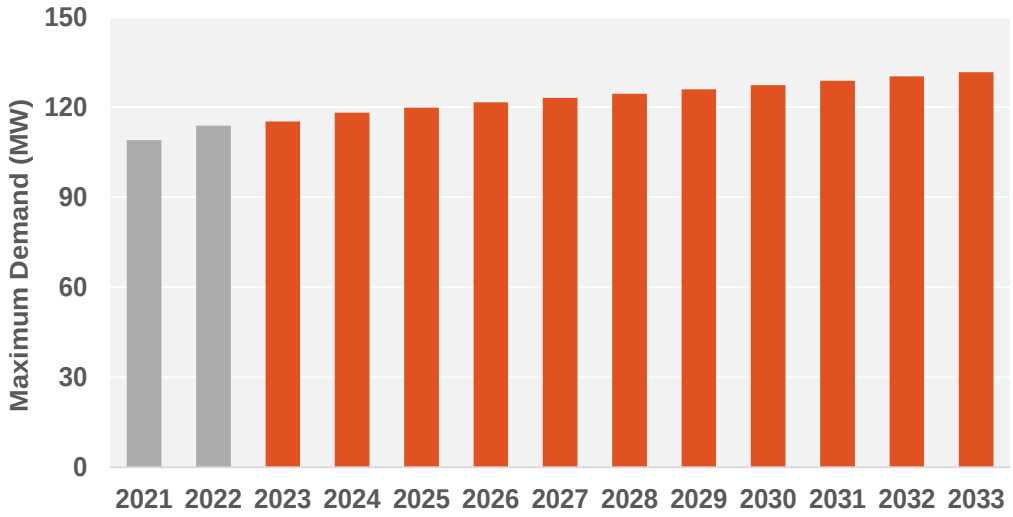
Maungatapere GXP

Maungatapere GXP supplies the Kensington regional substation and the Maungatapere regional substation as shown below. In terms of area, Maungatapere GXP supplies the Dargaville and Whangarei district councils areas except for Ruakākā, Marsden Point, and One Tree Point which are supplied by Bream Bay GXP.

Figure 8.9: Maungatapere GXP service area

Our demand forecast for Maungatapere GXP is shown in Figure x. Historical load growth at the Maungatapere GXP is anticipated to continue. The Whangārei District Council identified Kamo, Tikipunga, and Whangārei City as high-growth areas, while Maunu, Otaika, Onerahi, and Parua Bay are moderate growth areas.

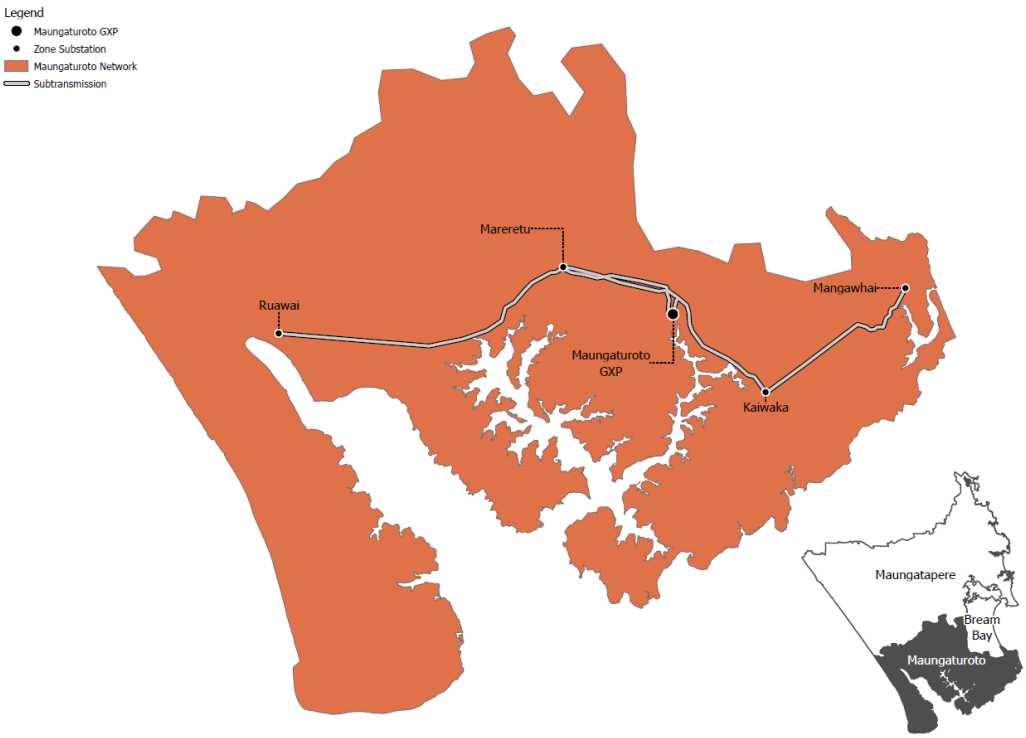
Figure 8.10: Maungatapere GXP forecast maximum demand



Maungaturoto GXP

The Maungaturoto GXP supplies the Kaipara District Council region except for Dargaville (which is directly connected to the Maungatapere GXP), as shown below.

Figure 8.11: Maungaturoto GXP service area

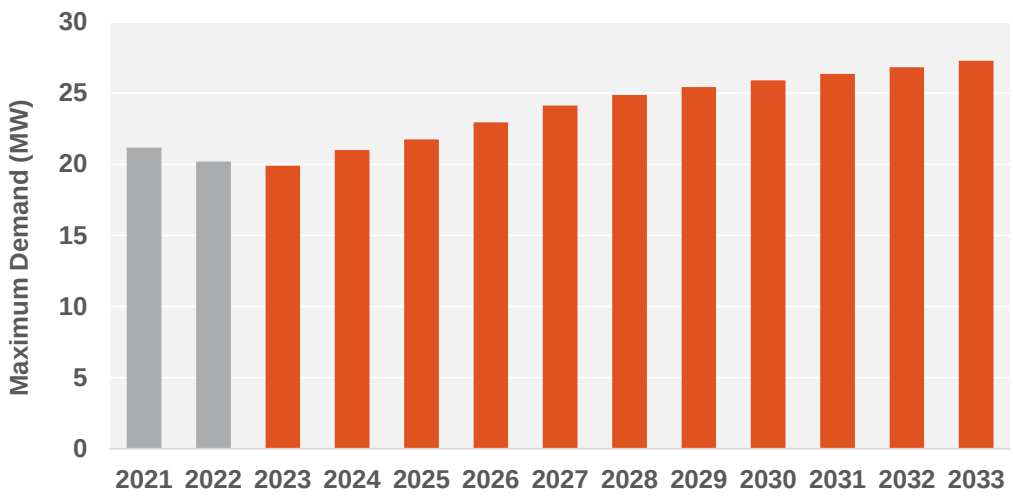


The load on the Mangawhai substation includes primarily coastal residential and holiday homes. Some commercial connections are present and there is some dairy farming in the Tara area. The urban areas include Mangawhai Heads, Mangawhai village, and Lang's Beach.

Our demand forecast for Maungaturoto GXP is shown in Figure 8.12. The substation load is characterised by high peak demands during holiday periods. The load has grown at a higher rate in recent years compared to other parts of the Northpower network and this is expected to continue over the next 10 years. Kaipara District Council has identified Mangawhai as a high-growth area. We have seen an average of 150 additional customers per year connected in this area over the last two years.

We have received several large load applications in the area consisting of commercial, industrial, and residential, with an expected load of around 7MW over the next 10 years.

Figure 8.12: Maungaturoto GXP forecast maximum demand

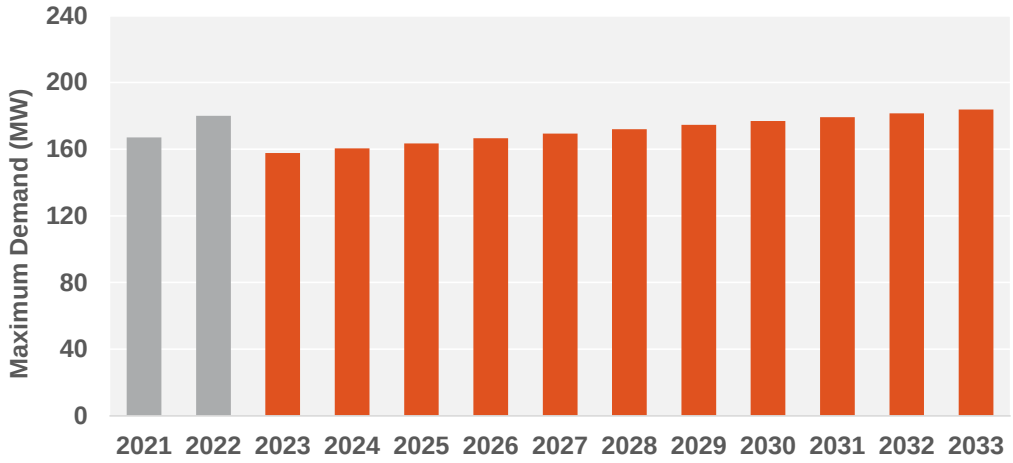


Total GXP load forecast

Our total GXP load forecast (based on coincident peak) is shown in Figure 8.13. The demand growth averaged across the entire network is expected to be approximately 1.5% per annum for the 10-year forecast period. Output from the embedded generators at Wairua and Bream Bay, and domestic solar PV, will offset some of this growth.

The peak load (net of embedded generation) on the network is expected to increase from the present 158MW to around 184MW over the next 10 years.

Figure 8.13: Total GXP forecast maximum demand



8.4.4. Forecast substation and subtransmission load growth

The following table compares the firm capacity of our substations and subtransmission with the present and forecast load. The uptake of solar PV connections is recorded but not incorporated into the forecast because the impact on peak demand (given our winter peak) is negligible. At this stage, we have not incorporated the impact of battery storage into our zone substation forecasts as we do not anticipate the impact of batteries to be significant within the next 10 years.

Subtransmission load forecast

Table 8.4: Subtransmission load forecast

SUBTRANSMISSION CIRCUIT	SECURITY	FIRM CAPACITY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Kensington to Tikipunga A & B	N-1	**20.6**	20.4	20.8	21.2	21.7	22.1	22.5	22.9	23.4	23.8	24.2	24.6
Kensington to Kamo A & B	N-1	**22.9**	24.1	24.3	24.5	24.7	25.0	25.2	25.4	25.6	25.9	26.1	26.3
Kensington to Alexander to Tikipunga	N-1	**21.9**	11.9	12.5	13.2	13.8	14.4	15.1	15.7	16.4	17.0	17.6	18.3
Kamo to Hikurangi	N-1	**14.3**	15.4	15.5	15.6	15.7	15.7	15.8	15.9	15.9	16.0	16.1	16.2
Tikipunga to Onerahi	N	**22.9**	15.8	16.1	16.4	16.7	17.0	17.3	17.6	17.9	18.2	18.5	18.8
Maungatapere Regional to Maungatapere	N-1	**13.7**	8.4	8.6	8.7	8.9	9.0	9.1	9.3	9.4	9.6	9.7	9.9
Maungatapere Regional to Poroti	N	**8.6**	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.8	2.8
Maungatapere Regional to Dargaville	N -1	**20.8**	8.6	8.8	9.0	9.2	9.3	9.4	9.5	9.5	9.6	9.7	9.8
Maungatapere Regional to Whangārei A & B	N-1	**22.9**	24.0	24.4	24.8	25.2	25.4	25.6	25.8	26.0	26.2	26.5	26.7
Bream Bay to Ruakākā A & B	N-1	**13.7**	8.4	8.5	8.6	8.7	8.8	8.9	9.1	9.2	9.3	9.4	9.5
Maungaturoto to Mangawhai	N-1	**13.7**	15.2	16.2	16.8	17.8	18.8	19.3	19.5	19.7	19.9	20.1	20.2
Kaiwaka to Mangawhai	N	**11.3**	8.3	9.3	9.8	10.7	11.7	12.1	12.3	12.4	12.5	12.6	12.7

Legend	
	<= N-1 firm capacity rating
	> N-1 firm capacity rating, <= N-1 firm emergency capacity rating
	> N-1 firm emergency capacity rating

Substation load forecast

Table 8.5: Substation load forecast

SUBTRANSMISSION CIRCUIT	SECURITY	FIRM CAPACITY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MAUNGATAPERE GXP													
Kensington Regional	N-1	**50**	60.8	61.8	62.7	63.6	64.5	65.4	66.3	67.2	68.1	69.0	69.9
Alexander Street	N-1	**15**	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9
Hikurangi	N-1	**10**	6.9	7.0	7.0	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
Kamo	N-1	**15**	12.6	12.7	12.9	13.0	13.2	13.3	13.5	13.7	13.8	14.0	14.2
Ngunguru	N	**5**	2.8	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7
Onerahi	N-1 switched	**15**	7.2	7.3	7.4	7.6	7.7	7.8	8.0	8.1	8.3	8.4	8.5
Parua Bay	N	**5**	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4
Tikipunga	N-1	**20**	17.3	17.5	17.8	18.0	18.3	18.5	18.8	19.1	19.3	19.6	19.8
Maungatapere Regional	N-1	**30**	46.1	46.8	47.4	48.0	48.4	48.9	49.3	49.8	50.2	50.7	51.1
Maungatapere	N-1	**7.5**	5.4	5.5	5.7	5.8	6.0	6.1	6.3	6.5	6.6	6.8	6.9
Maunu	N	**10**	3.5	3.8	4.0	4.3	4.4	4.4	4.5	4.6	4.7	4.8	4.8
Kioreroa	N-1	**20**	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.8	8.8	8.8	8.8
Poroti	N	**5**	3.1	3.1	3.2	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.7
Whangārei South	N-1	**10**	10.6	10.7	10.8	11.0	11.1	11.2	11.3	11.4	11.6	11.7	11.8
Dargaville	N-1	15	11.9	12.1	12.3	12.5	12.6	12.7	12.7	12.8	12.9	13.0	13.1

Legend	
	<= N-1 firm capacity rating
	> N-1 firm capacity rating, <= N-1 firm emergency capacity rating
	> N-1 firm emergency capacity rating

SUBTRANSMISSION CIRCUIT	SECURITY	FIRM CAPACITY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
BREAM BAY GXP													
Bream Bay	N	**10**	5.5	6.0	6.7	7.4	7.8	8.5	9.2	9.4	9.5	9.6	9.7
Ruakākā	N-1	**10**	8.3	8.6	8.9	9.1	9.4	9.7	10.0	10.2	10.5	10.7	10.9
MAUNGATUROTO GXP													
Maungaturoto	N-1	**7.5**	6.6	6.7	6.7	6.7	6.8	6.8	6.9	6.9	6.9	7.0	7.0
Ruawai	N	**5**	3.7	3.7	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.1
Kaiwaka	N	**5**	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.8
Mangawhai	N	**10**	7.5	8.6	9.2	10.3	11.4	12.1	12.5	12.8	13.2	13.5	13.8
Mareretu	N	**5**	2.5	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.9	2.9

Legend	
	<= N-1 firm capacity rating
	> N-1 firm capacity rating, <= N-1 firm emergency capacity rating
	> N-1 firm emergency capacity rating

8.5. Network constraints

This section outlines the constraints identified on the network based on our load forecast, security of supply standards, power quality standards, and other planning criteria.

8.5.1. Growth and security of supply constraints

The following are constraints on the subtransmission network forecast over the next 10 years relating to underground subtransmission cable or overhead line limits.

1. The Mangawhai substation continues to experience significant load growth. We have received several large load applications consisting of commercial, industrial, and residential, with an expected load of around 7MW over the next 10 years. It is expected to breach the substation capacity of 10MVA in FY26. A new Mangawhai central substation is underway and is to be completed in FY26 as discussed in Section 8.6.1.
2. The Kensington regional substation has already reached its N-1 firm capacity limit of 60MVA and is expected to reach 70MVA in the next 10 years. This is one of our critical substations, supplying seven zone substations and a dairy-focussed substation with nearly 30,000 customers. The substation will be upgraded to two 100MVA transformers which are underway and to be completed in FY26 as discussed in Section 8.6.1.
3. The single subtransmission line supplying Kaiwaka and Mangawhai is causing reliability issues and a high demand forecast is expected to breach N security due to significant development in Mangawhai. A new subtransmission line from Maungaturoto to Mangawhai is underway and expected to be completed in FY25 as discussed in Section 8.6.1.
4. Maungatapere regional substation has limited back-feed capacity to supply Kensington regional substation with the demand of >60MVA under a second outage scenario. This requires several network upgrades to resolve. As a longer-term programme we plan to bolster this back-feed capability, starting with restoring one of the disconnected subtransmission lines from Maungatapere to Whangarei in FY25. This is briefly discussed in Section 8.6.
5. The existing two subtransmission lines from Kensington to Tikipunga A and B supplying Tikipunga, Ngunguru, Onerahi, and Parua Bay will breach N-1 security in FY29. These subtransmission lines are planned to be upgraded in FY26 as discussed in Section 8.6.1.
6. Large developments in the Bream Bay area are expected to breach substation N-1 security. We plan to install an additional 15/23MVA substation and upgrade the existing 11kV switchboard in FY26 as discussed in Section 8.6.1.
7. Existing subtransmission line from Maungaturoto GXP to Maungaturoto substation is also expected to breach N-1 security in FY26. There is a planned upgrade of the existing subtransmission line in FY25 as discussed in Section 8.6.1.

8. The two existing subtransmission lines Kensington to Kamo A & B, supplying Kamo, Hikurangi, and Kauri substations, are expected to breach N-1 security by FY29. A planned additional new subtransmission cable will be installed from Kensington to Kamo in FY26 as discussed in Section 8.6.1.
9. Waipu is anticipated to continue to grow, with a large subdivision development under way, and may require a new substation in the next 10 years. A new substation is proposed in FY33 as discussed in Section 8.6.1.
10. Too many customers are being supplied by a distribution feeder in Kamo. This is a high-growth area due to new subdivisions being built. Feeder N and N-1 security are forecast to be exceeded. Feeder upgrade and reconfiguration are proposed in FY24 as discussed in Section 8.6.1.
11. There are limited back-feed capabilities for various distribution feeders currently not meeting security of supply guidelines (Mangawhai, Parua Bay, Waipu, and Ngunguru). A new voltage regulator is to be installed on each feeder to allow for additional back-feed capacity as discussed in Section 8.6.1.
12. There are limited back-feed capabilities for the Dargaville feeder which is currently not meeting security of supply guidelines. Feeder upgrade and reconfiguration are proposed in FY24 as discussed in Section 8.6.1.
13. N -1 security for the subtransmission line supplying Maungatapere to Whangārei South is expected to be breached by FY28. This can be managed through load transfer from Maungatapere to Kensington so no upgrade is planned.

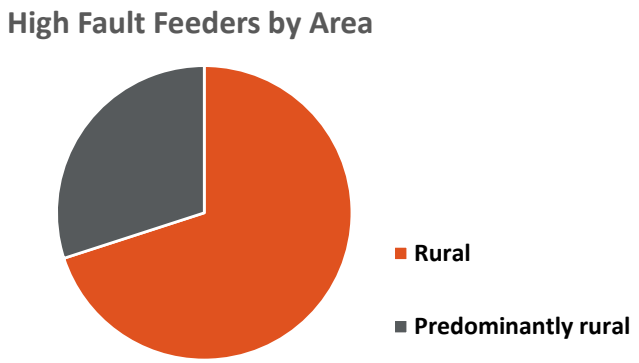
8.5.2. Reliability and power quality needs

The following constraints years relate to reliability and power quality needs.

14. Kensington regional substation, supplying around 30,000 customers, has no 110kV bus, causing reliability and operational issues. A new 110kV bus arrangement is underway and expected to be completed in FY26 as discussed in Section 8.6.2.
15. There is no contingency supply to 624 customers for Moir Point distribution feeder. New feeder interconnection with ring main units are underway and expected to be completed in FY23 as discussed in Section 8.6.2.
16. There is poor visibility of LV distribution network. We will be installing a smart distribution system in strategic sites as discussed in Section 8.6.2.
17. Where there is poor feeder performance, we will be installing or replacing existing switches in strategic sites with remote control capability, as discussed in Section 8.6.2.
18. In some high-density areas there are large pole-mounted distribution transformers installed. We will convert the existing pole-mounted distribution transformers to ground-mounted distribution transformers as discussed in Section 8.6.2.
19. Some overhead lines section in the network need to be converted to underground due to safety issues, such as poles in high traffic and crash areas. We will be converting existing overhead lines in identified areas causing safety issues as discussed in Section 8.6.2.

We monitor the worst-performing feeders in our network. The 10 feeders with the highest number of faults are mostly the longest in our network. They represent 35% of the total network length and 11% of the total customers. They are predominately rural feeders as highlighted below in Figure 8.14. The 11kV feeder with the highest number of faults is our longest radial feeder. It has many spurs and is the source of persistent intermittent trips which can be very difficult to locate.

Figure 8.14: Highest fault feeders by area (rural and urban)



We are looking for opportunities to establish additional 11kV feeder ties to improve restoration options to enable more customers to be restored faster. Some of the related issues we are resolving include:

- poor feeder performance due to a lack of visibility of fault, and long restoration periods causing reliability issues
- too many customers are being supplied by a single distribution feeder in a high-growth area following new subdivisions
- limited back-feed capabilities for various distribution feeders in areas such as Mangawhai, Waipu, Ngunguru, Parua Bay, and Dargaville.

8.6. Network development projects

This section outlines significant network development, reliability, and power quality projects over the 10-year planning period.

8.6.1. Growth projects

Our planned growth projects ensure we maintain capacity and security of supply, and support forecast growth rates. We split the growth projects into two categories:

- major projects: involving substations and subtransmission circuit upgrades
- distribution and LV projects: upgrading distribution feeders and LV networks.

These projects and forecast expenditures are presented in the following figures and tables.

Major growth projects

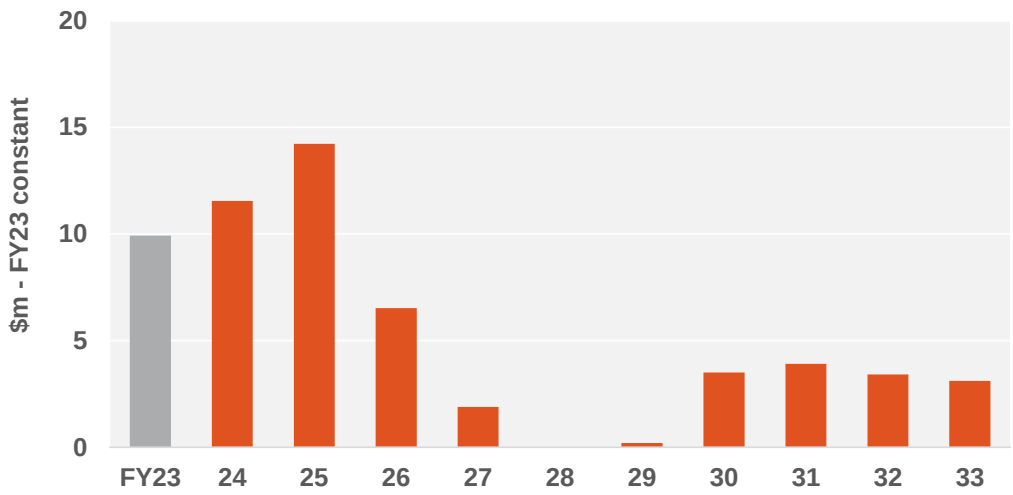
Over the AMP period, we plan to spend $48.3m on major growth projects. The majority of this is in the early part of the period, with the Mangawhai and Kensington upgrades. Our expenditure in major projects drops off in the middle of the period before picking back up in FY29 with the new Waipu zone substation and transmission line.

Table 8.6: Forecast major growth projects

GROWTH - MAJOR PROJECTS	CONSTRAINT	YEAR	BUDGET
Mangawhai central zone substation The project will install a new 15/23 MVA substation to support the emerging load growth. Growth in the Mangawhai area has accelerated since 2020, and now requires an upgrade in network capacity to support further development and security of supply. The design is complete and project is underway.	1	FY23–25	$10.1M
Kensington 110/33kV transformer replacements The project will replace existing two 50MVA power transformers with two 100MVA 3-phase power transformers to maintain N-1 security and meet the forecast demand at the substation. The design is complete and project is underway.	2	FY23–26	$9.7M
Maungaturoto to Mangawhai 33kV line The project will install a new 28km subtransmission cable/line from Maungaturoto substation to Mangawhai substation to improve the reliability and security of supply to Kaiwaka and Mangawhai zone substations. This will also support the growing demand in the Mangawhai area and provide contingency supply under planned outages to perform asset renewal and maintenance. The design is complete and project is underway.	3	FY23–25	$6.7M
Restore existing 33 kV subtransmission line from Maungatapere regional to Whangārei The project will restore the connectivity of the existing 33kV OH subtransmission line between Maungatapere regional substation and Whangārei South substation. The restoration of the disconnected subtransmission line, coupled with some network upgrades, will provide an additional 25MVA capacity to the subtransmission circuits. This will resolve the issue of security of supply for the Kensington regional substation and the group peak demand of Whangārei, Maunu, and Kioreroa substations.	4	FY24–25	$1.6M
Replacement of two Kensington to Tikipunga 33kV subtransmission UG cables The project replaces the existing subtransmission circuits from Kensington to Tikipunga, supplying Tikipunga, Ngunguru, Onerahi, and Parua Bay substations. This will maintain N-1 security and meet the growing demands.	5	FY24–26	$3.8M
Install additional 15/23 MVA power transformer and 11kV switchboard upgrade - Bream Bay The project will install an additional 15/23 MVA transformer to provide N-1 security to Bream Bay zone substation and meet the growing demands. In conjunction, a new 11 kV switchboard will be installed to replace the existing 11 kV switchboard, along with the secondary system.	6	FY24–26	$6M

GROWTH - MAJOR PROJECTS	CONSTRAINT	YEAR	BUDGET
Upgrade 33kV subtransmission line Maungaturoto GXP to Maungaturoto The project will upgrade the existing subtransmission line to meet N-1 security as well as growing demands.	7	FY25	$0.2M
Install new 4km 33kV subtransmission feeder cable from Kensington to Kamo The project will install an additional 33kV subtransmission cable from Kensington to Kamo to maintain N-1 security and meet the growing demands.	8	FY26–27	$3.8M
Install new Waipu substation and 33kV subtransmission line The project will install a new 33kV subtransmission line from Ruakākā to Waipu and a new substation in Waipu. Waipu is anticipated to continue to grow, with large subdivision development planned, and may require a new substation in the next 10 years. Alternative options will be considered as part of the options analysis. We will continue to monitor load growth in this area and consider all feasible options to defer investment.	9	FY31–33	$14M

Figure 8.15: Forecast major growth project expenditure



Distribution and LV projects

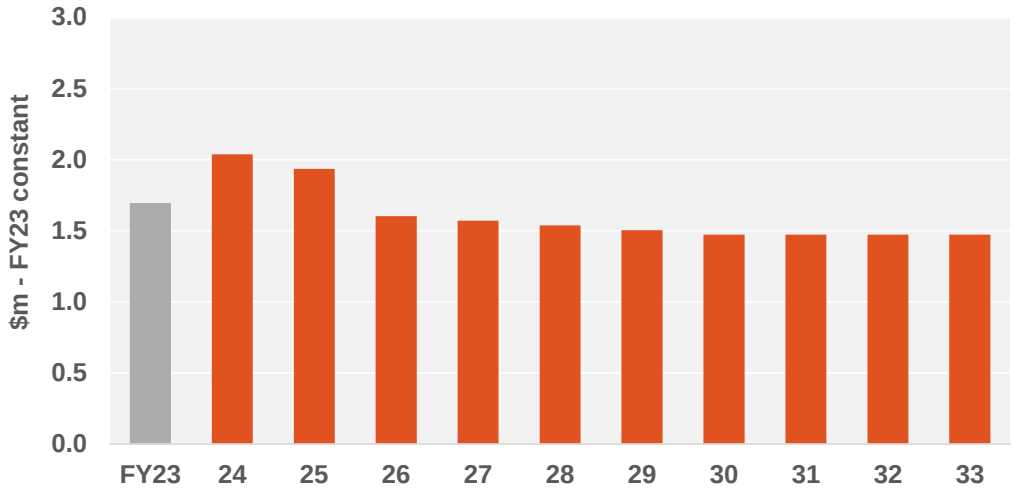
Over the AMP period, we plan to spend $16M on distribution and LV projects. The majority of this is to address specific constraints identified in the short term. Due to the nature of distribution and LV constraints, it is difficult to forecast with certainty beyond three to five

years. The expenditure in the remainder of the period is forecast based on historical expenditure in this area. Specific projects will be identified closer to the time.

Table 8.7: Forecast distribution and LV projects

GROWTH - DISTRIBUTION AND LV REINFORCEMENT PROJECTS	CONSTRAINT	YEAR	BUDGET
Upgrade and reconfiguration of Kamo CB2 The project will upgrade a weak section of the existing OH lines and the reconfiguration of the KMOCB2 feeder to allow for growth and provide N-1 security to the feeder. This reconfiguration involves installing a recloser and change in open points to transfer 273 customers without compromising the reliability of the existing feeders. KMOCB2 is experiencing load growth due to significant residential subdivisions being built in the area.	10	FY24	$0.2M
Ngunguru back-feed constraint mitigation The project will install a new 3MVA voltage regulator and associated equipment to allow for additional back-feed capacity to Ngunguru substation. The Ngunguru substation is N security; therefore, the back feed can only be achieved through two of the existing three Ngunguru feeders.	11	FY25–26	$6M
Waipu feeder capacity constraint mitigation The project will install a new 3MVA voltage regulator and associated equipment and feeder reconfiguration to allow for additional back-feed capacity to the Waipu feeder. The reconfiguration will transfer around 240 customers from RKACB2 (Waipu Feeder) to RKACB7 to provide full back-feed capacity. This will also provide RKACB2 additional back feed to the Mangawhai substation.	11	FY25–26	$6M
Mangawhai back-feed constraint mitigation The project will install a new 3MVA voltage regulator and associated equipment to allow for additional back-feed capacity to the Mangawhai substation. The project will provide additional back-feed capacity until the new Mangawhai substation is completed, and will also be useful as a long-term solution for both feeders and substation. The design is complete and project is underway.	11	FY23–24	$0.5M
Parua Bay back-feed constraint mitigation The project will install a new 3MVA voltage regulator and associated equipment to allow for additional back-feed capacity to the Parua Bay substation. The design is complete and project is underway.	11	FY23–24	$0.5M
Dargaville CB4 security of supply upgrade The project will install an HV switch on DARCB8 feeder and around 700m of new overhead line. This will allow for DARCB4 feeder to be fully offloaded at all times and provide additional switching capacity to DARCB8 feeder. This will remove the security of supply constraint due to limited transfer capacity.	12	FY24	$0.1M

Figure 8.16: Distribution and LV Capex



8.6.2. Reliability and quality of supply projects

Reliability and quality of supply projects help to enhance the reliability and performance of our network by improving outage restoration time and the impact of outages.

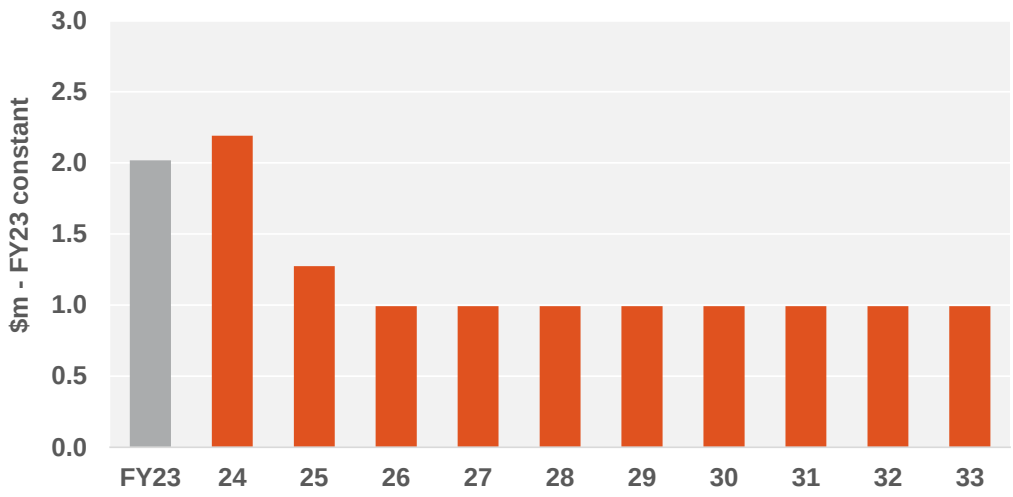
Over the AMP period, we are forecasting to spend $11.4m on reliability and quality of supply projects. In the short term, we have a higher level of expenditure to address the Kensington bus reconfiguration before forecasting a relatively consistent level of expenditure on smaller automation and undergrounding projects.

Table 8.8: Forecast reliability and quality of supply projects

RELIABILITY AND QUALITY OF SUPPLY PROJECTS	CONSTRAINT	YEAR	BUDGET
Kensington 110 kV bus reconfiguration and transformer circuit breakers The project creates a 110kV bus at the Kensington substation with a bus section circuit breaker, enabling both power transformers to be returned to service during a single line outage. The design is complete and project is underway.	14	FY23–26	$2.9M
Install new RMUs and extend the Moir Point distribution feeder The project is to install two new ring main units and around 0.6km 11kV feeder cables. This will provide feeder interconnection to a spur lines that supplies 624 customers. This will also provide contingency supply under unplanned and planned outages to perform asset renewal and maintenance and support the growing demand in the area. The design is complete and project is underway.	15	FY23	$0.2M
SMART distribution system (load monitoring) The project will install new transformer load monitoring devices to monitor voltage quality in the low-voltage network and to document any issue identified. The design is complete and the project is underway.	16	FY23	$0.1M

RELIABILITY AND QUALITY OF SUPPLY PROJECTS	CONSTRAINT	YEAR	BUDGET
11KV Feeder mid and tie-point remote controlled switching The project will improve the feeder performance and provide visibility of the network by installing new switches or replacing existing manual switches in strategic locations with new remote-controlled switches. The design is complete and the project is underway.	17	FY23–24	$0.3M
Ground mounting of two and four pole-mounted distribution transformers The project will convert existing pole-mounted distribution transformers to ground-mounted transformers to address public safety issues. The project is expected to continue over the next 10 years.	18	FY23–33	$4.0M
Overhead-to-underground conversions The project will convert existing overhead lines to underground cables to address public safety issues. We had identified some problem areas such as cars hitting poles three times in the last six years. The project is expected to continue over the next 10 years.	19	FY23–33	$4.9M

Figure 8.17: Forecast reliability and quality of supply expenditure



We expect to see the following benefits from these investments:

- reduced impact of outages through the use of remote-controlled switches equipped with fault indication. Faulted sections can be more easily identified and isolated while the healthy portion of the feeder remains energised
- quicker identification of fault location allows system control to quickly isolate the faulted area, which reduces travel time for line crews
- increased operational flexibility and real-time control of assets
- remote management of feeder and substation load when needed to defer investment
- improved customer satisfaction due to shorter outages.

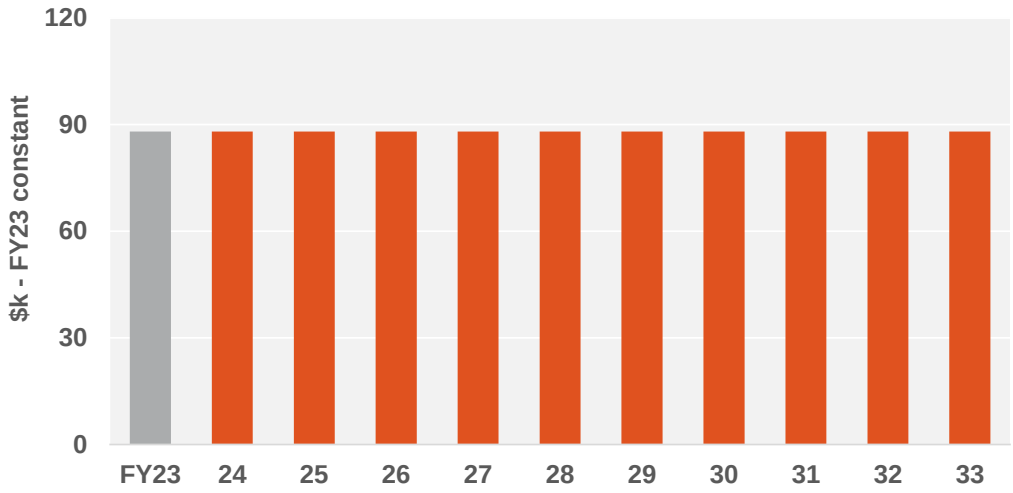
8.6.3. Consumer connection

Consumer connection investment is expenditure to support the connection of new customers to the network. Connection volumes are largely driven by population growth, from small residential connections to large subdivision developments and new commercial and industrial establishments being constructed. In the last four years, we connected an average of around one thousand new customers to our network per year.

In connecting new customers, we use a process that ensures it is fair, cost-effective, and efficient. The goal of our capital contributions policy is to ensure that our existing customers do not cross-subsidise development costs. Therefore, developers pay for the network extension back to the nearest point of supply (that has sufficient capacity). The costs to the network for new development are kept at a minimal level, as reflected in our net consumer connection forecast below.

Over the AMP period, we are forecasting to spend $880k on consumer connection.

Figure 8.18: Forecast consumer connection expenditure (net)



Updated capacity charges

Under our updated policy there will now be standard flat rates for most residential and general connections. It is expected that the simplified flat fee per standard connection will decrease the time to process new connection applications. Larger non-standard connections will be charged a flat rate per kVA of capacity, which equates to the same charge as the standard rates. This approach allows us to invest in bulk capacity upgrades to make the cost of new capacity as low as possible for all customers connecting.

8.7. Distributed generation

8.7.1. Distribution generation policy

Where customers want to connect distributed generation, they are required to pay any costs associated with upgrading the network to accommodate the connection and to deliver the

required export capacity. We do not anticipate that distributed generation will materially impact development plans by requiring network expenditure to be brought forward.

Our connection of distributed generation policy follows the requirements set out in Part 6 of the Electricity Industry Participation Code 2010. Our website includes guidelines on connection requirements, consultation, and approval.

We recognise that distributed generation can provide a range of benefits:

- reduction of peak demand
- helping to manage existing network constraints
- deferring or even avoiding investment in additional network capacity
- contributing to supply security
- making better use of local primary energy resources
- reducing line losses.

Distributed generation can, however, have undesirable impacts that need management:

- increased fault levels, requiring protection and switchgear upgrades
- more complex network management, resulting from multiple points of supply
- uncontrolled voltage rise beyond statutory ceiling limits
- potential to impact power factor at GXPs
- the introduction of harmonic currents
- potential for back feeding into the network with inherent safety implications
- reticulation capacity requires upgrading where generation exceeds existing capacity
- imbalances on the low-voltage network.

We work with those wanting to connect distributed generation to our network to deliver the benefits, while also ensuring that all parties manage and mitigate any adverse impacts.

The key requirements for those wishing to connect distributed generation to the network are covered in the following sections.

Connecting distributed generation

A party connecting distributed generation must comply with our safety requirements, as well as all electrical industry codes and regulations. Our requirements for small-scale generation are based on AS/NZS 4777 Grid Connection of Energy Systems via Inverters. To protect the network and other energy consumers, we may physically disconnect distributed generation that does not comply with these requirements.

Connection terms and conditions are set out in accordance with the Electricity Industry Act 2010. Information on the application procedure for potential connection of distributed generation (including relevant forms and required standards) is available on our website.

Distributed generation and development planning

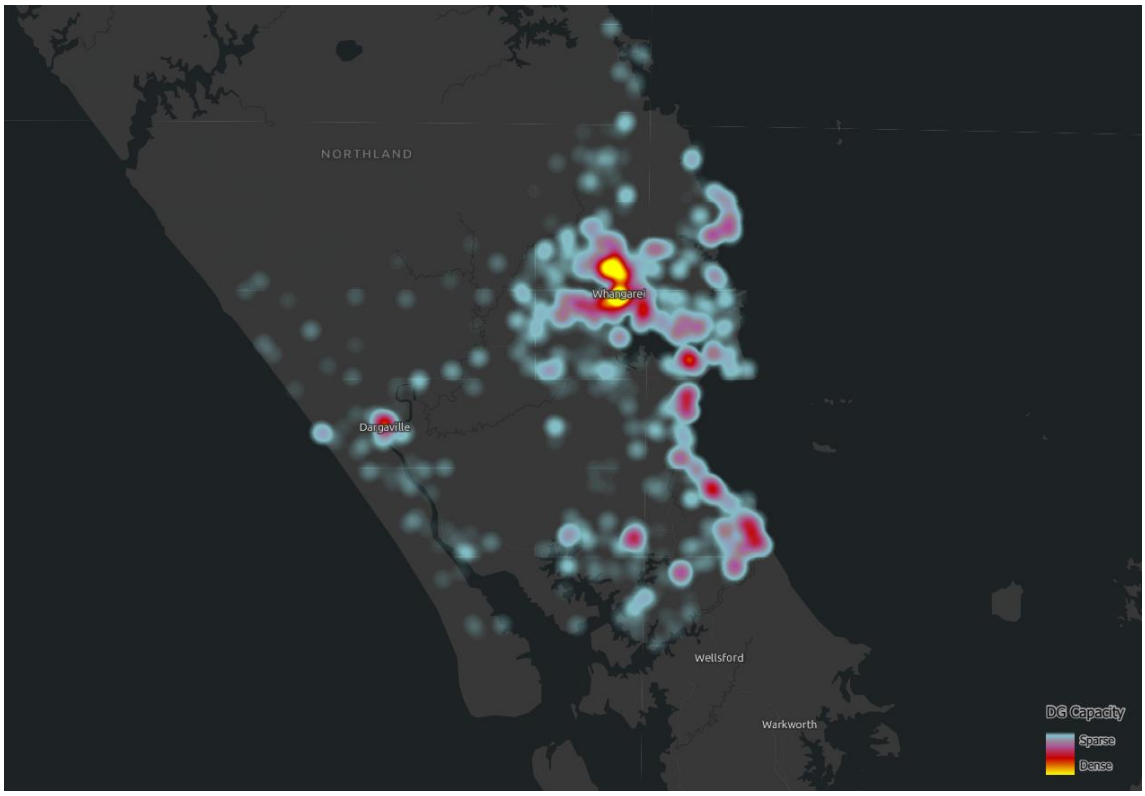
As of September 2022, there were 1,701 distributed generation systems with a total capacity of 24.2 MW connected to our network.

Table 8.9: Summary of distribution generation (data from Sepember, 2022)

OWNER	GENERATION TYPE	NUMBER	CAPACITY MW
Trustpower	Diesel	1	10
Northpower (Wairua)	Hydro	1	5
Private	Solar photovoltaic	1,698	9.2
Private	Hydro	1	0.015
Total		1,701	19.5

Solar PV generation has the potential to increase voltage levels above acceptable limits on 400/230V networks, as maximum output occurs during sunlight hours when loading on these networks is generally low. To accommodate 50% penetration of residential PV, it is likely that the capacity in the LV network will need to be increased to maintain voltage within limits, due to bidirectional power flows. For this reason, the number of connections of a distribution transformer may need to be limited, customer generation output curtailed at certain times, or network upgrades required before further connections can be made.

Figure 8.19: Heat map of current solar penetration on our network



The installed capacity on the network may be able to be increased by:

- reducing the voltage of the LV network, allowing more resilience to voltage rise
- increasing conductor size or reducing conductor lengths, reducing voltage drop and rise
- increasing the number of transformers in the network
- installation of voltage regulators with distribution transformers
- implementing line drop compensation at the distribution substation level
- exploring non-network alternatives.

Battery storage is now becoming more common with solar PV installations allowing off-peak generation to be used during peak periods, reducing adverse effects on the network.

Distributed generation is considered in our long-term planning process, and operating connections are monitored. As trends develop, data will be used to understand the impact on changing network demand and we will continue to model the potential impact of increased PV uptake, and develop plans to manage this.

Additionally, there is increasing interest in large-scale solar and wind generation sites across our network, requiring HV connections if they proceed. The majority of large-scale distributed generation applications are in more rural areas where network demand is relatively low.

8.8. Preparing for the future

As our customers' needs evolve and they adopt new technology such as electric vehicles and distributed solar, we also need to develop our approach to managing our LV network.

8.8.1. Case for change

In response to New Zealand's commitments to be carbon neutral by 2050, we are preparing for disruption to the electricity sector. With the decarbonisation of process heat and electric vehicles causing an uplift to electricity demand, along with the increase of distributed generation causing bidirectional power flow, our job as a distributor is to enable customers to adopt new solutions. Over the next 10 years we expect increasing:

- **Distributed generation**: customers self-generating and storing their own electricity from sources such as wind and solar, leading to electricity being fed back into the grid.
- **Advances in digital technology**: enabling increased control and information flow for customers to manage their energy use, and for new markets to emerge.
- **New consumption**: adoption of EVs and other technologies will create new demand for electricity. As batteries become more affordable, this will create greater flexibility to manage energy use, and more options to improve resiliency.

As these technologies become more accessible, our customers may wish to expand their energy choices, including:

- selling surplus energy into the market
- storing energy to either use when they want or to sell back into the market at a higher price
- developing neighbourhood storage networks
- charging their electric vehicles or devices at times when the cost of energy is cheaper
- lowering their energy consumption at peak times to reduce energy costs.

In recent years we have seen a rapid increase in electric vehicle uptake on our network. We are forecasting this trend to continue, driving the need to better understand our network's capabilities.

However, there is still a significant degree of uncertainty around the likely impact of decarbonisation. With the level of uncertainty it is currently not practical to heavily invest into accommodating these potential changes. Therefore, our plan is to improve our readiness to respond to these changes as they arise. We are working closely with our customers to understand their preferences and to understand how we can help them. We are also working towards a better understanding of our network's capabilities, particularly our LV networks. This will allow for a more dynamic approach with long-term planning.

8.8.2. Our journey

Adapting our network to accommodate changes in power flow and customer energy usage requires greater visibility and control of our network. Historically, our networks were planned with relatively predictable demand. Household consumption profiles and anticipated growth allowed for long-term investment planning with a fairly high degree of certainty.

We expect our LV network will see much of the change, due to the uptake of new energy technologies. Residential customers are fed off our LV network, and these new technologies give customers greater choice of when and how much electricity they want from the grid. With customer load profiles becoming more unpredictable, we can no longer rely on past assumptions. Making sure our LV network has sufficient capacity to enable customers the flexibility of service is central to our future network strategy. This will include integration of LV sensors, metering, and devices to gain visibility of our LV network.

At an aggregate level, large volumes of distributed generation and DER could impact our HV network. Our investment in upgrading our SCADA system and foundational elements of our advanced distribution management system is a key step towards moving to a more active distribution management system. In FY21 we implemented ADMS for our zone substations and subtransmission system and in FY22 we implemented it on our 11kV network. These more advanced systems will give us full visibility across our core network, enabling us to better manage capacity constraints.

To improve our network development approach over the next five years we will continue to:

- build greater visibility and modelling of our low-voltage network to enable proactive management of LV constraints
- explore new non-network solutions to ensure economic management of constraints on both the HV and LV networks.
- identifying opportunities to optimise operations as more DER is connected to our network.

These are discussed in more detail in the following sections.

8.8.3. LV network visibility and modelling

To build greater visibility and modelling of our low-voltage network, we are focusing on improving the data we hold on our LV networks and using this to more accurately model the networks. The following sections discuss this in more detail.

Modelling our LV network

During FY22 we carried out an initial modelling exercise of all of our LV networks individually. This was done using a mixture of real data stored in information systems and assumptions for missing data. Over time we aim to gather more data to validate our assumptions. This modelling exercise has given us a good understanding of what data we require and what areas we should be targeting for data capture.

We are working on importing our full GIS to our SINCAL interface for modelling and forecasting. This will increase the accuracy of modelling the LV network, DER uptake, and forecasting throughout our network.

Implementation of ESRI and integration with our GIS will enable us to create dynamic maps, providing website visitors with fast access to information about our network. This will include available hosting capacity for connecting large-scale distributed generation, as well as upcoming major project information and other useful asset location information.

LV network data

We have installed LV monitors on a selection of distribution substations. These monitors communicate through cellular connections to a cloud-based analytics package. The initial roll-out has targeted specific distribution substations which were expected to have the most benefit. These are in areas where we are seeing increased PV and EV activity, sites that will allow us to gain a better understanding of customer load behaviours, and areas that are most likely to have existing constraints.

Following our initial modelling exercise we have identified some asset data that needs to be improved. We are working on addressing gaps to improve the accuracy of our modelling.

We are working with other EDBs and metering providers (MEPs) to gain access to smart meter data from homes on our network. In FY22 we gained access to half-hour consumption data from 14,000 smart meters. This information will allow us to gain a better understanding of customer load behaviours and to validate our LV assumptions.

8.8.4. Non-network solutions

As discussed in our options analysis section, where increases in demand impact performance metrics (e.g. capacity, reliability, and security of supply), we consider both non-network and traditional network methods to address these issues.

As DER uptake increases and technology evolves, the opportunity to utilise these to provide more non-network alternatives is increasing. We continue to engage with industry parties and look for opportunities to leverage these resources to manage our constraints.

We have also noticed an increase in research and development across the industry to develop solutions to meet the challenges that come from connection of DER. We continue to explore these solutions and consider them as needs are identified.

8.8.5. Optimising operations

Within the next five to 10 years we anticipate operators will be able to interrogate near real-time information from distribution transformers and smart meters on our network. The ADMS outage prediction engine will use this information to speed up identification and location of faults on the network, enabling faster fault finding. We are also working on obtaining real-time information from smart meters that will help us with fault finding in outage scenarios, initially with ‘ping’ and ‘last gasp’ capabilities.

This information will support real-time modelling of distribution power flows within the network operations centre, improving decision-making. We aim to have the capability to support active LV operations management if it is required. Our customers will benefit from improved outage information on our website, which will also be available to our customer service representatives.

8.8.6. Innovation

We actively try to improve management and work practices across the business, adopting innovations where we can add value. We attend conferences and engage with other EDBs, either formally through groups such as the EEA and ENA or informally on particular problems. Recently Northpower has undertaken two innovation trials.

Line drop compensation

Distributed generation has the potential to cause voltage constraints on distribution networks. One of the main issues with distributed generation, such as solar, is the variability of generation throughout the day. This means its generation profile can be misaligned with load. As a response to the forecasted swing in voltage expected on some feeders, we are trialling line drop compensation at Parua Bay 33/11kV substation.

The line drop compensation trial addresses the variability of voltage throughout the day. Line drop compensation is typically a low-cost alternative to network upgrades, only requiring a change to the software in the relay controlling the tap changer. During lower loaded periods of the day, the line drop compensation will lower the substation 11kV bus voltage to allow for the increase of voltage caused by generation and raise the voltage during heavily loaded periods when the generation is not active.

The goal of this project is to economically improve the hosting capacity on the Parua Bay network to allow for more distributed solar to connect. The success of this trial will be based on our ability to manage the voltage within legal limits on this network. We will then look to implement line drop compensation across other areas of the network where this innovation can add value.

Stand-alone power system

We have implemented a stand-alone power system to supply a ranger's hut on Limestone Island, located in the upper reaches of Whangārei Harbour. Traditionally the rangers hut was supplied from a petrol generator. Due to the remote nature of Limestone Island, traditional electrical supply was not viable.

The stand-alone power system consists of a combination of PVs, batteries, and backup generation. Initial assessments of power usage found that most was used during daylight hours, which makes solar a good fit. When the batteries are fully charged, the solar inverter regulates the solar panel output to match the current energy loading requirements and avoid overcharging the batteries. If there is not enough solar energy or the batteries do not have enough charge, a petrol generator will operate.

The goal of this project was to acquire load data from the power system, allowing us to measure the reliability of a stand-alone power system of this nature and give us data to model future applications. The success of the project is based on the reliability of the system and the reduction of generation run time. For a typical week the generator only contributes 3.5% of the energy produced; this is a result of the generator's weekly 15-minute run test.

We will look to implement this solution elsewhere on the network where it can be a low-cost alternative to network upgrades.

Chapter content

9 Lifecycle Management

9. LIFECYCLE MANAGEMENT

9.1. Introduction

In this chapter we discuss our approach to maintaining and renewing our electricity network assets. It includes sections that explain our approach to managing each of our asset portfolios throughout their lifecycle stages.

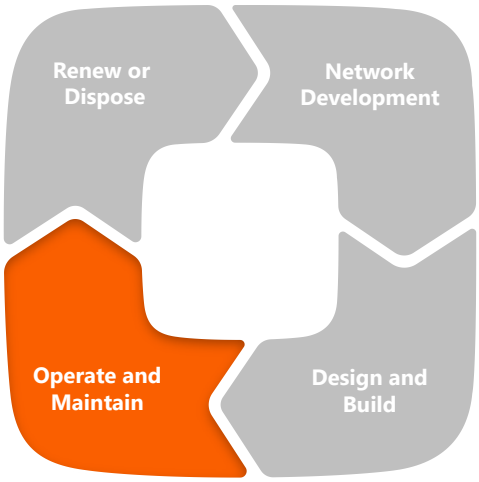
Our asset renewal programmes make up a large portion of our 10-year capex programme. Preventative maintenance inspections identify areas where renewal is required. Historical information also provides an indication of likely expenditure for any category where the preventative maintenance inspections do not identify any potential systemic issues.

We have started a transition towards condition-based asset management, which will lead to more optimal renewal timings for assets. To date, much of our renewal work has either been driven by fixing defects, addressing risks associated with deteriorating condition (e.g. copper and ACSR conductor replacements), or age-based replacement based on accepted industry standard asset lives. The renewal expenditure on the distribution network mostly includes poles, crossarms, insulators, fuses, and conductors.

We have begun a risk-based approach to proactively reduce the impact that vegetation has on our electricity network. We operate under the framework of the Electricity (Hazards from Trees) Regulations and work with landowners to secure effective vegetation clearance.

9.2. Operate and Maintain

As discussed in Chapter 6, we manage our network fleets using a lifecycle approach. 'Operate and maintain' is a key stage in this cycle. The figure to the right shows operate and maintain in the four lifecycle stages within our asset management system.



Operate and maintain lasts for an asset's life and impacts the timing and scope of other stages (e.g. the need for renewal). Our activities during the operate and maintain lifecycle stage ensure the asset's safe and reliable performance over its expected life. These include network operations (such as switching), maintenance, vegetation management, and spares management.

Effective asset management relies on appropriate integration between operations and maintenance and the other lifecycle activities, including network development, design, procurement, construction, and renewals. Once commissioned, assets are put into service and the operate and maintain stage begins. Many assets have a useful life exceeding 40 years, and the operate and maintain stage becomes an important and extensive phase of the asset's lifecycle.

The table below explains how effective operations and maintenance are important in ensuring our asset management objectives are met.

Table 9.1: How operations and maintenance supports our asset management objectives

OBJECTIVES	
Safety	The risk of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by following our safety, maintenance, and operational standards while carrying out operations and maintenance work.
Network performance	Reducing unplanned outages will improve reliability for customers. Increased preventive work will help reduce unplanned outages in the longer term by informing our renewal work. Reducing the duration of unplanned outages through improved reactive maintenance will improve the service experienced by our customers.
Supporting communities	Planned servicing is generally more cost-effective than unplanned repair work. Lifecycle costs can be reduced by carrying out an optimal volume of preventive work. By gathering better asset information, well-informed asset management decisions will help reduce whole-of-life costs and the long-term cost of service to our communities.

9.2.1. Network operations

The primary role of network operations is to ensure a reliable supply of electricity to our customers. We do this by managing the network in a way that ensures we consistently meet network, operational, safety, and asset performance objectives. Key activities include:

- real-time network control and switching
- network monitoring and event response
- planning for equipment outages to enable safe access to network assets.

Control rooms in our head office and in a separate substation are configured to allow the network to be controlled from either location, improving our network resilience.

Our operations team must consider factors such as how asset loading affects asset life and performance, and how to safely remove assets from service for maintenance while minimising service impacts. Operations activities provide feedback on network and asset performance and risk to the lifecycle planning process.

Spares management

Spare parts for our assets, stored in appropriate locations, help maintain reliable supply. We retain both strategic and critical spares. The number and type of spares retained for each asset varies depending on whether it is a subtransmission, distribution, or zone substation asset, and whether it is a new or legacy asset. Spares management can be complex for legacy assets as there are often many different makes and models in service, as in the case of switchgear. Standardising equipment manufacturer, type, and rating allows asset availability to be maintained with fewer spares, reducing holding costs.

We plan to further develop our approach to spares management, including developing formal spares strategies and plans for each asset fleet. These will apply a standard approach to determine the number and locations of critical spares, considering the expected impact of various equipment failures, the number of each asset type in service, and the risk each one represents.

9.2.2. Network maintenance

We undertake a range of maintenance activities to ensure our network assets operate in a safe and reliable manner throughout their lifetime. These activities include monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring service. Information gathered during maintenance activities is used to improve our asset standards and planning processes, and to inform our renewals programme.

Our maintenance activity is split into three types:

- **Preventive maintenance**: includes asset inspections, condition assessments, and servicing. These are typically carried out on a regular basis (for example, every three months, annually, or every six years) in accordance with our maintenance standards. Recorded condition assessment data is used for analysis, forecasting, and renewal planning. Defects and repair work (corrective maintenance) also arise from preventive maintenance.
- **Corrective maintenance**: this is planned work arising from preventive maintenance work, ad hoc identification of a defect, or as a follow-up to a fault (i.e. following service restoration). It includes defect rectification, repairs and replacement of minor components to restore the condition of an asset. Failure to undertake this work can reduce reliability and increase safety risks.
- **Reactive maintenance**: is work carried out in response to an unplanned event or incident that impairs normal network operation. Failure to undertake this work in a timely manner will adversely affect the service provided to our customers and may increase public safety risk.

Approach to maintenance

Our maintenance standards define preventive maintenance activities and the frequency at which these are to be carried out. Some inspections are non-periodic and are based on the number of operations or faults, a requirement to gather data for decision-making purposes, or on the criticality of the asset. We use this information to plan our corrective maintenance programme and inform renewal decisions. Key drivers of our approach include:

- **maintenance standards**: that specify recommended inspection tasks, servicing intervals, and reporting requirements
- **decision-making**: information on assets to make cost-effective, prudent decisions
- **legislative or regulatory requirements**: including frequencies for inspecting overhead line assets, or safety requirements
- **manufacturer's recommendations**: around inspection tasks and servicing intervals
- **asset condition**: as identified by preventive maintenance activities
- **incident numbers**: leading to reactive maintenance or corrective maintenance.

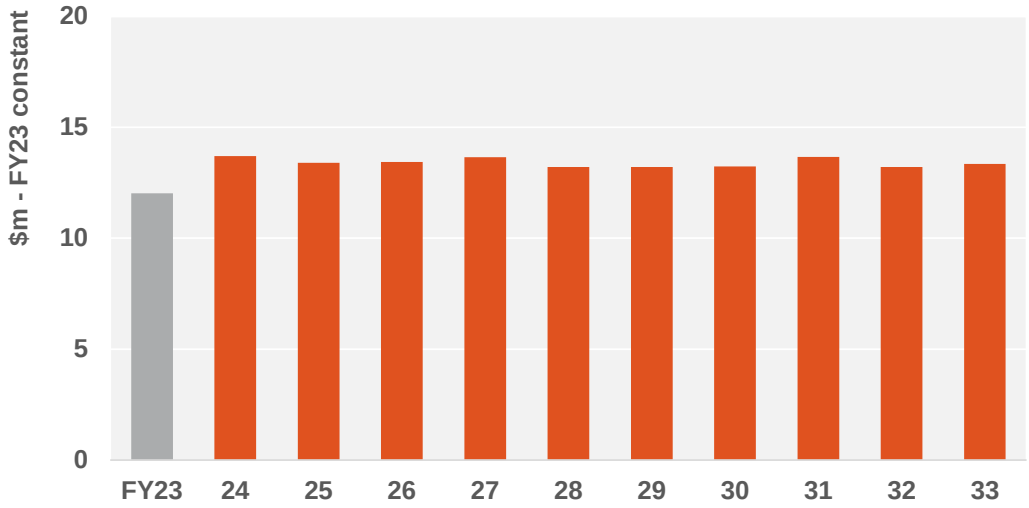
Our lifecycle approach requires us to make trade-offs between maintaining our assets in service (Opex) and replacing or refurbishing them (Capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life or defer renewal.

Details on specific maintenance activities are discussed in the fleet sections below.

Maintenance expenditure

The chart below shows our forecast maintenance Opex. Our expenditure requirement over the planning period is approximately $13.4 million per year.

Figure 9.1: Network Opex budget



Our maintenance forecasts consider historical costs, and we update these base amounts to reflect changes in strategy, known emerging issues with our asset fleets, and expected trends (e.g. anticipating fewer faults as the condition of the network improves). We then review preventive and corrective maintenance plans using a bottom-up approach, identifying work completed.

Benefits

The main expected benefits of maintenance over the planning period include the following.

- **Management of safety risk**: the risks of our workforce and the public being exposed to injury, and of damage to the environment, are reduced by following our safety and operational procedures while carrying out the work as scheduled.
- **Improved customer experience**: effective maintenance will help reduce unplanned outages in the longer term by informing our renewal work. Scheduled work is generally less inconvenient to customers and landowners than unplanned outages.
- **Reduced cost of works**: planned servicing is generally more cost-effective than unplanned remediation work. Lifecycle costs can be reduced by undertaking an optimal mix of proactive and reactive work.
- **Asset and condition information**: inspections provide us with condition information that allow us to make better informed asset management decisions. Some asset attribute information is missing, and preventive maintenance can confirm this data or gather it as required.
- **Improved decision-making**: by gathering better asset information, we can make well-informed asset management decisions to reduce whole-of-life costs.

9.2.3. Vegetation management

Left unchecked, vegetation growing close to our assets can have a significant impact on network reliability and public safety. Trees close to live conductors pose a risk of electrocution and fire to our communities. These events can also result in considerable damage to network equipment, causing network outages. Vegetation is one of the main contributors to unplanned SAIDI and SAIFI performance. Vegetation management is a key activity that enables our assets to perform to expected service levels.

We undertake vegetation management to keep trees clear of overhead lines. This is necessary to minimise vegetation-related outages and meet our safety and statutory obligations. The main activities are inspections to determine the amount of work required, liaison with landowners when work is required, and follow-up tree trimming and removal.

Effective vegetation management ensures we adhere to relevant regulations, including the Electricity (Hazards from Trees) Regulations 2003. These establish the rights and responsibilities for network owners regarding vegetation that encroaches overhead lines. The table below outlines how our vegetation programme supports our asset management objectives.

Vegetation-related faults are a significant contributor to unplanned SAIDI and SAIFI performance. Adverse weather events such as major storm events are a large contributing factor to vegetation-related faults.

Table 9.2: How vegetation management supports our asset management objectives

OBJECTIVES	
Safety	Minimise vegetation-related safety and environmental risks (e.g. fires). Improve education around risks associated with vegetation near conductors.
Network performance	Lower the risk of vegetation-related events damaging network equipment to reduce customer interruptions. Reduce planned outages by targeting vegetation trimming, and ensuring this work is aligned with other activities.
Supporting communities	Improve vegetation management efficiency and programme effectiveness to reduce vegetation-related faults and the cost of service to our communities.

Approach to vegetation management

During FY22, we reviewed our vegetation management performance and approach. This process identified that we have a backlog of vegetation work. and were not focusing on the areas that would have the greatest risk reduction for the network.

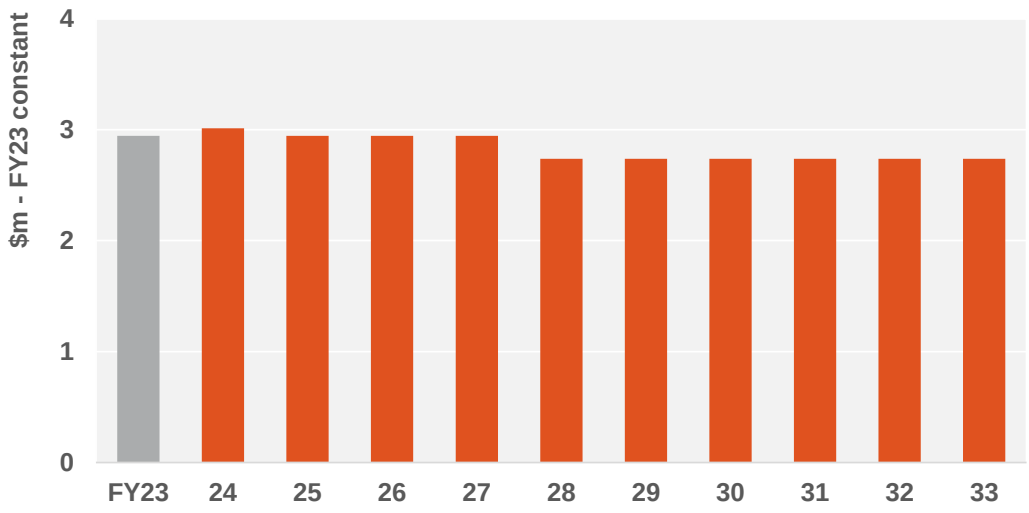
As a result of the review, we have moved from a cyclical, feeder-based vegetation management strategy to a risk-based vegetation strategy supported by rapid inspections. This will enable us to quickly identify vegetation work and focus on the highest risk work, as we work through our vegetation backlog. We also actively engage with landowners to get their agreement to remove vegetation that provides an elevated risk of interference with the network. We have begun to implement the new strategy and expect start to see the benefits of the new approach in the future.

To ensure the subtransmission network remains clear of vegetation, bi-annual, ground-based inspections are now complemented by annual helicopter surveys. These are focused on identifying risks from fall-zone trees and wind-blown vegetation debris.

Vegetation management expenditure

The chart below shows our forecast vegetation management Opex. The expenditure requirement over the planning period is approximately $2.8 million per year.

Figure 9.2: Vegetation expenditure forecast



The key expenditure drivers for the portfolio are:

- to provide a safe network for the public, our staff, and contractors
- to comply with tree regulations
- to reduce the risk of vegetation-related events damaging network equipment
- to provide a reliable network for our customers.

Benefits

The main expected benefits of vegetation management work over the AMP period are:

- **management of safety risk**: reduced risks of our workforce and the public being exposed to injury
- **improved customer experience**: fewer unplanned outages, improving network reliability
- **compliance**: ensures that the network is in full compliance with the requirements set out in the tree regulations
- **engagement**: increased stakeholder awareness around risks associated with vegetation near conductors.

9.3. Overhead lines

Box 9.1: Scale of cyclone damage yet to be fully quantified

As discussed elsewhere, at the time of publishing this AMP we had not undertaken any material analysis of renewal and network remediation need beyond that required to restore customer service.

We have not yet updated our expenditure forecast and plans following Cyclone Gabrielle in February 2023. We expect that the forecast presented in this AMP will require an update once we gather condition information of our network following the cyclone. The majority of the update is expected in our overhead lines portfolio as these are the assets that have experienced the brunt of the cyclone.

We are currently exploring ways of carrying out a condition assessment on our entire network so that we can quickly understand, and plan for, the impact the cyclone has had on our assets.

We need to understand the condition of our network following this event and may need to rebuild certain parts to restore a sustainable level of network condition. We are beginning to develop these plans and will include the required investments in future disclosures.

This section describes our overhead lines portfolio[27] and our fleet management plan. The portfolio includes three fleets:

- conductors
- poles
- crossarms.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches and provides expenditure forecasts for the planning period.

Box 9.2: Portfolio summary

We plan to increase our investment in overhead lines to an average $17.8 million per year over the period. We plan to gradually increase our expenditure from $6.9 million in 2023 to $22 million in 2032. This increase is gradual and reflects our ability to deliver the required renewal volumes over the next 10 years.

This increased investment is needed to address our ageing fleet of conductors and crossarms, supporting our safety and reliability objectives. Failure of these assets can significantly impact public safety risk and network performance.

This increase in renewals Capex is driven by the need to:

- keep up with renewal requirements for our ageing crossarm and conductor fleets
- address type issues, particularly with small diameter copper conductors
- continue to replace poor condition concrete poles and phase out wooden poles.

Overhead lines are a core component of our network. Adequate performance of these assets is essential to maintaining a safe and reliable network. Most of our overhead lines are in public areas; therefore managing our conductors and support structures is critical to minimise public safety risk, particularly in urban areas.

[27] All overhead lines Capex is covered under asset replacement and renewal information disclosure category, line items ‘subtransmission’ and ‘distribution and LV lines’, included in Schedule 11a in Appendix B.

9.3.1. Overhead lines portfolio objectives

Our objectives for the overhead lines portfolio are listed below.

Table 9.3: Overhead lines portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety	No fatalities and injuries from unassisted overhead lines failures. Downward trend in unassisted overhead line failures.
Network performance	Downward trend in unassisted overhead line failures. Minimise unplanned outages and supply interruption to customers. Minimise planned interruptions by coordinating with other works. Ensure network design standards are up to date and construct robust overhead lines to withstand climate change extremes where practicable.
Supporting communities	Consider options for alternative technologies and materials to reduce whole-of-life cost, e.g. remote area power systems. Continue to improve our condition assessments and collection to better inform our renewal forecasting approach, optimising whole-of-life cost.
Environment and sustainability	Ensure all materials are sourced sustainably. Wooden poles and crossarms are disposed of responsibly.

9.3.2. Conductors

Conductors are a core component of our network. We use a variety of conductor types across a range of voltages. Our conductor fleet also includes conductor joints, hardware, and fittings.

We have defined our conductor fleet according to their operating voltage:

- Subtransmission conductors (33 to 110kV)
- Distribution conductors (6.6 to 11kV)
- LV conductors (400V and below).

This approach reflects the risks faced, the criticality of the asset, and the levels of service expected; all of which vary with voltage. This means these factors may require different lifecycle strategies.

Conductors are typically located in public areas. Asset failures could result in conductor drops and injury to the public. It is critical that we minimise this public safety risk by maintaining the fleet in good condition.

Conductor fleet overview

Subtransmission conductors

Subtransmission conductors connect our zone substations to GXPs and generators at 33kV to 110kV voltages. We have a total of 324km of subtransmission conductors, of which the majority is aluminium clad steel reinforced (ACSR) type, followed by aluminium (Al) and a small amount of copper (Cu) type conductor, mostly on the Maungatapere lines.

Subtransmission lines typically cross private land on direct routes rather than following roadside corridors commonly used for distribution and LV lines. This can mean that

reconductoring involves extensive landowner consultation and consenting. Distribution and low-voltage lines can also be installed underneath subtransmission lines on the same poles.

Subtransmission lines are critical assets as they typically transfer more power compared to distribution and low-voltage lines. We typically design the subtransmission line network to have redundant (or N-1) supplies to our zone substations. This reduces the impact of the loss of any one circuit (in accordance with our security of supply guidelines outlined in Chapter 8).

Subtransmission conductors typically consist of larger conductor sizes and require higher clearances compared to distribution and LV lines. Our 110kV subtransmission conductors are supported by towers, which are typically 15–25m above ground. These influences renewal costs when comparing subtransmission lines to distribution or LV lines. The maintenance regime differs from other conductors.

Distribution conductors

Our distribution conductor fleet operates at 11kV, conveying electricity from our zone substations to distribution substations, which convert to 400V to supply our customers. Some customers connect directly to our network at 11kV. We own approximately 3,500 circuit kilometres of overhead distribution conductor, comprising ACSR, copper, and aluminium types. Distribution conductors make up ~70% of our total overhead circuit length.

Distribution conductors are supported by our overhead structures (poles and crossarms). The same structures may support a combination of distribution conductors, LV conductors, and service lines. Distribution over LV is a common pole and conductor configuration (conductors below others being termed ‘under-build’). Occasionally, multiple distribution voltage circuits may exist on the same poles, side by side or above and below.

LV conductors

LV conductors operate at voltages of 230V (line to ground), carrying electricity from our distribution substations to our customers and supplying power to streetlights. We own approximately 1,200 circuit kilometres of overhead LV conductor (including streetlighting circuits), which are primarily aluminium and copper types with a small volume of ACSR.[28]

LV conductors are supported by our overhead structures (poles and crossarms). Sections tend to be shorter in length than distribution conductor sections, due to voltage drop limitations. Many LV lines have a small number of customers connected to them.

At present, like most other EDBs, we have limited visibility of our LV network, in terms of both asset data and utilisation, compared to our subtransmission and HV networks. These constraints, in conjunction with the physical characteristics of LV networks, mean that we manage the LV network separately from other conductor fleets. LV conductors, like our other conductor fleets, have inherent public safety risk due to exposed live wires in the public domain that can fall to ground. Although they are of lower voltage than other conductor fleets, LV conductors have their own set of safety issues and considerations.

[28] Consumer lines that serve a single customer are not owned and operated by Northpower, so are not covered explicitly in any statistics throughout this document.

Population and age

The following table summarises our conductor population by type. ACSR conductors currently comprise 45% of circuit kilometres.

Table 9.4: Conductor circuit length (km) by type and voltage

CONDUCTOR TYPE	SUBTRANSMISSION	DISTRIBUTION	LOW VOLTAGE
ACSR	295	2,266	77
Aluminium	9	662	677
Copper	20	569	445
Total	**324**	**3,497**	**1,199**

The average age of our conductor fleet is 38 years, with subtransmission, distribution, and LV conductors at 52, 36 and 39 years respectively. ACSR and all aluminium alloy conductors (AAAC) are the main conductor types used in our overhead lines. Over the past 20 years, new lines have been constructed, mainly to keep up with system growth, with only minor replacement activities undertaken. Up to about 15 to 20 years ago, ACSR and copper conductor were mainly used in the construction of HV and LV lines. Since then, aluminium type conductors have become the preferred choice. The following chart illustrates the significant network expansion that occurred 40 to 60 years ago. Most of these conductor fleets are now approaching, or has reached, end of life.

Figure 9.3: Conductor age profile

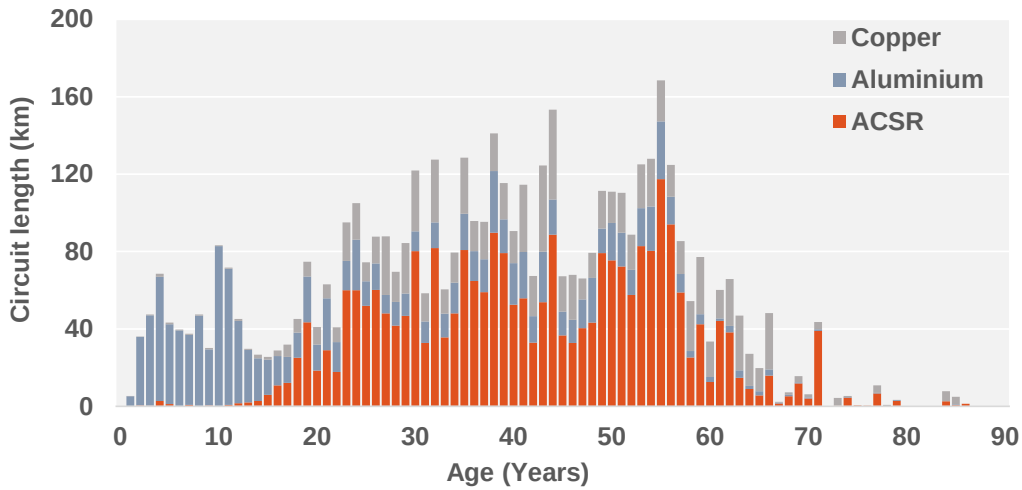


Table 9.5 sets out our conductors' expected lives. Note that this table applies across all voltages. Conductors of smaller diameter or located close to the coast have a shorter expected life. ACSR generally has a shorter expected life than other conductor types. ACSR conductors purchased before the mid-2000s had poor grease application quality control; many have patches with little or no grease. We refer to these as 'grease issues'.

Table 9.5: Overhead conductor expected lives

CONDUCTOR TYPE	SIZE (MM)	WITHIN 500M OF COAST	500M – 5KM TO COAST	>5KM TO COAST
Aluminium	<100	77	93	110
Aluminium	≥100	87	103	120
ACSR – grease issues	<100	38	53	74
ACSR	<100	48	63	84
ACSR	≥100	58	73	94
Copper	<100	55	67	80
Copper	≥100	65	77	90

Condition, performance, and risks

Managing the condition of our overhead conductor assets is critical to meeting our safety objectives. Asset failure can result in live conductors on the ground. Where the ground has high resistance, earth fault protection can have difficulty detecting faults, particularly if the conductor has landed on something other than the ground, such as a fence. Manual intervention by a circuit breaker operation following notification that a conductor is on the ground may be needed to de-energise the conductor.

Conductor failure can lead to loss of supply where there is N security. At subtransmission level, this is often not the case as the circuit will often comprise more than one line (i.e. N-1 security). However, at HV and LV levels, the circuit is commonly made up of a single line (i.e. N security) and loss of supply is the result. In most cases a back feed exists on the HV, but this usually requires a manual switching operation to restore supply.

To minimise public safety and network performance risk we aim to proactively inspect and replace overhead conductor prior to failure.

Condition

Overhead conductor condition assessment remains a challenge for the industry. A lack of visual defects does not necessarily mean the conductor is in good condition. Although our subtransmission conductor fleet is ageing, line failures are relatively rare due to its heavier, more robust construction.

We have recently conducted condition assessments on our 110kV subtransmission lines. These span from Kensington and Dargaville to Maungatapere. There were some minor issues with flaking rust on insulators and poor condition vibration dampers. Some conductor damage was observed, with lightning strike the suspected cause. These issues have been largely addressed.

Box 9.3: Meeting our portfolio objectives – network performance

Condition assessments on our 110kV subtransmission lines help to manage our failure risk on these assets. Early detection of issues allows us to address them before they fail and negatively impact network performance.

We have also recently carried out some conductor break tests on nine samples taken from our subtransmission lines. Of these samples, only one did not meet the strength threshold;

however, the current mechanical loading on this conductor is still within its tensile strength capacity. We will continue to assess this. The results of the sample tests were compared with our expected life assumptions and are currently within anticipated statistical bounds. We are expanding our conductor break testing programme to verify our expected life assumptions. We are primarily focusing on distribution conductors, given this is where are experiencing the most failures. The same conductor type (16mm2 copper) may also be used on LV, but our LV data quality is less robust.

Box 9.4: Improvement initiative – expanding our conductor break testing regime

To better understand the strength and expected lives of our conductor, we have been undertaking destructive break testing on conductors. These were tested to failure and compared with nominal rated tensile strength for their conductor material, along with other observations and tests. This testing is continuing and sampling will become more extensive, targeting conductors near the end of their expected lives.

This programme will improve our estimates of our conductors' expected lives by assessing actual strength and condition in order to improve our understanding of degradation. This information will also enable us to improve our asset health and forecasting models.

A network-wide sampling test undertaken in 2010 identified the presence of ACSR conductors suffering from grease issues. ACSR conductors have grease applied uniformly during manufacturing to provide a barrier to corrosion. However, if it is applied poorly, it is of little or even negative benefit. Grease application was poorly managed for conductors before to the mid-2000s and many conductors were ungreased before the 1970s.

The figure below shows the internal aluminium corrosion when grease has not been applied. In this case, the white aluminium corrosion product will gradually build up internally until the void space is filled, at which point bulging will occur. This reduces the strength of the conductor and may lead to conductor breakage.

Figure 9.4: Gopher ACSR conductor with grease issues

We are unable to identify grease issues from historic records and it would be difficult to identify these from visual inspections. However, as defects are uncovered through our inspections, we expect a higher proportion of these to be related to grease issues. We will replace these spans, rather than repair, when the defects are linked to greasing issues. We have estimated ~30% of our ACSR conductors suffer from greasing issues.

We undertook destructive testing on select samples of copper conductors. The samples consisted of conductors that were installed near coastal regions, high wind areas, and in urban areas. The samples were hard-drawn bare copper conductors, which were between 20 and 50 years of age at the time of testing.

The testing revealed that the copper conductors installed near coastal areas showed significant corrosion, with flaking[29] present and more than 10% reduction in tensile strength.

Figure 9.5: Copper conductor sample from a coastal area, showing corrosion

The figure above shows copper conductor sample that was installed in a coastal area. Approximately 50% of the cross-sectional area has been oxidised and easily flakes off.

The tests also revealed significant reduction in cross-sectional area in conductors installed in both coastal and high wind areas. This area loss means that the power and fault capacity of the conductors has been reduced and could easily be overloaded, resulting in the conductor breaking.

This test has highlighted an elevated failure risk for our copper conductor fleet, particularly if they are installed near the coast or high wind areas. This fleet is the focus of our renewal programme in the short to medium term.

Box 9.5: Meeting our portfolio objectives – network performance

By identifying high-risk conductor fleet materials, we can update our network design standards to construct robust overhead lines to withstand harsh environmental conditions and minimise unassisted overhead line failures and unplanned outages.

Performance

Our overhead network is designed to cope with defined environmental conditions such as certain wind loadings[30]. However, failures leading to conductor drops do occur, caused by the failure modes outlined below. This results in safety risk to the public and staff. We are working to improve our recording of outage cause data. We undertake follow-up

29 Flaking is a result of green oxides building up on the conductor. They can be easily flaked off when handled.

30 Note that the design standards many of these assets were based on have evolved over time.

investigations on all conductor incidents where we identify unassisted[31] failures. Knowing the root cause of a 'conductor down' event allows us to reduce the risk of recurrence.

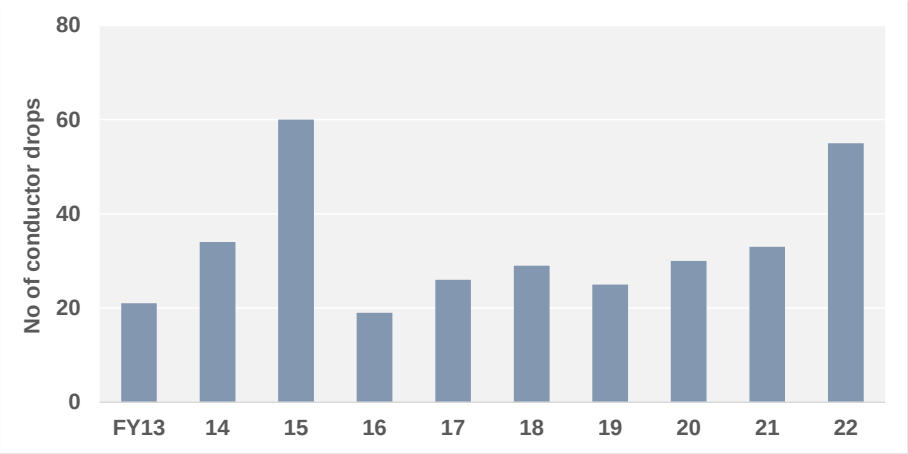
Table 9.6: Conductor failure modes

FAILURE MODE	DESCRIPTION
Corrosion	Corrosion occurs due to a chemical or electrochemical reaction between the conductor material(s) and its environment. The conductor deteriorates and loses strength. A higher rate of corrosion can occur if the conductor is close to the coast where water containing sea salt will likely penetrate the conductor. The sea salt gradually builds up inside the conductor and promotes corrosion when dissimilar metals are present (ACSR), or causes severe pitting in aluminium conductors.
Oxidation	When exposed to oxygen, a hard and resistant oxide coating forms on aluminium conductors, which reduces conductivity and makes working on it difficult. Some aluminium alloy conductors develop severe pitting and white corrosion, leading to a reduction in strength, when they are located close to the coast or near industrial plants. Some aluminium alloy conductor types are more brittle than others, leading to working difficulties and a higher chance of early failure from aeolian vibration.
'Grease issues' / Galvanic corrosion	This is applicable to ACSR conductors that have grease inconsistently applied during manufacture. This is prevalent in certain batches, manufactured during a particular period. Ungreased or 'grease holiday' conductors cause accelerated corrosion through galvanic cells forming due to dissimilar metals (aluminium, steel, and zinc), particularly if the conductor is located in salt-laden environments (i.e. coastal areas).
Bulging	Bulging is evidence of corrosion greater than 8% of cross-sectional area. Bulging is observable through both an increase in measurable conductor diameter, and discoloration of the line (white aluminium hydroxide).
Fretting	Fretting causes accelerated rates of degradation. Fretting is caused by rubbing between conductor strands and is associated with high conductor movement and lack of grease.
Fatigue	Fatigue occurs at locations of high conductor stress and cyclic load. Fatigue develops progressively and is not generally detectable with in situ visual inspection.
Annealing	Annealing occurs due to high temperatures (>100 degrees C) over an extended time period. Annealing reduces the yield strength of the conductor, and can be seen as changes in colour and sagging due to creep. Annealing reduces the ability of the line to withstand design loads and extreme events such as storms.
Vegetation, wildlife or lightning	Clashing of adjacent conductors or foreign object strikes (vegetation, birds) or lightning strikes can cause mechanical damage leading to loss of tensile strength.
Small diameter copper	Small diameter copper conductor is less durable than other types when it ages, simply based on its size. The loss of strength in even a small number of strands has a large impact on the strength of the overall conductor.

The number of conductor drops per year has been consistent over the past 10 years, as shown below. Noticeable spikes occurred in 2014–15 as well as in 2021–22. Vegetation was a major contributor, with twenty-one conductor drops caused by tree contact, while eight were caused by vegetation blown into lines during adverse weather conditions. Another 10 incidents were attributed to metal fatigue and poor connection.

[31] An unassisted failure occurs when the asset fails, even though the mechanical loading forces being applied on the asset were within the original design strength capacity.

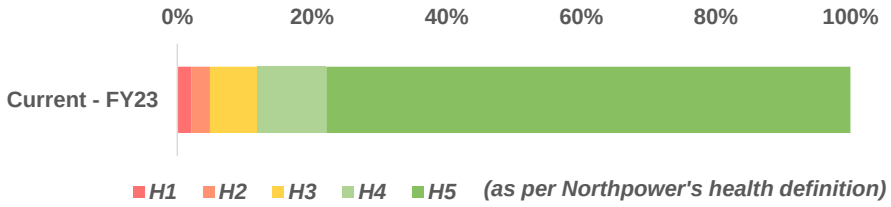
Figure 9.6: Overhead conductor drops



Asset health

Conductor asset health is based on expected remaining life and considers the conductor's type, size, and location. Life expectancy is represented by a normal distribution for each expected life grouping. This approach is considered more robust than simply assuming equipment fails at a particular age.

Figure 9.7: Conductor current asset health



We expect to replace 12% of conductor lines over the next 10 years. The expected replacements mainly comprise copper and ACSR type conductors that have reached their expected end of life.

Risks

The table below sets out a high-level summary of the key risks and mitigations we have identified in relation to our conductor fleets. They apply to varying degrees across all voltage levels. We are managing and mitigating these risks to the extent possible, including improving our understanding of condition through sampling and destructive testing, and managing condition through our renewal programme.

Table 9.7: Conductor failure risks

DESCRIPTION	RISK MITIGATION	RISK TYPE
Conductor failure resulting in lines down or conductor drop to ground	Inspection regime and conductor break testing Proactive replacement of conductor sections Proactive replacement of joints and fittings Standardisation of equipment Training and educating lines workers on usage and installation of joints and fittings	Safety, network performance
Conductor floating, due to failure of fittings and joints	Inspection regime including poles, crossarms, fittings, and joints. Proactive replacement of conductor sections	Safety, network performance
Conductor overload, causing sag and potential for electrocution and fire.	Operating procedures, MDI readings, network planning, and subsequent work Replace small conductor at risk of insufficient fault-handling capability.	Safety, network performance
'Low' conductor spans / non-compliant conductor clearances, elevating risk of contact with people, property, or livestock	Pole and conductor inspections or 'ring-ins' identifying low spans. Future: discussions with road owners about road level increases	Safety
Conductor flashover due to tree contact	Vegetation management programme	Network performance
Third party and wildlife causing conductor damage	Permit processes, public safety programmes, and inspection regime	Safety, network performance
Accidental breach of safety clearances to live conductor, causing flashover	Safety programmes, first vegetation cuts, inspection regime	Safety

Design and build

All our overhead lines are designed using AS/NZS 7000 and related national standards such as NZECP34. The standards detail the design principles for overhead reticulation before and beyond the zone substation and up to the customer's point of connection. The design aims to minimise the amount of impact on landowners and the public. Conductor renewal is dependent on pole design, so we consider these together (as line design). Many poles usually require replacement on reconductoring projects.

We consider electrical, mechanical, environmental, economic, and standardisation factors across the network when determining the size and type of conductor. In most cases we tend to choose AAAC conductor due to its high conductivity and low tendency to corrode. ACSR is our preferred option when we have long spans or high loading scenarios. We limit ACSR installations near the coast because corrosion can significantly reduce ACSR lifetime. We also allow for 11kV lines to be run underneath subtransmission lines.

Climate change could influence overhead line design and construction standards. Higher ambient temperature could cause conductor sag, while more frequent and intense storms could lead to increased failures. As these events become more common, design standards and principles may be adapted to accommodate the changing environment.

Council requirements impose height restrictions for conductors in certain areas. When subtransmission conductors are due for replacement, we take these height restrictions into account. If we are unable to meet these height restrictions while maintaining safe clearances, we will assess the feasibility of rerouting or undergrounding the line.

Subtransmission conductor design is typically outsourced as they are more complex compared to distribution or LV lines. We have an in-house design team who fulfil a range of roles, from scoping, project engineering, and contractor design support through to standards development. Overhead conductor work is carried out by our contracting division. We have in-house quality assurance staff who undertake an audit of contractors' completed works.

Operate and maintain

Preventive maintenance

Overhead conductor maintenance and inspection regimes typically include visual inspections. Preventive maintenance and inspection tasks are summarised below. Conductors do not typically require routine maintenance. Due to wind-induced vibration and movement, as well as thermal cycling, they corrode and work-harden, becoming brittle. Intrusive inspections are typically done on a five-yearly basis to assess condition and support renewal decisions.

Table 9.8: Conductor preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Helicopter inspection of subtransmission conductors. This is a visual inspection which picks up defects such as broken strands and signs of clashing. We also use infrared cameras to pick up overheating issues with loose terminations/joints	Yearly
Ground-based visual inspection of conductors as part of overhead network inspections which include conductor clearance checks and basic condition observations	Five yearly
Break testing conductors to the manufactured standard. We test multiple samples, which then gives us a better picture of the line's strength and its future performance under loads	Ad hoc

Corrective maintenance

Corrective maintenance includes repairing conductor sections by removing damaged sections and replacing them with new ones.

Reactive maintenance

We undertake reactive maintenance on conductors when responding to faults which may be caused by conductor or fittings failures, adverse weather, or vegetation contact. To ensure we respond to faults in a timely manner, we maintain sufficient spares at strategic locations.

Spares

We store spares for most conductor types in our warehouses/depots. As many of them are very old and we have a wide variety installed across the network, to ensure a reliable service we often choose conductors of similar size if the required type or size is not readily

available. Along with the conductor spares, we also maintain stocks such as fittings, joints, and other standard components.

Box 9.6: Meeting portfolio objectives – network performance

Having stock on hand allows us to act quickly to remediate unplanned outages and minimise disruption to our customers.

We are standardising our conductors to AAAC. This will help reduce the range of conductors on the network, which in turn will mean less hardware is required in stock for spares.

Renew or dispose

We trigger a review for conductor replacement based on age (versus expected life), as a proxy for condition. The review involves conductor sample testing to determine remaining strength and a follow-up with replacement where necessary. For known conductor-type issues, sample testing is usually not necessary (such as copper conductor). Our conductor forecasts include all replacement poles and pole-mounted equipment that are undertaken on the reconductoring project.

Table 9.9: Summary of conductor renewal approach

ASPECT	APPROACH USED
Renewal trigger	Age (versus expected life) and follow up condition assessment
Forecasting approach	Repex modelling
Cost estimation	Volumetric

Renewals forecasting

We use a Repex[32] approach to do the forecasting for the conductor fleet. The Repex methodology applies a normal distribution in expected life across the fleet. The use of a distribution reflects that statistically not all assets will require replacement at their stated end of expected life.

Our conductor life expectancies are based on trends observed in the industry. We will carry out more conductor sampling to verify these expected lives as discussed in earlier sections.

Our unit rates are based on our expected average cost to replace 1km of conductor, which includes the poles, crossarms, and pole-mounted equipment. The pole-mounted equipment could be replaced because of either poor condition or where it does not have the strength or capacity required to support the new conductor. These unit rates also differ by voltage, as the equipment and work are generally more expensive the higher the voltage.

Options analysis

We typically replace conductor spans or line sections rather than the entire line. However, if most of the line is in poor condition, particularly if they were all built in the same era and

[32] Repex refers to replacement expenditure and is based on a modelling technique typically used by Australian utilities and endorsed by the Australian Energy Regulator (AER).

use the same type, then it is likely we will consider rebuilding the entire line. As such, we will consider options analysis, taking into account the following, but not limited to:

1. The condition of the support structures, i.e. poles and crossarms, and whether they will need replacing or if they can be reused. If the majority of the support structures require replacement, it may be cheaper to reroute the line. Rerouting the lines also reduces the impact of a prolonged outage compared to replacing in situ.
2. If the renewal need is combined with forecast growth, we often replace with a larger size conductor. This tends to require new poles to support the increased weight.
3. Undergrounding the existing line, particularly if we know a new development is proposed, or if it currently routes through heavily populated areas, or it is in a fault-prone area where trees cannot be cleared effectively.

We have previously undertaken options analysis using a qualitative approach; however, we have recently developed a quantitative method which will be used in the future. This new quantitative approach considers a wide variety of factors like whole lifecycle costs, growth options around the region, and network security risk.

Underbuilt conductors are considered for renewal with the distribution/subtransmission conductors, subject to their age versus expected life and economic efficiency of consolidating works.

Easement considerations are important when considering options, as this can significantly affect project timing and budget. Where possible we aim to use existing use rights; however, this is not always possible.

Use of criticality in works planning and delivery

Conductor projects, if large, generally have detailed quantitative studies which consider site specific analysis of costs and loads at risk. Criticality in works planning and delivery is more applicable to distribution and LV conductors which are assessed on a span-by-span basis.

Disposal

When conductors are removed, they are typically in such a degraded condition that reuse is not an option. Removed conductors are scrapped.

Coordination with other works

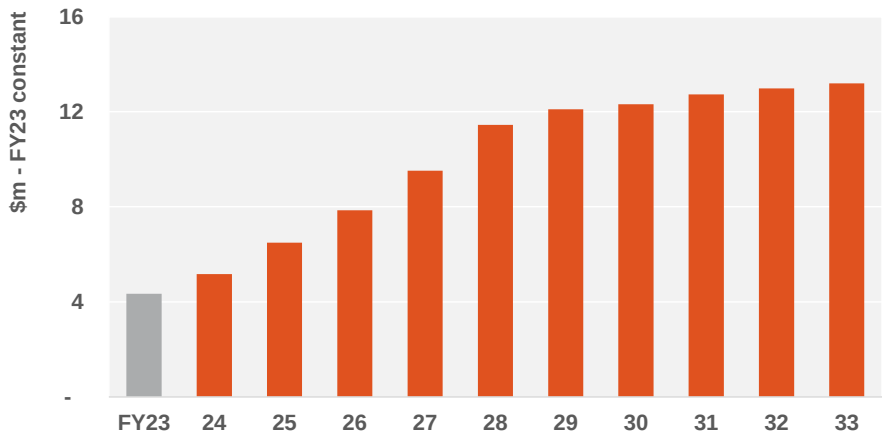
Conductor replacement drivers may be combined with load growth. If a conductor requires replacement in the medium term, forecast load growth[33] will be considered. The preferred solution may be to replace with a larger size conductor. In the case of a like-for-like ampacity conductor, it may also increase the loading on support structures (e.g. copper is smaller per ampacity than aluminium, so aluminium is lighter but has higher wind loading due to increased surface area). When we plan to replace conductors, we make sure that the support structures have sufficient mechanical load carrying capacity as per the latest standards.

[33] Analysis of future load growth in the area(s) supplied by subtransmission circuits, security of supply requirements, and network contingency scenarios are further discussed in Chapter 8.

Conductor expenditure forecast

We have forecast conductor renewal Capex of approximately $103.8 million during the planning period.

Figure 9.8: Forecast conductor Capex



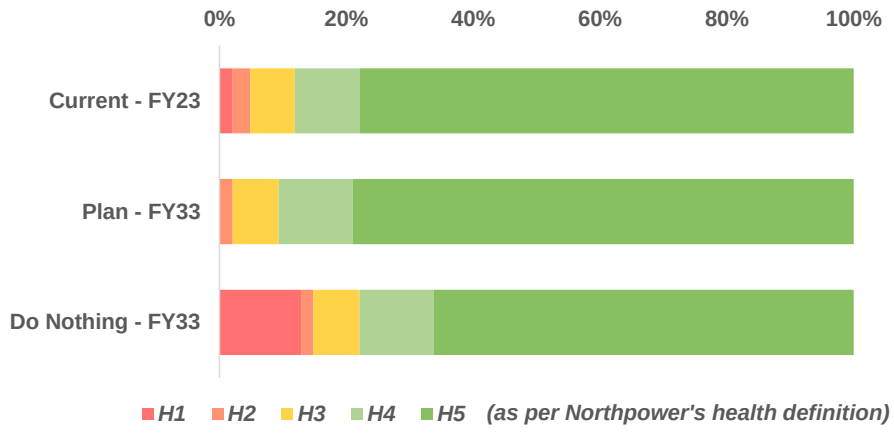
Historically, we have replaced conductors reactively, driven by conductor failure or damage, and at a relatively low rate. We are transitioning to a proactive replacement approach and expect this gradual increase to better manage the health of the conductor fleet.

Benefits

The key benefits of our planned conductor renewal programme are that there is an overall improvement in the asset fleet health, a reduction in public safety risk and maintain network performance. This is key to meeting our safety and network performance asset management objectives.

The figure below compares our projected asset health in FY23, following our planned programme of renewals, with a counterfactual do nothing scenario. This comparison indicates the benefits provided by our proposed investment programme.

Figure 9.9: Projected conductor asset health



Our proposed level of investment will improve overall fleet health, helping manage the risks associated with conductor failure. In the hypothetical do nothing scenario, 13% of our fleet, as depicted by the H1s, will be at risk of failure by FY33, leading to heightened public safety and network performance risk.

9.3.3. Poles

Pole fleet overview

Poles and crossarms are key components of our network. Combined with overhead conductors, they make up our overhead network that connects customers to the transmission system and enables electrical flow at various voltages. Poles also support distribution transformers, air break switches, and third-party assets such as streetlights, communication assets, and road signs. Figure 9.10 shows typical examples of our pole fleet.

Figure 9.10: Concrete poles - single pole (left) vs double pole (right) structure

Our poles fleet mainly consists of concrete poles and a relatively small number of wooden and steel poles. We have approximately 54,000 poles on our network. We also include our 48 transmission towers in this fleet.

Concrete poles

We have two types of concrete poles on our networks – pre-stressed and mass reinforced. Pre-stressed poles are manufactured with tensioned steel tendons (cables or rods). They are a mature technology and generally perform reliably over a long period. Most of the new poles we install are pre-stressed concrete. They are designed and manufactured to meet stringent structural standards. Pre-stressed poles are relatively robust against common concrete pole failure modes, e.g. cracking and spalling.

Mass reinforced concrete poles contain reinforcing steel bars covered by concrete. They were regularly used from the 1960s to 1980s, but only infrequently since then. We now prefer to install pre-stressed poles as mass reinforced tends to crack easily, which allows water ingress and eventual corrosion of the steel bars.

Wood poles

The wooden poles in use on the network are largely hardwood. Wood poles are no longer used for new lines or as a replacement for existing poles. Wood pole performance and expected service life is generally poor compared with concrete poles. This is why we prefer to use concrete poles.

Steel poles

We have a small handful of steel poles in our fleet. These are mainly tubular-type steel poles, which are commonly used for supporting streetlights. In the past, we have installed these poles in very difficult terrain. They are manufactured in tubular sections, which makes them easy to transport and install.

Most of these poles were installed without a concrete foundation i.e. they have been directly embedded into the ground. We suspect this has caused significant corrosion to the steel below ground due to moisture ingress. Some of these are located close to the coast, exposing the steel to accelerated salt and moisture corrosion. We have abandoned the use of steel poles in favour of installing concrete poles, as they are expected to last longer.

Towers

We have one 110kV circuit which runs from Kensington to Maungatapere and one 50kV circuit from Dargaville to Maungatapere, which are both supported by towers. These towers are galvanised steel lattice structures, mounted on concrete footings. These towers are generally more complex than poles, comprising numerous components, such as steel members, bracers, attachment points, anti-climb hardware, lattice crossarms, signage, earth wire hardware, and insulator strings. Towers are connected to their concrete footings with baseplates. The concrete footings contain reinforcing which provides the structural strength to withstand the compression and lifting forces from the tower. The concrete footings also have an engineered earth grid surrounding the footings. This minimises hazardous step and touch potential, and voltage rises when a fault occurs on the tower. We maintain specific access tracks to these towers, which are used for maintenance and other planned work.

We also have two relatively large steel monopoles that support subtransmission lines. These are installed with engineered concrete foundations. Figure 9.11 shows the tower types.

Figure 9.11: Transmission lattice tower (left) and steel monopole structure (right)

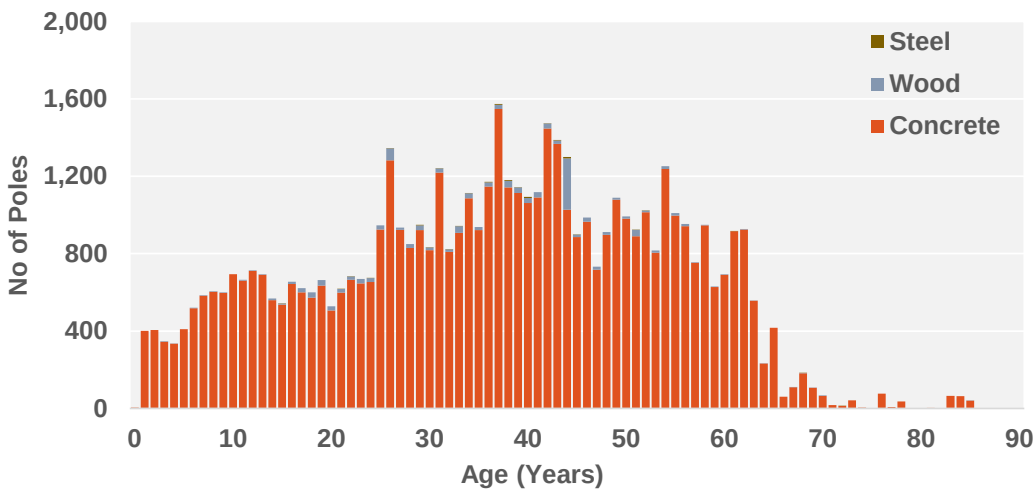
Population and age

The table below summarises our population of poles by type. Concrete poles currently make up most of our poles (98%). In addition to our poles, we have 48 lattice towers.

Table 9.10: Pole population by type

POLE TYPE	NO OF POLES	PERCENTAGE
Concrete	53,504	98%
Wood	1,165	2%
Steel	49	~0.1%
Total	**54,718**	**100%**

Figure 9.12: Poles age profile



Our concrete pole fleet is relatively young, with an average age of 37.5 years old. Their expected life is 80 years. In contrast, the average age of our steel poles is ~40 years old, and a large number of these have now exceeded their 30-year expected life. Our wooden pole fleet is approaching their 50-year expected life.

The subtransmission towers for the KEN-MPE line were first commissioned in 1975 and the DAR-MPE lines were constructed in 1993.

Condition, performance, and risks

As with the conductor fleet, managing the condition of our poles is critical in meeting our safety and network performance objectives. When a pole fails in service, this presents a significant safety issue. It potentially exposes the public or our workers to hazards associated with falling equipment and live conductors on the ground or at unsafe heights. Typically, a pole failure will also result in loss of supply.

To minimise public safety and network performance risk, we aim to proactively inspect and replace poles prior to failure.

Condition

Our poles, other than steel and wood poles, are in relatively good condition overall. Historically the level of identified red-tagged poles[34] has remained relatively low, especially concrete poles. The majority of identified red-tagged poles are wood poles. We have been replacing these poles within the legislated time frame of three months.

Our condition-driven concrete pole replacements are relatively few and mainly relate to spalling and cracking. Concrete poles tend to spall as they reach the end of their life. Spalling is where the internal reinforcing steel begins to corrode and swell, which causes the concrete to crack and break off in chunks, which then allows more corrosion. Minor spalling does not reduce the strength of the pole significantly, but we want to prevent concrete from failing as that creates a safety hazard.

A larger proportion of our wood pole fleet, relative to concrete poles, is deemed to be in poor condition, based on our visual inspections. We are in the process of verifying the structural integrity of these poles, which may include undertaking ultrasonic measurements of the extent of decay to determine if these need to be replaced.

As discussed previously, our steel poles have been installed in ways that would not meet our current design standards. We suspect a large portion of these steel poles, particularly ones close to the coast, are in poor condition. Where the steel poles have been directly embedded into the ground, we expect some significant corrosion, which could compromise the poles' structural integrity. It is also difficult to assess the corrosion of the steel below ground or on the inside, but we are currently exploring options to do this work.

Condition assessment of our towers was undertaken in 2021. The towers were assessed to be in reasonable condition, with most of the components rated 40–50 condition[35]. Key issues with these towers were mainly rusting foundation bolts, insulator attachments,

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34 A red tagged pole means the pole is in poor condition and is identified as high priority for replacement. It is required to be replaced within three months of identification.

35 The condition rating ranges from 0 to 100 where a condition rating of 20 or lower will require intervention.

insulator pins, earth wire attachments, and cold/hot end suspension hardware. All these issues have now been rectified through corrective maintenance and replacement.

Performance

Poles are generally located in public areas, so failures are a risk to public and personnel safety. We design poles so they can withstand the mechanical forces applied to them both by the equipment we have mounted on them and by expected external forces such as wind.

We are improving our outage data to accurately record unassisted pole failures. Historically, pole failures have been relatively low and have not led to any major public safety incidents.

Box 9.7: Improvement initiative – improved outage data capture

As part of our data improvement journey, we are improving the way our outage data is categorised and captured to include detailed information about problems, causes, and remedies. This will enhance our future failure and cause analysis to be able to identify corrective actions and improve the performance of our fleet.

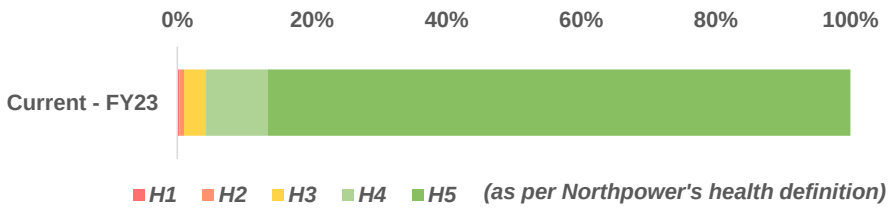
Box 9.8: Meeting our portfolio objectives – public safety and network performance

Identifying the cause of unassisted failures allows us to carry out corrective actions to our overhead network to lower public safety and network performance risk.

Asset health

We have estimated our pole fleet's asset health based on expected remaining life, e.g. 80 years for concrete poles. Life expectancy is represented by a normal distribution, which is considered as a more robust approach compared to simply assuming the pole failing at a particular set age.

Figure 9.13: Poles current asset health



Current asset health shows that we only expect to replace 4% of poles over the next 10 years. This is because the fleet is in relatively good condition.

Risks

The table below summarises the key risks we have identified for poles.

Table 9.11: Pole risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
Pole failure due to poor condition or slip failure	All	Visual inspection and/or proactive replacement	Safety, network performance
Concrete spalling and falling	Concrete poles	Visual inspection and/or proactive replacement	Safety, network performance
Assisted pole failure due to conditions that exceed design limits, e.g. extreme weather events, or vegetation onto line causing pole failure	All	Network planning/design, contingency planning, vegetation management and first response approach	Safety, network performance
Outages or failures caused by a third party	All	Increase public awareness on safety risks, relocating poles	Safety
Vermin-caused outages	All	Install possum guards / vermin deterrents on poles	Network performance
Tower footings compromised due to slips	Towers	Routine visual inspection and engineering assessment of transmission lines after major storm events	Network performance
Tower failure due to poor condition	Towers	Condition assessments and proactive replacement of components and corrective maintenance	Network performance

We are managing and mitigating these risks where practical, including ensuring all poles are inspected within the legislated time frames and proactively replacing poles in poor condition.

Design and build

We design our poles to mechanical loadings and clearances in accordance with NZECP34 and AS/NZS 7000. Newly installed poles typically have more mechanical loading capacity or better capability than the poles they replaced. Our current preferred pole type is pre-stressed concrete, which has the lowest overall lifecycle management costs compared to other types. The physical placement of poles is important when considering historical frequency of car accidents on poles. If possible, we will locate them further away from roads/highways that are prone to accidents. We have in-house resource that provides design services while our contracting team carries out the replacements. There may be select cases where external resources are used for more complex designs and builds.

Our transmission towers and monopoles are engineered to specific site requirements, considering soil conditions, height restrictions, and landowner requirements. Typically, external resources will be used for engineering review and design services. Our contracting division is well equipped to install / repair / refurbish towers as required.

Operate and maintain

Our maintenance activities for overhead support structures are listed below.

Preventive maintenance

We inspect and test poles and undertake condition assessments for towers on a periodic basis. It is critical to regularly inspect all poles and towers because they may be damaged or compromised by an external party, land movement, deteriorating condition, or extreme weather events. Our preventive maintenance tasks are set out as follows.

Table 9.12: Pole and towers preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	TYPE	FREQUENCY
Transmission towers and monopole condition assessments	Towers	Two yearly
Visual inspection, including other pole-mounted equipment such as distribution transformers and switches	Poles	Five yearly
Ultrasonic scan of wood poles to determine extent of decay	Wood poles	Five yearly or when identified via visual inspections

The pole visual inspection frequency is based on the legislative time frame set out in NZECP34:2001. Where issues are identified, we may undertake further investigation before we decide to take further corrective action or replace the asset.

Corrective maintenance

We undertake corrective maintenance on poles to repair or replace components of poles such as guy wires, bolts, and installing possum/cable guards. For the foreseeable future, we do not anticipate any uplift in corrective maintenance activities.

Box 9.9: Improvement initiative – consumer poles

Electricity regulations require that consumer poles and conductors installed before 1984 are in a “reasonable standard of maintenance or repair” before ownership is transferred back to customers.

We are working to gather information on consumer poles to establish the degree of inspection coverage across these poles and their compliance with the regulations.

Once an overarching strategy is determined to resolve the risks with consumer poles, we will assess the impact on expenditure in the future.

Reactive maintenance

Reactive maintenance on poles is the response to faults and failures. These may have been caused by extreme weather events or by an external party, such as car accidents. If reactive maintenance involves replacing the entire pole, the cost of the pole replacement itself, excluding first response cost is capitalised.

Spares

Poles are standard equipment and stock is kept in our warehouses. These are located strategically around our network, allowing timely fault response. Our supplier also keeps a range of concrete poles in stock.

Renew or dispose

We replace poles when they are in poor condition or if they are below the strength requirements of a new conductor being installed. The latter will trigger an engineering review to ensure design standards are met.

Our preventive maintenance inspections identify poles for replacement. We have a targeted programme to replace wood poles with concrete poles as they reach the end of their serviceable lives. We also focus on identifying and replacing spalling concrete poles.

Table 9.13: Summary of poles renewal approach

ASPECT	APPROACH USED
Renewal trigger	Proactive condition-based Reconductoring projects (forecast under conductors' fleet or growth portfolio)
Forecasting approach	Repex modelling Average poles replaced from planned reconductoring projects (forecast under conductors' fleet or growth portfolio)
Cost estimation	Volumetric

Renewals forecasting

We use a Repex approach to forecast pole replacements. The Repex methodology applies a normal distribution of the expected life across the pole fleet. Our poles' expected lives are 80/30/50 years for concrete/steel/wood poles, respectively. Longer term, we intend to improve our forecasting methodology, either to be condition or survivor curve based once we have improved our asset data collection process and inspections.

Our unit rates are based on the expected average cost to replace a pole together with the crossarm assembly, the occasional pole-mount equipment, and a section of conductor.

Options analysis

We consider the following options, which include both capex and opex trade-offs, to determine the lowest overall cost approach when managing pole risks.

- **Replace**: poles that are in poor condition or do not have the strength requirements to support existing or new conductors are replaced.
- **Repair**: we repair or replace pole components, such as guy wires, bolts, signs and guards if they are in poor condition.
- **Relocate**: if a pole location has a history of vehicle versus pole accidents we may consider relocating the pole to a safer location. Note that customer driven/funded relocation is covered under asset relocation Capex.
- **Undergrounding**: we may consider undergrounding poles and associated lines that are in poor condition where modern clearances cannot be feasibly met, or if district or council requirements do not allow it. Note that customer driven/funded undergrounding is covered under asset relocation Capex.

- **Overhead to ground-mounted substation conversion**: we are phasing out pole-mounted distribution transformers installed on platforms between two poles. This is due to safety concerns while carrying out work at height. These transformers are typically >100kVA. When they are due for renewal, they will be converted to ground-mounted equivalents and the associated poles will be removed from service.
- **Remote area power system**: where there are very few customers, typically at the end of a rural line, it may be more cost-effective to install a remote area power system to supply these customers, compared to replacing the line.

For our transmission towers, we would undertake economic and optioneering analysis, to determine best way to manage their associated risks. Depending on the specific drivers and risks for each line or tower, this may include, but not be limited to, painting versus replacing the tower, componentry replacement, reinforcing ground condition i.e. installing retaining around tower footings, and replacement of the footings. The forecast presented in this section assumes periodic componentry replacement or repair. Other options may be undertaken in the future on an ad hoc basis; however, we believe this is immaterial with respect to the overall forecast as we expect very few to occur.

Use of criticality in works planning and delivery

We prioritise pole replacements or defect repairs that could have a significant impact on public and worker safety and network performance. For concrete poles, this is done during an inspection or when the fault is found. We have prioritised inspection and replacement of wood poles using network disruption criticality.

Box 9.10: Improvement initiative – criticality framework

We are developing a criticality framework that categorises the consequence of failure if an asset fails. We are currently working on improving this framework further before it can be used for works planning and delivery. It considers proximity of the pole to schools, hospitals, and other high foot-traffic areas as a proxy for public safety criticality. Other dimensions such as reputational, environmental, and legal/regulatory impacts will also be considered.

Disposal

We dispose of poles when they are replaced. Softwood poles treated with chromated copper arsenate (CCA) need to be disposed of at an appropriate facility. We currently do not repurpose poles for any reason.

Box 9.11: Meeting our portfolio objectives – environmental and sustainability

Wooden poles and crossarms are disposed of responsibly

Coordination with other works

We replace pole-mounted equipment, such as distribution transformers, pole-mounted switchgear, and cast-iron potheads, together with poles when they are in poor condition. During conductor replacements, we may also replace poles that are either in poor condition or under the strength required to support the new conductors. This enables efficient delivery and minimises customer disruption. All poles replaced on conductor projects are covered under the overhead conductor portfolio forecasts.

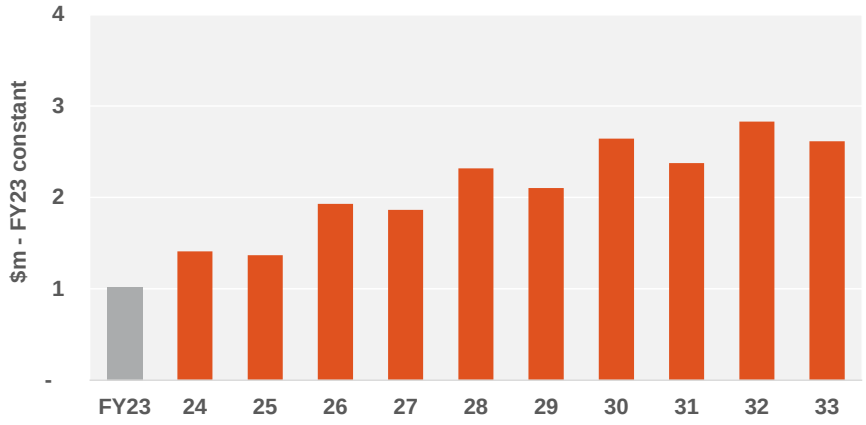
Box 9.12: Meeting our portfolio objectives – network performance

All surrounding and pole-mounted assets are assessed before planned pole replacements. Coordinating work allows us to reduce planned interruptions to customers.

Poles fleet expenditure forecast

We forecast renewal Capex for poles and towers of approximately $23.7 million in the planning period. Note this forecast excludes poles replaced with overhead conductors because of either condition or strength requirements. It does cover the expected average cost of replacing pole-mounted equipment with the pole.

Figure 9.14: Forecast poles and towers Capex

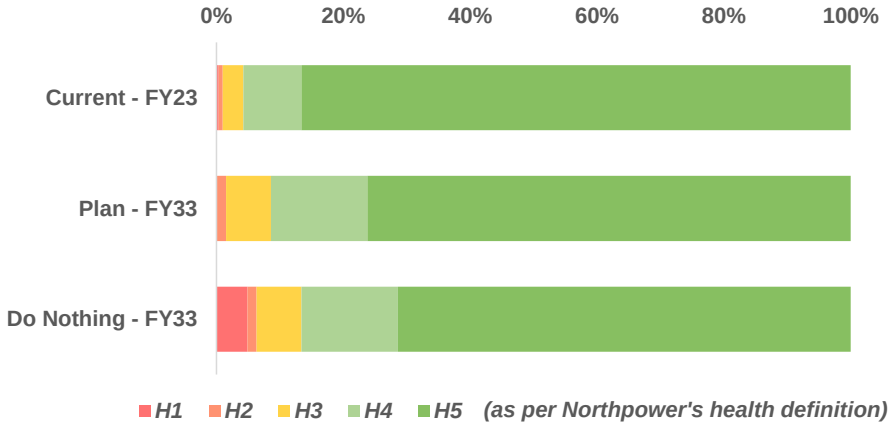


Our forecast aims to continue maintaining pole fleet health by replacing poles when they are in poor condition. This expenditure also includes an estimate of expected tower remediation. We expect this expenditure to gradually increase over time as the fleet population ages.

Benefits

The figure below compares our projected asset health in FY33 following our planned programme of renewals, with a counterfactual do-nothing scenario. This comparison illustrates the benefits of our proposed programme.

Figure 9.15: Projected poles asset health



This proposed work programme will prevent ~5% of the fleet from becoming H1s over the period, relative to a do nothing approach.

9.3.4. Crossarms

Crossarm fleet overview

Crossarms are used in conjunction with insulators to support overhead conductors. A typical crossarm assembly (commonly referred as 'crossarm') consists of the crossarm itself, insulators, binders, jumpers, steel braces, and bolts. Other equipment can be mounted on crossarms, such as fuses, ABS, reclosers, and distribution transformers.

Figure 9.16: Crossarm assembly with drop-down fuses (left) and double crossarm arrangement (right)

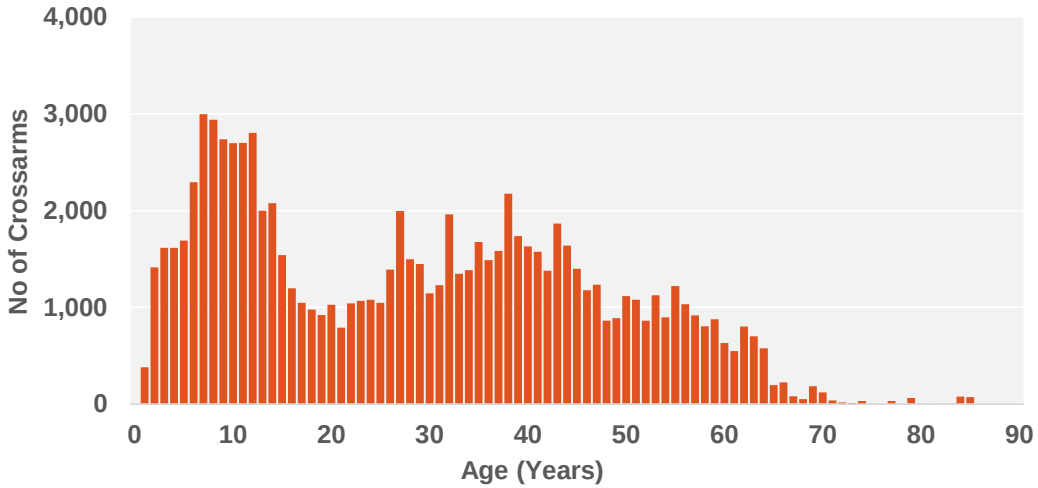
There are significant safety and performance risks associated with crossarm failure. Crossarms are always replaced when a pole is replaced. They are also replaced separately on an existing pole based on identified defects, even when the pole itself still has significant remaining life. We expect standalone replacement of crossarm assemblies to be a relatively large programme of work over the planning period.

Population and age

We have approximately 92,000 crossarms with an average of 1.7 crossarms per pole. Our crossarms are predominantly made from hardwood, with steel crossarms being used more recently. Wood crossarms have insulating characteristics that limit fault currents and can be easily drilled, allowing for simple installation of ancillary components. Steel crossarms are an alternative for high-strength requirements.

We are working on improving our data capture for crossarms to identify these separately as assets. Not all crossarm ages are recorded reliably, particularly older crossarms. Where this information is not known, we have assumed the crossarm is the same age as its pole. We believe this is a sound assumption as it is common to replace a crossarm at the same time as the pole. In the future we will capture crossarm age information more reliably.

Figure 9.17: Crossarms age profile



We also do not always record what type of crossarm we use presently. We know the majority of our crossarms will be wood as we have only recently installed steel crossarms on a limited basis. The life expectancy of wooden crossarms is 45 years.

Box 9.13: Meeting our portfolio objectives – network performance and safety

Our new asset management system and the input of accurate crossarm data will help improve our approach to crossarm renewal forecasting reducing the likelihood of failures.

Condition, performance, and risks

In-service failure of a crossarm can lead to dropped conductors or spans lowered to unsafe clearances, presenting a significant safety risk to the public and usually leading to outages. Wooden crossarms typically fail from age-related deterioration, causing loss of strength, or from fungal decay, usually starting on the upper side because of exposure to moisture and other contaminates. Wooden crossarms also fail because of burning caused by electrical tracking from insulation degradation. Failure modes and rates of decay are strongly influenced by environmental conditions. Crossarm components also fail – binders wear out over time and can loosen or break, allowing the conductor to swing free from the crossarm, usually resulting in an outage.

Condition

Due to the limitations in our data, we are unable to confirm the condition of our crossarm fleet accurately. Based on our assumptions, we suspect many crossarms may be beyond their expected life; however, this may also be due to the quality of our data. We are working on improving our crossarm data to have more certainty around our crossarm fleet condition.

We undertake a ground-based crossarm inspection programme as part of our overhead line inspections to identify defective crossarms. However, these inspections may not adequately identify defects or poor condition crossarms as wooden crossarms can decay, split, or weather from the top. We are currently assessing options to address this gap. This includes aerial-based inspections or supplementing ground-based inspections with pole top photography, thermal imaging, and acoustics.

Performance

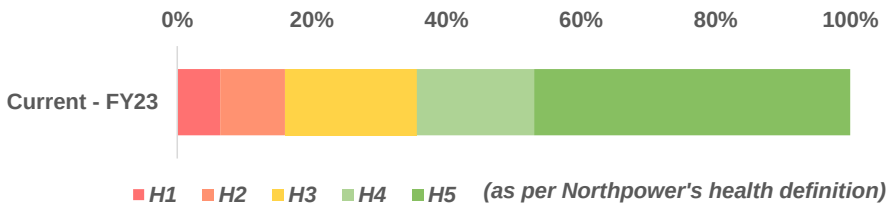
As discussed previously, we are working on improving our performance data to capture problem, cause, and remedy information at a more granular level. To date we have not had many crossarm failures, but this information will become more critical as the fleet ages.

Asset health

Our AHI for crossarms is based on expected remaining life where life expectancy is represented by a normal distribution with a mean of 45 years.

Current asset health of our crossarm fleet is shown below. It indicates ~6% of our crossarms are at end of life (H1), with a further ~30% due for replacement over the next 10 years (H2 and H3). This is primarily due to many crossarms exceeding their expected life.

Figure 9.18: Crossarms current asset health



Over the next few years we are working on improving our crossarm inspections and asset data to have more certainty around the fleet health and investment requirements.

Risks

Crossarms by their nature may pose safety risks. For example, a crossarm failure can result in a conductor falling which, in turn, could result in an electrocution or fire. This will usually cause a loss of supply (except for instances where we have N-1 security).

Table 9.14: Crossarm risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Insulator leakage leading to wood crossarm or pole fire Leakage current on (generally pin type) insulators tracking along the wooden crossarm or tracking down the interface to a wooden pole, starting a fire. This often leads to the conductors floating above ground (potentially live) or falling to ground	Inspection programmes, leading to replacement of visually defective crossarms	Safety
Intermittent fault caused by leaking pin insulators Often this is difficult to identify visually, particularly from the ground	Ground-based inspection assisted by acoustics	Network performance
Leaning insulator causing the conductor to detach, float, or fall to the ground.	Inspection programmes, leading to replacement of visually defective crossarms	Safety and network performance
Wooden crossarm breakage due to wood ageing/degradation, causing conductor down or conductor floating event	Inspection programmes, leading to replacement of visually defective crossarms	Safety and network performance
Binder failure causing conductor down or to float	Inspection programmes, leading to replacement of visually defective crossarms	Safety

Design and build

Our current fleet mainly comprises hardwood crossarms; however, we are exploring the use of steel crossarms and have installed a small number. We may consider the use of fibreglass crossarms in the future. We are monitoring developments in polymer insulators and considering their wider usage. Wood crossarms are still preferred due to their non-conductive properties, lower upfront cost, and ease of customisation.

We specify post type insulators rather than pin type to avoid hole elongation failure due to conductor vibration and potential failure of the cement pin interface. Considerations around contracting options and design arrangements are the same for crossarms as for poles; however, crossarm replacement tends to require significantly less, if any, design work.

Operate and maintain

Preventive maintenance

Crossarm and insulator replacements generally result from preventive maintenance inspections and are often replaced in conjunction with pole replacements for efficiency. Renewals are done in conjunction with other maintenance tasks on poles or conductors.

Table 9.15: Crossarms preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Helicopter inspection of crossarms on subtransmission circuits. This is a visual inspection which picks up defects such as cracks and decay	Yearly
Ground-based visual inspection of crossarms as part of overhead network inspections, which includes basic condition observations	Five yearly

Our inspections in the past have traditionally been ground based. However, wooden crossarms typically decay, split or weather from the top. We are investigating techniques that will enable us to pick up these types of defects. This will help identify and diagnose defects faster and more accurately compared to traditional ground-based inspections. Modern technology such as thermal imaging, acoustic/ultrasonic inspections, and pole-top photography (using drones or cameras mounted on fibreglass poles) are being considered.

Box 9.14: Innovation example – supplementing our inspections regime

The photo below depicts our state-of-the-art vehicle-mounted robotic thermal camera, paired with artificial intelligence (AI) to analyse and find defect patterns in the thermal data collected.

Corrective maintenance

Crossarm fault and defect repairs, identified by inspections or second fault responses, involve replacement of individual components. This typically includes:

- replacing broken or damaged arm braces and bolts
- replacing individual cracked or failed insulators
- repairing minor workmanship issues and defects, i.e. retightening on bolts, rust control on steel braces.

Any proactive work on crossarms that replaces the entire crossarm assembly, regardless of the defect, is considered Capex.

Reactive maintenance

Crossarm faults arising from first fault response involve similar activities as corrective maintenance, but they are unplanned. Occasionally, complete crossarm assembly replacement is needed to restore service.

Renew or dispose

Historically, we have taken a reactive approach to crossarm renewal. This was mainly driven by defects identified. We have also replaced crossarms with poor condition poles. Our concrete poles typically last longer than crossarms, meaning this approach does not address the long-term failure risks associated with crossarms. We are planning to proactively replace crossarms as a standalone programme of works.

Table 9.16: Summary of crossarms renewals approach

ASPECT	APPROACH USED
Renewal trigger	Condition
Forecasting approach	Repex modelling
Cost estimation	Volumetric

We renew crossarms primarily based on condition, and we replace crossarms together with poor condition poles. In the short term, we will prioritise replacing crossarms identified by existing inspections. Longer term, we expect to transition to a more thorough condition-based renewal approach.

Renewals forecasting

We use a Repex approach to forecast crossarm renewals. The Repex methodology applies a normal distribution in expected life across the fleet. Our crossarm expected life is 45 years, generally in alignment with others in the industry. Longer term, we intend to improve our forecasting methodology, to be either condition or survivor curve based once we have improved our asset data collection process and inspections.

Our unit rates are based on the expected average cost to replace a standalone crossarm assembly. Conductors, poles, and pole-mounted equipment replacements are excluded as they are covered under their respective forecasts.

Options analysis

Options analysis for crossarm replacements is generally limited to consider the most economical way to replace the crossarms, as opposed to ways to mitigate the crossarm failure risk. Generally, we replace the crossarm on the existing pole, if the existing pole has no issues or defects, or we replace the entire pole and crossarm assembly where both are in poor condition.

Use of criticality in works planning and delivery

Crossarm replacements and defects that could have a significant impact on safety and network reliability are our priority. This includes prioritising poor condition or failed crossarms that pose a significant public safety risk (i.e. conductors have dropped due to a broken crossarm), potential to damage properties (i.e. crossarm fire), and/or significant loss of supply to customers. This prioritisation is currently done during the inspection or when the fault is found and can be subjective. We are looking to implement a criticality framework and model that would assign criticality to each asset in a systematic and consistent manner.

Disposal

Crossarm assemblies have no specific disposal requirements unless CCA treated; therefore the same requirements as poles apply.

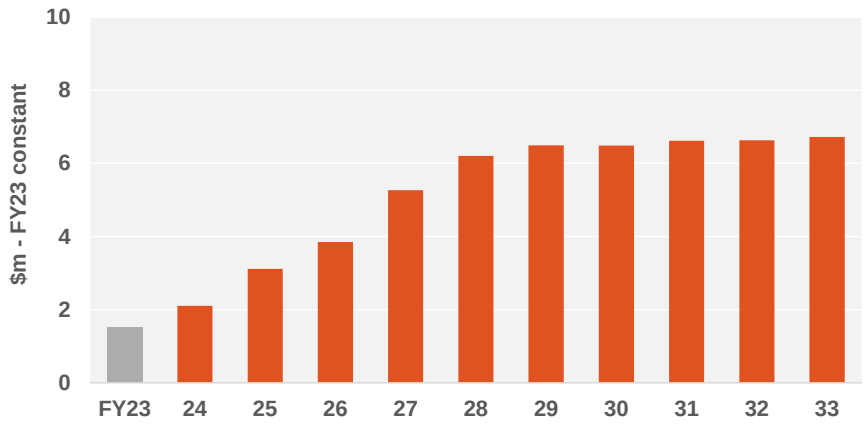
Coordination with other works

Like poles, crossarms are often replaced as part of overhead line reconstruction projects, such as conductor upgrades as part of network development works, or replaced together with poles. As a crossarm's expected life is short compared with a pole or conductor, its replacement for end-of-life reasons can often be coordinated with these works.

Crossarm fleet expenditure forecast

We forecast renewal Capex of approximately $58 million for standalone crossarm replacements during the next 10 years. This excludes crossarms replaced with poles or conductors, other pole-mounted assets, distribution transformers, and reclosers.

Figure 9.19: Forecast crossarms Capex



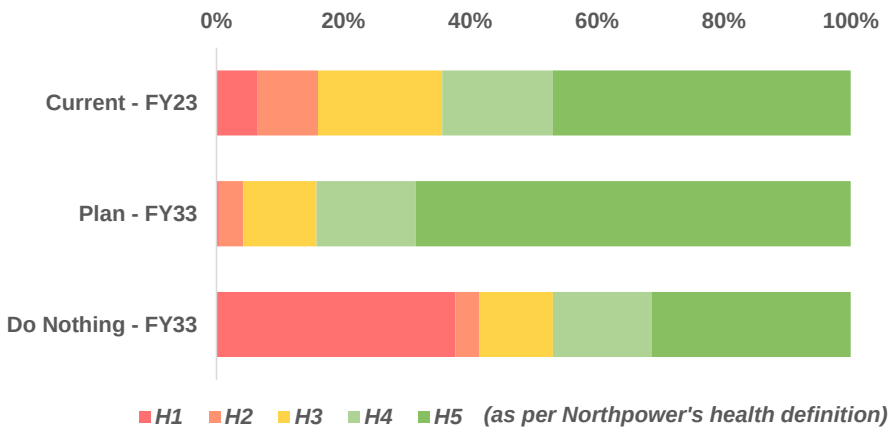
Our historical standalone crossarm replacement levels were low, as most replacements were bundled together with poles and conductors. We intend to increase our expenditure gradually over the planning period and slowly ramp up to a steady state. This allows us to gradually lift the amount of work we can deliver in line with our long-term requirements.

The forecast assumes the standalone replacement of crossarms. Note that crossarms replaced with poor condition poles are included in the poles forecast.

Benefits

The figure below shows our project asset health in FY33 following our planned programme of crossarm renewals and compares it with the current state and a hypothetical do nothing scenario. This indicates the benefits provided by our proposed investment programme.

Figure 9.20: Projected crossarms asset health



Currently approximately 6% of our crossarm fleet have exceeded their expected life. Our planned renewals programme is expected to reduce this to <1% by FY33, and we are expecting to maintain level beyond this planning period. In the hypothetical do nothing scenario, 38% of our fleet will be H1 and at risk of failure by FY33. This would create significant risk on our network.

9.4. Substation equipment

This section describes our substation equipment portfolio[36] which includes four asset fleets:

- Indoor switchgear
- Outdoor switchgear
- Substation power transformers
- Infrastructure and facilities.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches, and provides expenditure forecasts for the planning period.

Box 9.15: Portfolio summary

During the planning period, we expect to increase our investment in substation equipment to an average $4.4 million per year. However, expenditure varies from year to year, due to the timing and size of each substation project.

Our substation expenditure was relatively low before FY19. Since then, we have ramped up our expenditure, replacing equipment at our Hikurangi and Ngunguru zone substations. We plan to continue with this programme of works, driven by a need to:

- Replace poor condition assets, mainly replacing indoor switchgear, power transformers, and outdoor switchgear that have exceeded their expected life.
- Manage safety risks, particularly for our workers. This is associated with some of our indoor switchgear which have higher than acceptable arc flash risks. As such, we have prioritised replacement of oil-filled, non-arc, fault-contained switchgear.

Manage reliability risks, particularly where equipment failure can disrupt supply to many customers. We have many areas supplied by buses that are not fully sectionalised or require manual switching to restore supply. This prolongs outages more than necessary. As such, we are prioritising substation equipment replacements that have high reliability impacts.

Our substation equipment portfolio includes equipment located in our regional and zone substations. We have two regional substations at Kensington and Maungatapere which take supply from GXPs at 110kV and stepping this down to subtransmission voltages at 50kV/33kV. These two regional substations then supply zone substations throughout central Northland. Other zone substations take supply directly from GXPs at 33V, such as Bream Bay and Maungaturoto.

Our zone substations provide connection points between subtransmission circuits and stepping down voltages (through power transformers) to supply the distribution network at 11kV. Within our zone substations, we use indoor and outdoor switchgear to control, switch, and isolate the network as part of day-to-day operations. Our regional and zone substations are high-value critical assets, as they supply many thousands of customers. Asset failures usually require a prolonged outage to replace.

[36] All substation equipment Capex is covered under asset replacement and renewal information disclosure category, line items zone substations, are included in Schedule 11a in Appendix B.

Figure 9.21: Tikipunga zone substation outdoor switchyard

Some equipment will also be located within buildings, such as protection, SCADA, communication, and indoor switchgear. Most of our substation buildings also have air conditioning units, ventilation, and other facilities to support the equipment housed there.

Power transformers, bus work, and outdoor switchgear are located in a switchyard which typically contains engineered aggregate to minimise step and touch voltage hazards. We are in favour of using indoor switchgear and sometimes house the power transformer indoors, such as at our Maunu zone substation.

9.4.1. Substation equipment portfolio objectives

Our substation equipment portfolio objectives are listed in the table below.

Table 9.17: Substation equipment portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety	No fatalities and injuries associated with our zone substation equipment, including from arc flash hazards No fatalities or injuries to our workers or the public from step and touch potential hazards
Network performance	Manage failure risks through renewal and growth planning Comply with our latest security of supply standard when renewing zone substation assets
Supporting communities	Continue to develop and improve our asset health and risk modelling to support cost-effective decision-making
Environment and sustainability	No uncontained oil spills or significant SF_6 leaks Integrate the design of new zone substation assets with the neighbouring community to maintain or improve aesthetics Resolve any non-compliant noise pollution issues

9.4.2. Indoor switchgear

Indoor switchgear fleet overview

Indoor switchgear consists of switchgear panels that contain internal circuit breakers and instrumentation. They also include protection, control, and automation devices. Indoor switchgear can be employed in 11kV and 33kV applications. Indoor switchgear is compact and is typically housed in rooms/buildings.

Due to its location and being less susceptible to harsh environmental conditions, indoor switchgear often exceeds life expectancy. Circuit breakers form an integral part of the switchgear and are used to interrupt both normal and fault current protecting primary plant. Due to the close and confined space, the failure of indoor switchgear poses a high safety risk. All modern switchgear is suitably specified to withstand arc flash incidents, resulting in a significant lower safety risk. Older switchgear is oil filled and does not include arc fault protection. Our approach to indoor switchgear renewal takes this risk into account and includes an oil-filled switchgear replacement schedule.

Population and age

Our zone substation portfolio includes a total of 194 indoor circuit breakers (making up 28 switchboards). The table below summarises the population by type and rated voltage.

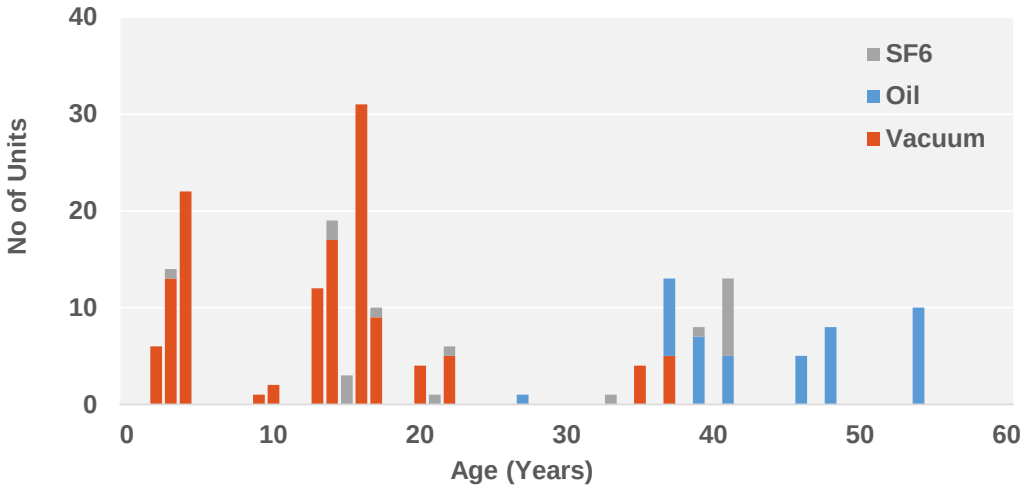
Table 9.18: Indoor switchgear circuit breaker population by rated voltage

INTERRUPTING MEDIUM	11kV	33kV	TOTAL
Vacuum	113	18	131
Oil	44	0	44
SF_6	0	19	19
Total	**157**	**37**	**194**

Indoor switchgear technology has changed over time. Before the 1990s, most switchgear used oil as the insulation and arc quenching medium. Our older indoor switchgear population is mostly oil-filled. Over the last 20 years, all indoor switchgear installed was vacuum or SF_6 based. They have a lower maintenance cost over their lifetime, as well as better switching characteristics.

The average age of our indoor switchgear is 22 years. Life expectancy for vacuum and SF_6 circuit breakers is 45 years, with our current fleet at 13 years and 28 years respectively. Our oil circuit breakers have an average age of 44 years, with the oldest being 54 years. These circuit breakers have a life expectancy of 50 years based on standard industry practice.

Figure 9.22: Indoor switchgear age profile



Condition, performance, and risks

Condition

We carry out routine preventive maintenance which includes gathering information on the condition of the switchgear. Insulation resistance tests provide a good indication of potential insulation breakdown. We analyse test results and trends of the same make across zone substations. This gives us a good indication of any potential issues.

During preventative maintenance testing, we have found two of our oil-filled circuit breakers of the resin cast type have had consistently high partial discharge test values. They have been monitored over the years and appear to be stable, with test values not worsening over time. Other types of circuit breakers, such as SF_6 and vacuum, appear to be in good condition considering their age profile.

Performance

In general, our indoor switchgear is reliable. We have experienced one significant failure event. This happened in 2021 while the transformer was being re-livened after routine maintenance. There was an explosion in a 33kV indoor switchboard and both 110kV circuits tripped. The flashover was found to be caused by the failure of a resin cast current transformer in the incomer panel supplied from the transformer. Following this event, we have been working on arc flash standards for zone substation and distribution assets. These standards will quantify potential arc flash hazards with existing assets and set out guidelines and operational requirements to mitigate these hazards.

Box 9.16: Meeting our portfolio objectives – safety

Ensuring operational procedures mitigate the risk of injury from arc flash hazard is prudent until the equipment is replaced or modified to meet modern IEC standards.

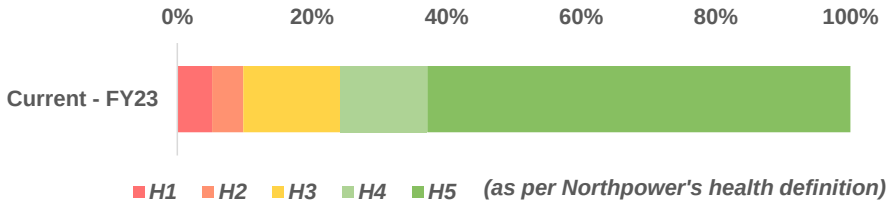
During preventive maintenance of our indoor switchgear, we discovered several circuit breakers exhibiting signs of deterioration. This included imbalances in breaker operating times, high carbon content in interrupter oil, and discrepancies in insulation resistance

values. These have been carefully examined against their age and similar models to confirm their operational efficiency.

Asset health

We consider the age of indoor switchgear to be a good proxy for asset health. We assign the AHI based on the remaining life of the asset when compared against the switchgear life expectancy. Life expectancy of the assets are varied in accordance with their field operating conditions. It is impacted by interrupter medium and the operating voltage ratio.\

Figure 9.23: Indoor switchgear current asset health



We expect to replace 24% of indoor switchgear over the next 10 years. Around 5% of the assets are H1 and will need replacement in the short term. Most of these replacements will be driven by our ageing oil circuit breakers.

Criticality

The key criticality dimensions are load serviced by the switchgear and operator safety. To prioritise the replacement of indoor switchgear, we have established a criticality index using a weighted average of the following factors:

- magnitude of the load supplied
- security levels of the operating zone substation
- fault rating capacity
- availability of spare parts
- arc flash criticality.

Replacement triggers have been identified by comparing the AHI values against the criticality index of the assets.

Risks

The potential of arc flash is a significant safety concern. Arc flash can cause property damage, significant injury, or even death. Furthermore, if such a malfunction occurs, it would have a major impact on network performance because the switchboard will most likely be inoperable and will require full replacement.

Our new switchgear is oil free and equipped to detect and contain or disperse an arc flash event. As a result, arc flash dangers are reduced in new switchgear. Arc flash analysis has been completed on our 11kV switchboards to establish their risk levels. We have defined a prudent level of arc flash energy to be no more than 8cal/cm². We use this, along with switchgear-specific factors, to categorise the risks of arc flash.

We use the following approaches to mitigate the risk of arc flash:

- PPE used by the working personnel near the switchboards should have appropriate arc flash rating
- arc flash ratings can be reduced by reconfiguration of the upstream network
- carrying out switching operations through remote SCADA with workers outside.

Other types of circuit breakers, such as oil circuit breakers, can increase the risk of fire; while SF_6 circuit breakers can leak. Substation buildings also need to be vermin-proof to prevent rodents damaging the power and communication cables. We have rodent traps installed at all our substations to mitigate this risk.

Design and build

Indoor switchgear is critical for the operation of our network. Our procurement, design, and installation process is rigorous enough to ensure the switchgear is fit for purpose. Vacuum and SF_6 circuit breakers no longer require frequent maintenance. The reliability of these units has significantly improved, which has considerably improved their whole-of-life cost.

We purchase indoor switchgear that has been arc flash tested in compliance with IEC 62271-200. In addition, when applicable, we are fitting our power transformers with neutral earthing resistors to lower phase-to-earth fault levels and the energy discharged during arc flash events to ground.

Operate and maintain

Preventive maintenance

Indoor switchgear undergoes routine inspections and maintenance to ensure its continued safe and reliable operation. Partial discharge detection is a dependable maintenance technique for detecting a range of insulation-related faults that might cause failures. Also, condition monitoring of SF_6, vacuum, and oil CBs are done on an as-needed basis.

Table 9.19: Indoor switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of switchgear, circuit breakers, voltage transformers, and associated control panels as part of zone substation equipment inspection	Two monthly
Acoustic emission and thermal imaging survey	Yearly
Partial discharge survey	Two yearly
Visual inspection of oil-filled 11kV switchgear condition, close/trip speed test, breaker service oil change, inspect and clean contact, electrical testing, and alarm check	Four yearly
Visual inspection of vacuum and SF_6 (5.5/11/33kV) switchgear condition, close/trip speed test, electrical testing, alarm check, check SF_6 pressure, measure wear gap	Four yearly
SF_6 moisture analysis	Eight yearly

Corrective maintenance

Indoor switchgear defects that were identified during inspections and maintenance are normally rectified under corrective maintenance. Normally SF_6 and vacuum circuit breakers

are sealed for life and they seldom require any maintenance. In the event of a drop in pressure or leakage, maintenance is done by trained personnel. Oil-filled circuit breakers can leak oil; this is addressed through corrective maintenance.

Reactive maintenance

Reactive maintenance of indoor switchgear is response to maloperation alerts or alarms received in the control centre. In all cases, an on-site assessment is required, with potential follow-up action based on the results.

Spares

Although switchboards are engineered to be highly reliable, they contain components that are crucial to their long-term operation. We have very limited spares available for older indoor switchgear. For the mid-life and new indoor switchgear, we carry spares so we can improve their repair times. When switchgear is retired, certain spare components may be held if they can be used for other assets still in service.

Renew or dispose

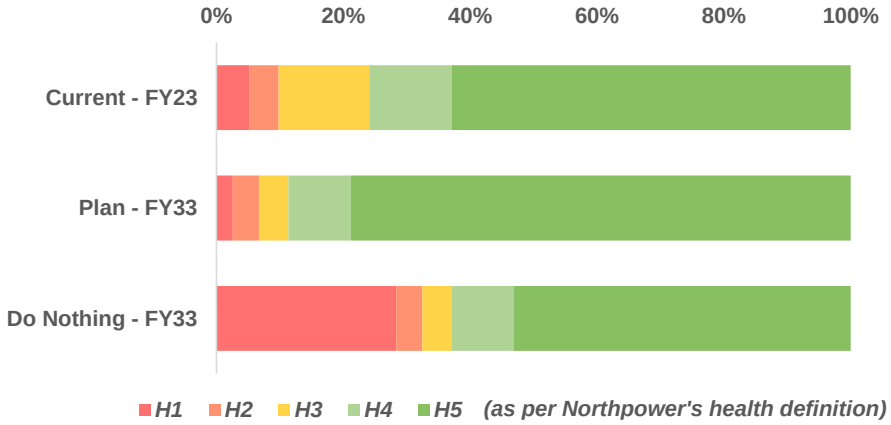
We plan our indoor switchgear renewal decisions based on the following factors: condition of the switchgear, known type and reliability issues, arc flash risks, fault levels, and spares availability. We examine all these aspects, as well as the criticality of the zone substation, to decide the best time for replacement.

We have a programme to replace old indoor switchboards equipped with oil-insulated 11kV circuit breakers with modern gas insulated vacuum circuit breakers. Seven 11kV switchboards are scheduled to be replaced over the next 10 years. In addition, there are two 33kV indoor switchboards which are planned for replacement.

Renewals forecasting

We have created an asset health versus criticality risk matrix approach to forecast indoor switchgear renewals. The model allows us to forecast changes in asset health and asset risk over time. The figure below summarises AHI for our indoor switchboard fleet.

Figure 9.24: Projected indoor switchgear asset health



Our indoor switchgear fleet is getting older, and the chance of failure is growing. Asset health reflects this, with around 25% of our fleet requiring replacement during the period.

Our planned fleet renewals programme will improve overall fleet health, decreasing H1s to around 2%. However, in the absence of any indoor switchgear renewals, asset health would deteriorate, creating a substantially greater level of H1s by the end of FY33.

Table 9.20: Summary of indoor switchgear renewals approach

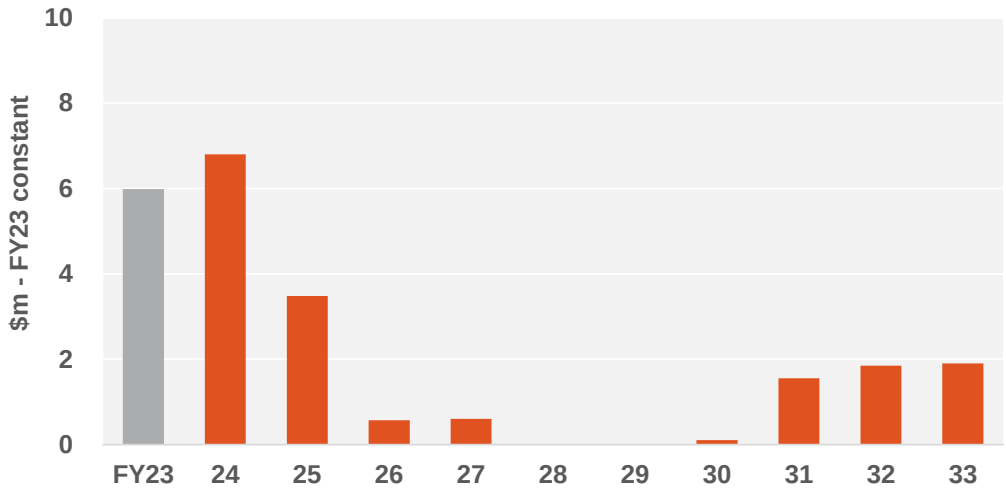
ASPECT	APPROACH USED
Renewal trigger	Ongoing programme replacing aged oil-filled circuit breakers with modern vacuum breakers over the next 10 years.

Disposal

We dispose of any indoor switchgear that have reached end of life, as it is removed from service. As we face difficulty in sourcing spares for older makes of indoor switchgear, we assess if the same make/model switchboard is still in service at another location and consider retaining removed components as spares. We take great care while disposing of environmentally sensitive SF_6 circuit breakers; this work is handled by specialist contractors who appropriately dispose of them. Other parts of the indoor switchgear like oil, copper, aluminium, and steel are recycled.

Indoor switchgear expenditure forecast

Figure 9.25: Forecast indoor switchgear capex



Benefits

There are many benefits of our planned indoor switchgear renewal programme:

- Less safety risk, due to aged, oil-filled, or non-arc fault contained switchgear
- Improved safety and network performance from reliable operation during faults
- Enhanced safety in design with modern indoor switchgear
- Enhanced network resilience through reduced downtime and fast arc flash protection clearance, preventing major equipment damage.

9.4.3. Outdoor switchgear

Outdoor switchgear fleet overview

Outdoor circuit breakers, air-break switches, load break switches, and fuses are the asset categories connected with HV outdoor switchyards in the outdoor switchgear fleet. Outdoor switchgear, like indoor switchgear, is primarily used to regulate, protect, and isolate electrical circuits. It de-energises equipment and offers isolation points to allow access to equipment for maintenance or repairs.

Outdoor switchgear provides considerable flexibility for equipment replacement; however, it requires significantly more space than indoor. Where there are space constraints, we consider conversion of outdoor switchgear into indoor switchgear.

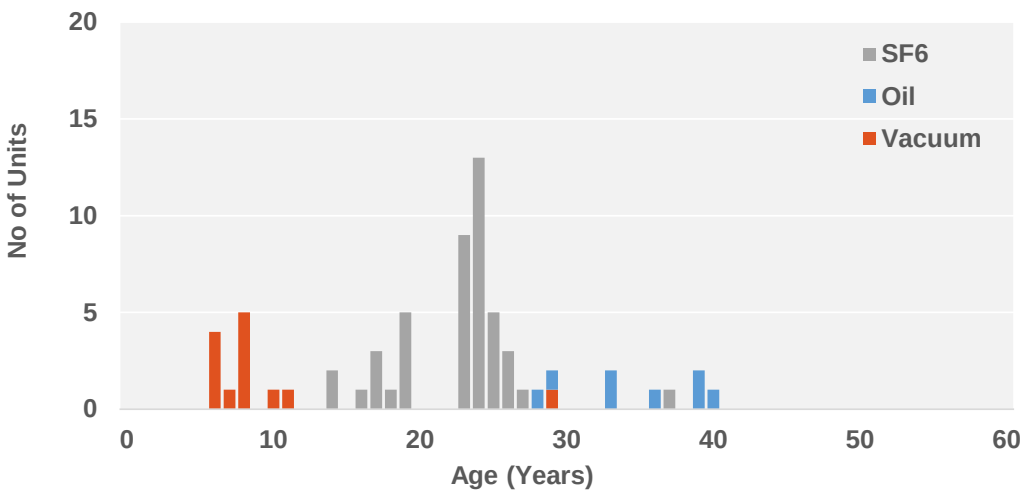
Population and age

The table below summarises our population of outdoor switchgear by type.

Table 9.21: Outdoor switchgear population by rated voltage

ASSET	INTERRUPTING MEDIUM	33KV	50KV	TOTAL
Outdoor circuit breakers	Vacuum	13	0	**13**
	Oil	8	0	**8**
	SF_6	38	6	**44**
Outdoor disconnectors & isolators		206	13	**219**
Total		**265**	**19**	**284**

Figure 9.26: Outdoor circuit breakers age profile[37]



The average age of our outdoor circuit breakers is 21 years, with vacuum and SF_6 at nine years and 23 years respectively. Our oil circuit breakers have an average age of 35 years and are in the process of being phased out.

[37] Note this age profile excludes outdoor disconnectors and isolators.

Condition, performance, and risks

Condition

Our oil circuit breaker fleet is obsolete as, in comparison to other types, oil-filled circuit breakers require more intensive maintenance and present a greater risk when switched, particularly when clearing faults. Spare parts are also difficult to obtain. We have developed a system for maintaining critical spares from retired circuit breakers and are in the process of retiring the remainder of the oil circuit breakers from our network.

Our SF_6 circuit breaker fleet is in generally good condition. We have had a small number of leaking SF_6 circuit breakers, and we are addressing these defects. The condition of the other outdoor switchgear assets on our network is generally satisfactory.

Performance

The performance of the outdoor switchgear fleet has been good, with no recent failures. Our older SF_6 circuit breaker models have presented challenges relating to gas leaks recently and we are working through these.

Criticality

In general, our outdoor switchgear has a high criticality because it is the main supply switchgear in our regional and zone substations. Outdoor switchgear replacements are mainly prioritised based on condition. The criticality framework under development will allow us to incorporate more criticality analysis into our outdoor switchgear replacement planning.

Risks

The table below summarises the major risks identified with our outdoor switchgear fleet.

Table 9.22: Outdoor switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
SF_6 gas leaks	Regular check of pressure gauge Fix leaks wherever possible	Environmental
Lightning strike	Regular inspection of surge arrestors Overhead earth wires	Reliability Safety
Seismic event	Structural modifications	Reliability
Failure to trip in fault conditions	Coordination of protection systems	Reliability
Pests inside substation	Proper fencing Pest detection sensors	Reliability
Arcing fault – leading to explosion	Regular maintenance	Safety

Design and build

Our outdoor switchgear fleet has not yet been standardised with a particular type or make. To reduce emissions, we aim to use equipment that does not contain SF_6, where economic. New outdoor switchyards are designed in accordance with best industry standard safety and access clearances. Wherever practical, to minimise downtime, replacements are planned to align with other replacements in the substation (such as power transformers).

Box 9.17: Meeting our portfolio objectives – environment and sustainability

By reducing the SF_6 in our fleet we lower the probability of leaking this greenhouse gas to the atmosphere. These alternative options are employed wherever they are economic.

Operate and maintain

Preventive maintenance

Preventive maintenance inspections on substation bus systems and structures highlight deterioration and issues requiring remedial action. Visual examination, thermal imaging, acoustic inspection, and partial discharge testing are used to identify components that need to be maintained and/or replaced. Our preventive maintenance routine is outlined below.

Table 9.23: Outdoor switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of switchgear, circuit breakers, voltage transformers and associated control panels as part of zone substation equipment inspection	Two monthly
Acoustic emission and thermal imaging survey	Yearly
Partial discharge survey	Two yearly
Visual inspection of Oil-filled 33kV switchgear condition, Kelman test, breaker service oil change, inspect and clean contact, electrical testing, and alarm check	Four yearly
Visual inspection of vacuum and SF_6 33kV switchgear condition, electrical testing, alarm check, SF_6 pressure, measure wear gap	Four yearly
SF_6 moisture analysis	Eight yearly

Corrective maintenance

Defects observed during preventive maintenance or visual inspections are addressed through corrective maintenance. Common defects are corrosion, gas or oil leaks, and loose bolts, etc. Outdoor switchgear is exposed to weather conditions, so it generally requires more preventative and corrective maintenance than indoor switchgear.

Reactive maintenance

When there is an alarm from SCADA or a maloperation or failure, we send technicians on-site for inspections and corrective actions. One of the major hurdles faced in reactive maintenance of older outdoor switchgear is the lack of spare parts and technical expertise.

Spares

We keep strategic spares to maintain our outdoor switchgear fleet. We also hold some older stock where spares are difficult to source. When switchgear is decommissioned, we determine if the unit is required as a whole or whether components can be re-used.

Renew or dispose

Our strategy is to replace circuit breakers and other outdoor switchgear equipment based on condition. We strive to avoid equipment failure as network performance and safety consequences can be severe.

Table 9.24: Summary of outdoor switchgear renewals approach

ASPECT	APPROACH USED
Outdoor switchgear	Proactive condition-based replacement.

Renewals forecasting

We individually plan (and forecast) outdoor switchgear replacements based on age and condition (visual and measured), while taking into account factors such as obsolescence and type issues.

Projects are individually costed based on desktop analysis of the scope required to replace the switchgear.

Options analysis

Options analysis is carried out for each outdoor switchgear replacement. We generally consider two options for outdoor switchgear replacements:

- Where there is sufficient room and clearances, we usually adopt a like-for-like replacement.
- Where there are clearance issues and space constraints (including consideration of future expansion requirements) we consider outdoor to indoor conversions.

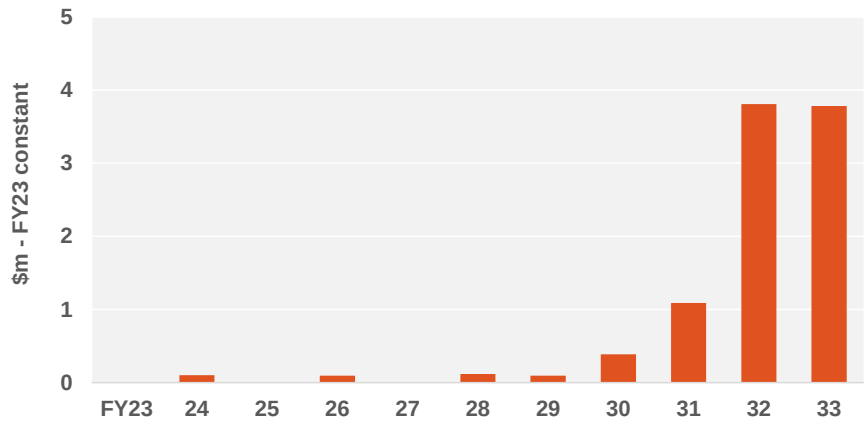
Both options are analysed and the option with the lowest whole-of-life cost that meets the required need is generally chosen.

Disposal

When outdoor switchgear reaches the end of its service life and is removed from service, we dispose of it. We review the retention of spare parts for any switchgear that is currently operating at another location. Oil and SF_6 are carefully disposed without causing significant environmental impacts, while other switchgear components like copper, aluminium, and steel, are recycled.

Outdoor switchgear expenditure forecast

Figure 9.27: Forecast outdoor switchgear Capex



Benefits

There are numerous benefits of our planned outdoor switchgear renewal programme:

- less safety risk as we will have less aged, oil-filled switchgear in the fleet
- improved safety and network performance from reliable operation during faults
- improved maintainability and worker safety due to better clearances around equipment.

9.4.4. Substation power transformers

Substation power transformers fleet overview

Power transformers installed at the zone substations are used to transform power from one voltage level to another. Most of our power transformers operate at 33/11kV but there are some operating at 50/11kV and 110/33 kV. Capacities range from 3.75 to 50MVA, and we will soon install two 100MVA at Kensington and Maungatapere. The power transformers are equipped with on load tap changers which are designed to maintain the distribution supply voltage, irrespective of the load changes on the grid. To mitigate risks from oil leaks and fire in case of faults, modern power transformers incorporate fire walls and oil bunds.

The main components of a power transformer are the core and windings, housing (or tank), bushings, cable boxes, insulating oil conservation and management systems, breather, cooling systems, and tap-changing mechanisms. They are typically reliable. Condition assessment is determined by regular routine testing and inspections. Transformers are typically expensive and have long lead times; therefore, robust planning processes to avoid failure are required, especially for cases where there is only N security.

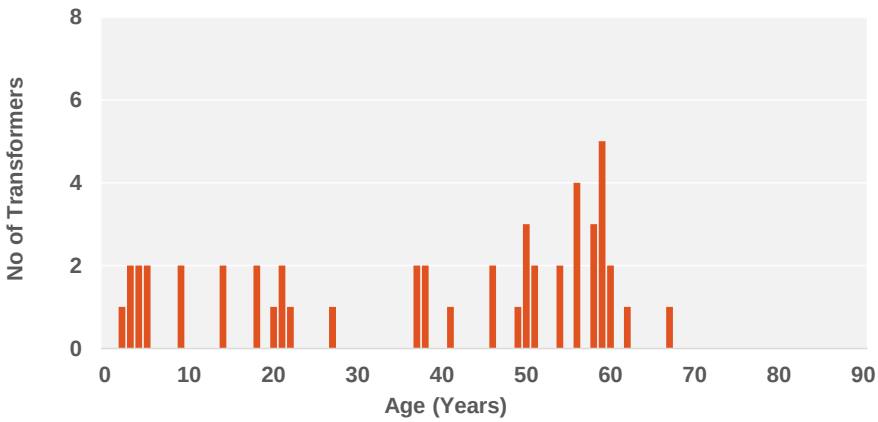
Population and age

The table below summarises the power transformer population by its operating voltage and size. We now buy standard sizes and vector configuration across the network to increase operational flexibility. Our substation power transformers are on average 38 years old, which is lower than the industry expected life standard of 60 years. We have two power transformers that are more than 60 years old, and 10 more are scheduled to reach that age in the next five years.

Table 9.25: Substation power transformers population by size

HIGHEST OPERATING VOLTAGE	SIZE (MVA)	POPULATION
11kV	<10	2
33kV	<10	13
	10-20	18
50kV	10-20	2
110kV	10-30	12
	>30	2
Total		**49**

Figure 9.28: Substation power transformers age profile



Our network has 49 operational power transformers across 22 zone substations and two spare transformers to ensure that we have operational flexibility in case of a failure. All except the 110/33 kV transformers at our two regional substations have on load tap changers.

Condition, performance, and risks

Condition

Our power transformer fleet is in generally good condition and displays no evidence of substantial internal deterioration, overheating, or arcing. They are regularly tested and inspected. This helps us understand their ageing and to identify defects.

Performance

Power transformer failures are uncommon, but they can have serious consequences. A failure may lead to a long downtime, depending on its severity. Power transformer failures can result in loss of supply or reduced security of supply, depending on the security level of the zone substation. On load tap changer failures are often caused by wear and tear of the moving contacts, while large failures are mostly caused by manufacturing flaws in the core and windings.

In our substations during the past 15 years, there have been three significant power transformer failures that required complete replacement of the transformer.

- Mareretu (failed in 2017; age 52 at time of failure): A winding fault occurred within the transformer. It was uneconomic to repair since there were no winding facilities in the country for that size of transformer.
- Kensington (failed in 2015, age 57 at time of failure): A winding fault occurred within the transformer because of water drizzling from the conservator. It was uneconomic to repair considering its age and the fact there were no suitable winding facilities in the country.
- Kaiwaka (failed in 2015, age 55 at time of failure): There was a problem with the on load tap changer that led to the box deforming. This needed a full restoration. However, given the remaining life of the transformer and the necessity for parts to be fabricated abroad, it was decided that repair was not cost-effective.

The age of the power transformers that failed prematurely supports the base life expectancy of 60 years. During analysis of the common faults occurring in transformers, it has been observed that a frequent contributor to the faults is on load tap changers, and in most of the cases this occurs due to the defective contacts. When problems arise, these are fixed as part of corrective maintenance.

Asset health

Our routine testing and inspection of power transformers helps us understand the extent of degradation and allows for the early detection of any possible internal faults. The fleet's exterior condition, particularly the degree of corrosion and oil leaks, is in accordance with expectations based on age and location. We have used the EEA's AHI guide (2019) to assess power transformer health by determining scores for end-of-life drivers such as paper degree of polymerisation, bushing condition, tank external condition, and insulation system condition. We apply weightings to establish an overall health assessment.

Based on the AHI scores of our 42 transformers, six of them are in H1 or H2 and are programmed for replacement over the next 10 years.

Criticality

Power transformers generally have a high criticality and are therefore a priority for replacement based on condition. The criticality framework we are developing will enable us to incorporate more criticality analysis into our power transformer replacement planning.

Risks

The major risks found in our power transformer fleet are summarised in the table below.

Table 9.26: Power transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Oil spill	Bunding and oil containment are features of new transformers to contain oil spills Routine inspections to look for low oil levels, oil leaks, and corrosion that can lead to leaks Corrective maintenance remediation	Environment and sustainability.
Fire caused by a faulty transformer	Replacements and new transformer installations are carried out to meet clearance standards, or firewalls are installed	Safety
Seismic event	New transformers are designed to be seismically compliant	Network performance Safety
Transformer noise	Remedial measures are undertaken in case of excessive noise	Environment and sustainability
Failures in on load tap changer and transformer internals	Oil testing of on load tap changer Preventive maintenance of on load tap changers Strategic spares Maintaining N-1 security levels for larger loads	Network performance
Lightning strike or switching surge	Surge arrestors on both LV and HV side of the transformer	Network performance

Design and build

We have procurement controls in place to ensure we install high-quality and reliable power transformers. By working with a limited number of manufacturers and using uniform standards and design, our procurement processes have become more effective. Quality control measures are employed throughout procurement, installation, and commissioning.

New power transformer installations are equipped with suitable oil containment facilities and, where required, suitably designed firewalls. These are constructed to meet local seismic requirements. Before the installation of any power transformer, where there may be potential noise implications, we conduct acoustic studies and install appropriate controls to ensure we comply with council noise rules.

Box 9.18: Meeting our portfolio objectives – environment and sustainability

We ensure non-compliant noise pollution issues are quickly resolved. We consult with local councils and communities on aesthetic requirements for new asset installations.

Operate and maintain

Preventive maintenance

Power transformers and their components, such as tap changers, undergo preventive maintenance to ensure their continued safe and reliable operation. Preventive maintenance activities for our power transformer fleet are summarised in the below table.

Table 9.27: Substation power transformers preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of transformers as part of zone substation equipment inspection: including inspecting oil levels/leaks, breather fault, Buchholz, winding/oil temperature, fans, tap changer, silica gel	Two monthly
Acoustic emission and thermal imaging survey	Yearly
Dissolved gas analysis to identify the presence of internal faults	Yearly
Partial discharge survey	Yearly
Polarisation depolarisation current testing	Two yearly
Tap changer service as part of transformer service and structure inspection	Four yearly
Visual inspection, insulation resistance, oil temperature gauge checks, Buchholz and pressure relief operational test, neutral earth resistor test.	Four yearly

Corrective maintenance

Corrective maintenance activities on power transformers include corrosion treatment, silica gel replacements, and repair of faulty components. Where oil is found to be out of specification it is filtered or replaced. For transformers that are near to the coast, we usually paint and repair rust as part of their mid-life refurbishment.

Minor defects discovered during visual inspections, such as corrosion, oil leaks, loose connections, faulty earthing, are repaired on site. Major defects identified during inspections, such as internal flaws in the core, winding, and tap changers, may require specialist resources and take longer to resolve.

Reactive maintenance

We carry out reactive maintenance on power transformers in response to minor and major faults. Alarms from sensors contribute to minor faults and may require an outage to repair. Major faults may be caused by issues in windings or the tap changer, which have caused the transformer mechanical protection to trip. These faults usually lead to prolonged outage and repair times.

Spares

We have a 33/11kV 5MVA transformer and a 110/19.1kV 16MVA single phase transformer as spares. These can be put into service if there is a major fault. We also keep some spare sensors and other major components in stock. When transformers are retired, if some parts can be used with other units on the network, they are often kept as spares.

We are looking to procure a spare for the planned Kensington and Maungatapere 100MVA transformers. This will help to main security of supply for our regional substations.

Renew or dispose

We plan for the renewal of our power transformers based on condition. This is assessed using a combination of age, measured and observed condition, type issues, and maintenance costs. Power transformer replacements are grouped with other renewal needs at the zone substation and are delivered as single projects.

Renewals forecasting

Power transformers are individually scheduled for renewal based on condition. We carry out a desktop assessment to determine the approximate scope and cost of the replacement project for forecasting purposes.

We are developing a transformer risk model to forecast power transformer replacements based on risk. We are improving and refining our asset health and criticality models to enable improved risk-based decisions.

Options analysis

When a transformer is identified to be in a poor condition, options for replacement, refurbishment, component replacement, or decommissioning/network reconfiguration are typically considered. The preferred option is selected based on the lowest whole-of-life cost.

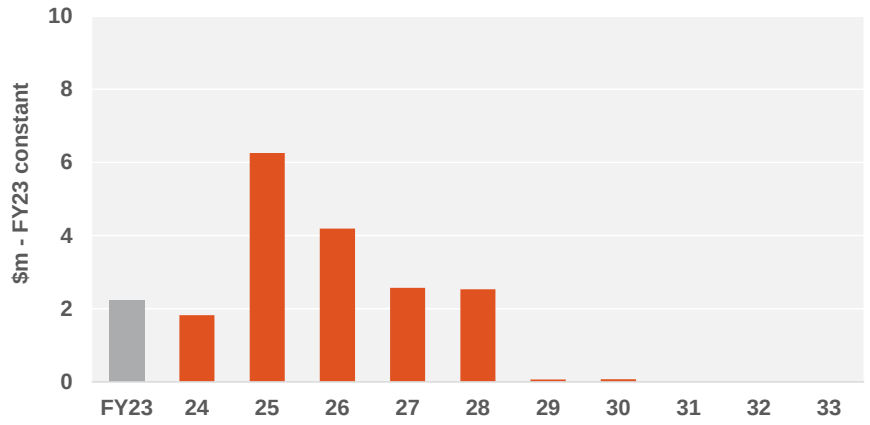
As part of our power transformer renewal programme, we will upgrade oil containment and separation systems, install transformer firewalls, and review and upgrade transformer foundations to ensure appropriate seismic standards are met.

Disposal

When power transformers cannot be redeployed and can no longer be used as a spare, we dispose of them. Oil is disposed of through an approved handler and the transformer's copper and steel are recycled.

Power transformer expenditure forecast

Figure 9.29: Forecast substation power transformers Capex



Benefits

The benefits of our power transformer renewal programme are:

- decreased disruption risk by removing higher failure-risk transformers
- mitigation of environmental risk by installing modern oil containment.

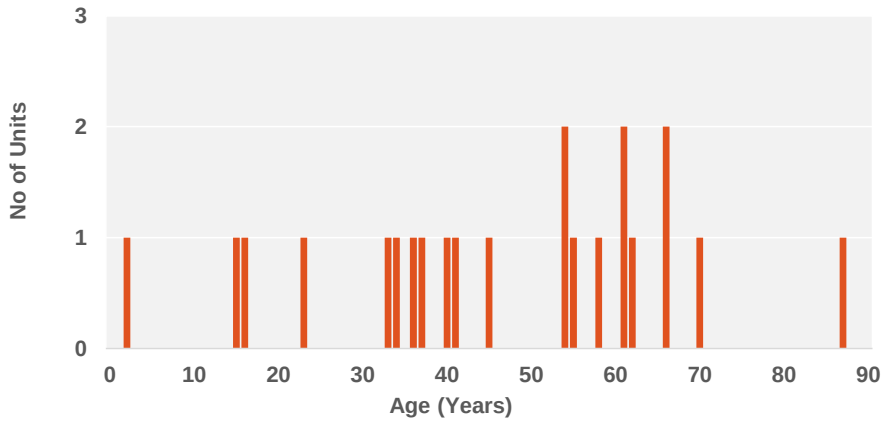
9.4.5. Infrastructure and facilities

Infrastructure and facilities overview

We have 22 regional and zone substation sites, with 21 buildings housing equipment. Preventive maintenance inspections on substation buildings and grounds highlight potential deterioration issues requiring remedial action. The main driver for inspections is safety, and specific attention is given to site security and safety signage. Security and access control has been implemented at the main office and at several substations. We plan to roll out this system across all zone substations over the next few years.

Population and age profile

Figure 9.30: Building age profile



Condition

Our buildings are in satisfactory, functional, and safe condition. Buildings are either retained indefinitely or until no longer required. Our oldest building is 87-years old (Mareretu).

Operate and maintain

Buildings play a vital role in the overall protection of indoor equipment from environmental elements, third-party access, and being structurally sound. To ensure overall integrity, defects are identified through routine inspection.

Preventive maintenance

Table 9.28: Buildings and grounds preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Check operation, clean filters, and service air-conditioning as part of zone substation equipment inspection	Two monthly
Zone substation grounds maintenance including lawn mowing, garden and weed management	Monthly
Building, fittings, and fencing inspection for damage, weather-tightness, and security	Two monthly
Zone substation smoke detector testing	Six monthly
Visual inspection of oil bunding as part of zone substation equipment inspection	Two monthly
Test substation security alarms as part of zone substation equipment inspection	Two monthly

Corrective maintenance

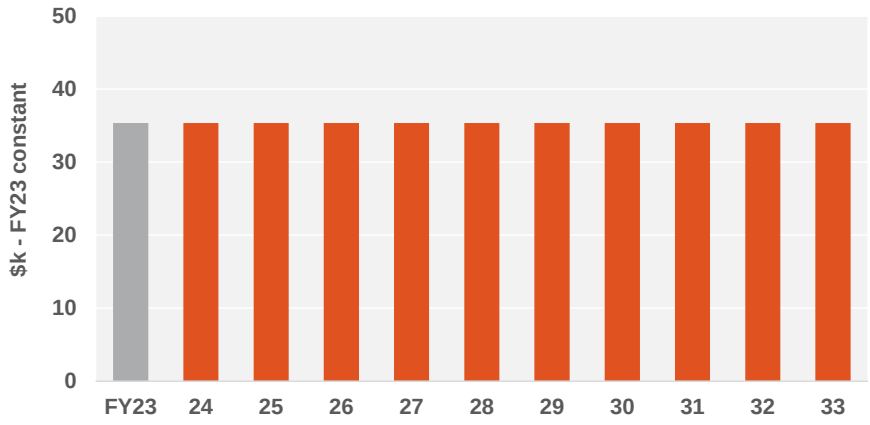
Water ingress into substation buildings can damage indoor equipment. Wooden doors and frames could be a source of water ingress. Where detected they are replaced with aluminium doors and/or frames. Much of our substation facilities are constructed from metal, including fences and gates, and these deteriorate over time. When rust is detected, it is treated at an early stage to prevent long-term damage and expedited replacement.

Reactive maintenance

Reactive maintenance on buildings and facilities is typically performed to repair issues including vandalism and graffiti, especially where security of our facilities is compromised.

Infrastructure and facilities expenditure forecast

Figure 9.31: Forecast infrastructure and facilities Capex



Benefits

The benefits of our infrastructure and facilities renewal programme are:

- maintaining our buildings and grounds fleet in good condition
- continue to provide safe and secure housing for secondary systems and auxiliary systems.

9.5. Underground cables

This section describes our underground cable portfolio and summarises our associated fleet management plan. The portfolio includes:

- subtransmission cables
- distribution and LV cables.

This section gives an overview of the assets, including their population, age, and condition. It outlines our renewals strategy and forecasts for the 10-year period.

Box 9.19: Portfolio summary

We proactively replace subtransmission cable sections based on age (compared to expected life) and condition. Distribution and LV cable renewals are mainly reactive, undertaken based on condition or when they fail. We are also proactively replacing cast-iron potheads in the planning period.

We forecast subtransmission cables on an identified/individual basis, coordinating replacements and upgrades with growth requirements. We forecast distribution and LV cables using the Repex methodology. We plan to spend an average of $0.9 million per year on cable renewals.

Our cable renewals focus on maintaining reliability and addressing environmental concerns. The reliability impacts of cable faults, particularly subtransmission cable faults, can be greater than for overhead conductors because of the longer repair and fault-finding times. These repairs often require specialist resources.

9.5.1. Underground cables portfolio objectives

Our portfolio objectives for the underground cables portfolio are listed below.

Table 9.29: Underground cables portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety	No fatalities and injuries from cable and termination failures Reduce third-party caused failures by increasing public awareness of safety risks associated with cable strikes
Network performance	Maintain underground cable failures at current levels Review meshed subtransmission network for opportunities to simplify and strengthen network resilience around the Whangārei area
Supporting communities	Consider options for improving network resilience, taking into account the whole-of-life costs for each option
Environment and sustainability	Minimise oil leakage from our oil-filled subtransmission cables Manage obsolescence risk with our oil-filled subtransmission cables

9.5.2. Subtransmission cables

Subtransmission cables fleet overview

Our subtransmission cables connect supply points at GXPs to our zone substations. They also link our zone substations for load transfer and maintaining security levels. Based on the power these cables carry, they are a critical network component and are managed as

a separate fleet. The nature of the subtransmission network is that the cables are point-to-point, unlike distribution cables which generally have multiple tee-off points.

Our subtransmission cable fleet consists of ~24km of cable. It includes ancillary equipment such as surge arrestors, various joints, and gas and oil pressurisation equipment.

Aluminium cross-linked polyethylene (XLPE) is the standard cable type used on our underground subtransmission network. Oil-filled and paper insulated lead covered (PILC) cables that were installed in the 1960s to 1980s are still in service but have become obsolete due to the unavailability of spare parts.

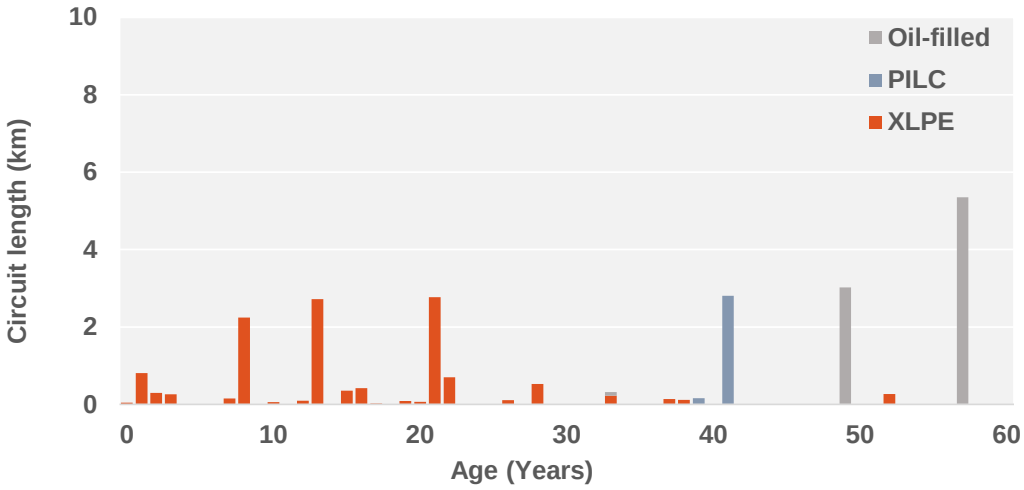
Population and age

Our subtransmission cable network consists of XLPE cables, PILC cables, and oil-filled paper insulated (oil-filled) cables. The table below summarises their population by type. XLPE cables make up more than 50% of total cable circuit length.

Table 9.30: Subtransmission cable population by type

CABLE TYPE	CIRCUIT LENGTH (KM)	PERCENTAGE
XLPE	12.4	52%
PILC	3.0	12%
Oil-filled	8.5	36%
Total	**23.9**	**100%**

Figure 9.32: Subtransmission cable age profile



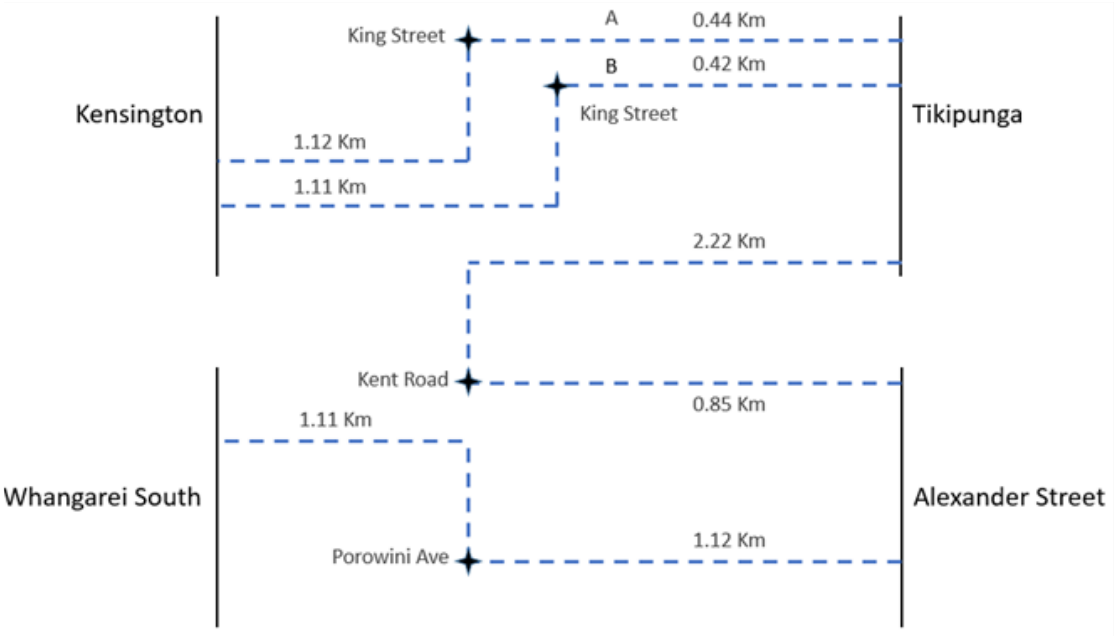
PILC cables are manufactured using layers of paper impregnated with a compound mineral oil as insulating medium, both as individual core and overall insulation. The cable is encased in an extruded lead sheath and wrapped in an outer sheath of either tar impregnated fibre material, PVC, or polyethylene. PILC has been used internationally for more than 100 years and manufactured in New Zealand since the early 1950s. PILC cables have a good performance record. The major hurdle we face in maintaining these cables is the shortage of skilled staff who have experience with them.

The oldest XLPE cable on the network was installed in 1984, and we have not experienced any defects caused by water treeing in this fleet. This cable has a life expectancy of 60 years, so this is a relatively young fleet. XLPE cable comes with copper or aluminium conductor. Aluminium is more cost-effective and therefore more widely used today.

Oil-filled cable is used to increase the voltage withstand capacity of the paper insulation. Using the oil as an insulation medium allows for less paper insulation to be used, resulting in a smaller, cheaper cable. These oil-filled cables do require many ancillary components to continually monitor the oil pressure and do the top-ups to maintain the designed oil pressure. Most of the oil-filled cables were installed during the 1960s. As these oil-filled cables have a life of just over 70 years of age, the entire population will likely need replacement within the next 10 years.

We have four oil-filled subtransmission cable circuits located predominantly around the Whangārei area operating at a voltage level of 33kV. They help form a meshed network, providing redundancy for the connected zone substations as shown below.

Figure 9.33: Overview of oil subtransmission cable network in Whangārei



The table below indicates cable names, age, and length of each section.

Table 9.31: Subtransmission oil-filled cable asset age and length

CABLE DESIGNATION	AGE	LENGTH (KM)
Whangārei South to Alexander Street	56	2.2
Alexander Street to Tikipunga	56	3.1
Kensington to Tikipunga A	48	1.6
Kensington to Tikipunga B	48	1.5

Of these four, the two cables between Tikipunga to Kensington operate at N-1 security level. The other cables operate at N security which means there is no backup in case of an outage.

Condition, performance, and risks

Condition

XLPE cables account for more than 50% of the subtransmission cable population. The fleet is relatively young, with a weighted average age of 16 years. The cables are in good overall condition with no known issues. Due to the importance of the subtransmission cables we intend to monitor their performance closely and plan for their renewal when required.

The oil-filled and PILC cable are the main focus of our renewal programme as they have become an obsolete technology. We have limited spares in stock, and it is getting more challenging to source joints and termination for these types of cables. We also face a shortage of skilled cable technicians to maintain these assets.

As most of our oil-filled and PILC cables have surpassed their mid-life age, accurate condition assessment is vital to determine the health of these cables. Sheath integrity tests performed on these cables indicate that the cables' sheaths are generally in acceptable condition. However, there is some oil leakage. This raises some concerns, and we are continually monitoring this.

On the four oil-filled subtransmission cables, we have carried out a comprehensive qualitative assessment considering age (against expected life), known condition, obsolescence issues, the extent of oil leakage, total maintenance cost, and the number and duration of faults. This assessment shows that the condition of one of the oil cables is becoming poor and requires replacement.

Performance

Overall, our subtransmission cable fleet is performing well, with no major events occurring in recent years.

By comparing the maintenance frequencies in each cable section, we can see an increasing trend in the frequency of maintenance of the Whangārei South–Alexander Street oil-filled cable which indicates that the cable is becoming less reliable.

A detailed analysis has been done on the variation of oil pressure in the four oil cable sections. Generally, a drop in oil pressure occurs due to oil leakage or variation in the loading pattern. It has been observed that there were some abnormal variations in oil pressure in the Whangārei South–Alexander Street cable and a consistent drop in average oil pressure.

Risks

The table below shows the key risks and mitigation measures we have identified with our subtransmission cable fleet. Redundancy built into the network design helps to reduce the immediate effects of a cable failure, as restoration is normally a time-consuming process. As significant renewals programmes are carried out over the next decade, we have a reconfiguration plan to improve the resilience to major events.

Table 9.32: Subtransmission cable risks

RISK/ISSUE	TYPE	RISK MITIGATION	MAIN RISK
Cable strike	All	Member of dial B4UDIG providing location data of the cables for design and excavation works Maintain cable depth and mechanical protection Maintain strategic spares Maintain security levels for subtransmission cables Damage to cable is limited by differential protection	Safety Network performance
Leaks in oil-filled cables	Oil-filled	Oil pressure monitoring via SCADA	Network performance Environment
Fault caused by a dry PILC cable	PILC	Damage to cable is limited by cable differential protection Maintain security levels for subtransmission cables	Network performance
Ground level change due to soil erosion or landscaping	All	Regular survey and close monitoring of the subtransmission cable routes	Network performance
Mechanical damage to the cable or cable termination	All	Routine site inspections Damage to cable is limited by differential protection Maintain secure areas for termination of cables	Network performance, Environment
Oil/grease leaks at joints and potheads due to high-head cable installation	Oil-filled/ PILC	Routine site inspections Damage to cable is limited by differential protection Maintain secure areas for termination of cables Maintain security levels for subtransmission cables	Network performance, Environment
Poor backfill materials cause overheating or sheath damage, which can cause cable degeneration or failure	All	Using quality products for backfilling as per industry standards	Network performance
Partial discharge	All	Regular monitoring and testing for early detection of partial discharge	Network performance
Lack of resilience to major natural disasters	All	Maintain security levels for subtransmission cables Formulate HILP event plans to improve resilience	Network performance

Design and build

For new subtransmission cable circuit installations, we employ single core XLPE cable. It is currently the most affordable option, and eliminates requirements, including water blocking materials[38], associated with three core cables.

The sizing of the cable is calculated based on future load growth and transfer options across the network so that the project is economical in the long term. While we are standardising cables, aluminium conductors are preferred over copper due to their lower cost and weight.

[38] Water block materials are used in three core cables prevent water entering and travelling longitudinally along a cable.

We are moving away from the historical practice of two subtransmission circuits in the same trench as it is vulnerable to common mode failure.

Box 9.20: Meeting our portfolio objective – public safety and network performance

We regularly communicate with the public to increase awareness of the safety risks associated with cable strikes. Separate trenching also helps reduce third-party-caused failures.

Due to the complexities of subtransmission cable projects, specialised service providers are used for design, manufacture, and installation. We are expecting the replacement of the Whangārei South–Alexander Street cable during FY26–FY27.

Operate and maintain

Preventive maintenance

As subtransmission cables are generally maintenance free, we rarely perform extensive preventive maintenance. Oil-filled cables require more inspections and more frequent interventions to maintain the designed oil pressure in the cable. The table below lists the regular inspection and tests to determine the condition of the cable as part of the preventive maintenance routine.

Table 9.33: Preventive maintenance subtransmission cables

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Subtransmission cable route inspection for any excavation or encroachment activity	Weekly
Oil pressure readings and visual inspection	Monthly
Subtransmission cable SVL testing, check cross bonding links and cable serving tests	Three Yearly

Apart from these periodic inspections, we also carry out HV electrical testing on these cables to ensure the insulation is still in good condition. The polarisation–depolarisation test results have highlighted some relatively minor electrical degradation in these cables.

We are hesitant to carry out detailed testing on old cables as the high test voltage required to perform the test could damage the cable insulation.

Corrective maintenance

Corrective maintenance in the subtransmission cable asset fleet is mainly related to joints, terminations, and sheath integrity. We monitor the oil pressure in our oil-filled cables via SCADA, ensuring any top-up of oil is performed before the oil pressure drops too low. Ancillary components, such as pressure gauges, alarm contacts, joints, or terminations, are periodically inspected and maintained or replaced as required.

Reactive maintenance

The work necessary to restore the cable back into service after a fault, whether the fault was unforced or forced, is included in reactive maintenance. Fault-finding and repair of underground cable faults can be expensive and time-consuming. Specialist resources are required to assist with this work.

Spares

Due to their criticality, we maintain strategic spares to ensure we can quickly return cables to service after a failure. It is becoming increasingly difficult to source spares for oil-filled and PILC cables. Spares for XLPE cables are not difficult to source as these are current technology. By replacing the aged PILC and oil-filled cables, the risk of sourcing and maintaining obsolete spares can be reduced.

Renew or dispose

The table below provides a summary of the renewal strategy for subtransmission cables.

Table 9.34: Renewal strategy for subtransmission cables

CABLE TYPE	RENEWAL STRATEGY
Subtransmission	All cables reaching an asset health index of H2 are subject to more detailed assessment, including condition assessment and an options analysis Oil-filled cables are replaced with XLPE cables Replace cable terminations upon premature failure or when cables exhibit visible deterioration that may lead to failure

During this AMP period we will start replacing ageing 33kV oil-filled underground cables with modern XLPE cables, where the circuit needs to be retained. This includes four 33kV oil-filled cable circuits with a total length of 8.5km that form part of the Whangārei city subtransmission network. These cable circuits are approaching end of life; the oldest of them was commissioned in 1965.

Renewals forecasting

Subtransmission cables are identified for renewal based on age, condition, obsolescence, and consequence of failure drivers. When a subtransmission cable is identified as being at end of life, a complete options analysis is carried out. Once a preferred option is selected, a desktop study is carried out to determine the approximate scope, cost, and timing of the project. These projects form the basis of our forecast.

Options analysis

Renewal of subtransmission cables is high-cost, time-consuming and can have an impact on network security if the cable needs to be removed before laying a new one. When a subtransmission cable is identified as being at end of life, a full options analysis is carried out to determine the preferred replacement solution.

Options for subtransmission cable replacement include:

1. refurbishment of the existing cable and associated equipment
2. like-for-like replacement of the subtransmission cable
3. review of the network architecture to improve network security and align with long-term network development plans. This can include creating meshed or ring architecture for a more reliable, resilient network
4. decommissioning of the cable.

Box 9.21: Meeting our portfolio objectives – network performance

We are assessing a meshed network of zone substations interconnected by subtransmission cables which would enable load transfer between substations. This would play a key role in strengthening network resilience around the Whangārei area and allowing load transfer between Kensington and Maungatapere regional substations.

Use of criticality in works planning and delivery

The criticality framework for subtransmission cables is being refined. At present, projects are planned on a case-by-case basis, with criticality considered during options analysis. The main factors considered are network performance, reliability, and environment.

Disposal

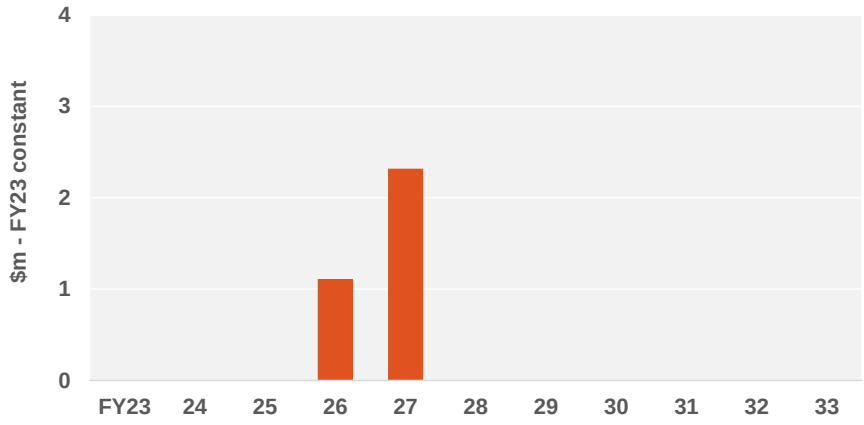
Due to the significant cost involved in retrieving the cables, we often leave the cables in-situ. With oil-filled cables, the oil is drained out to prevent it leaking into surrounding soil.

Coordination with other works

Renewal needs are coordinated with our long-term growth-related plans to ensure the solution is optimal for future requirements. We also consider laying ducts in conjunction with local roading infrastructure works where a cable may be required in the future.

Subtransmission cable expenditure forecast

Figure 9.34: Forecast subtransmission cable Capex



Over the planning period we have only planned one subtransmission cable for replacement, the Whangārei South to Alexander Street cable. This is currently planned for FY26–FY27

Benefits

The primary benefit of our planned subtransmission cable renewal work is maintaining the current network performance levels and reducing environmental risk.

Box 9.22: Meeting our portfolio objectives – environmental and sustainability

Leaking oil-filled cables are being replaced with XLPE cables to manage oil-related environmental risk.

9.5.3. Distribution and LV cables

Distribution and LV cables fleet overview

This section describes our portfolio of underground distribution and LV cables. These assets also include joints, terminations, and other ancillary cable equipment. Different types of cable insulation have been used over the years, including XLPE, PILC, and PVC. XLPE is now the standard cable type used on our underground LV and distribution networks.

Oil-filled or insulated PILC cables are no longer installed but remain in service. Cables can be single-multi cores and may have armouring depending on the application. Most older cable installations were direct buried, while the most recent ones are installed inside ducts.

Distribution cables operate at 11kV to transport electricity from our zone substations to distribution substations. We have approximately 302km of distribution cable. The distribution network has grown significantly over the last 30 years, and these assets are young in comparison to their expected life, so renewal levels are relatively low.

The primary focus of the distribution cable fleet over the AMP period is the replacement of cast-iron potheads, an obsolete termination type used on PILC cables. These pose a major public safety risk due to their explosive failure mode.

Our LV cables operate at 400/230V, transmitting electricity from our distribution substations to customers and streetlights. Due to voltage drop limitations, LV cable sections tend to be much shorter compared to HV distribution cables. As these are younger assets, we manage these assets reactively. LV cables also have cast-iron potheads that are scheduled for replacement over the planning period.

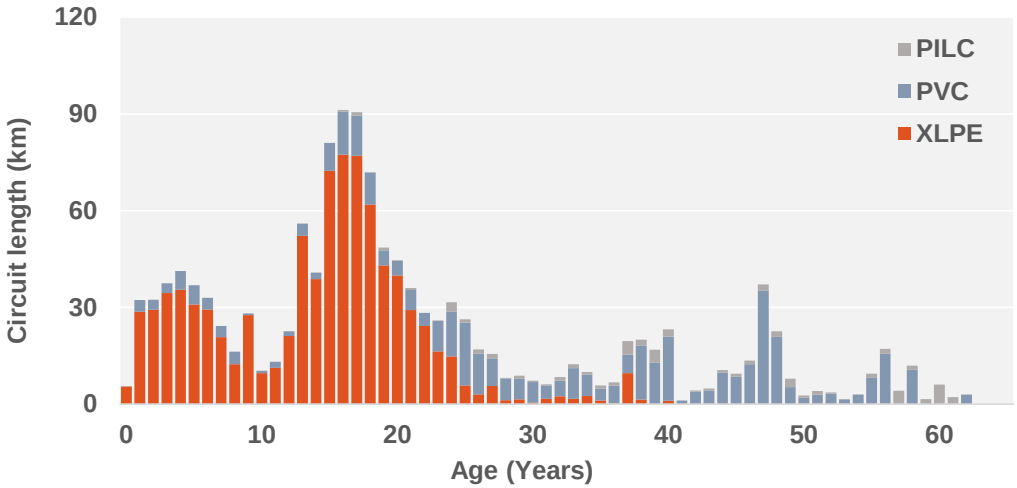
Population and age

The table below summarises our population of distribution and LV cables.

Table 9.35: Distribution and LV cable population by type

CABLE TYPE	DISTRIBUTION (KM)	LOW VOLTAGE (KM)
XLPE	254	628
PVC	0.5	431
PILC	48	12
Total	**302**	**1,071**

Figure 9.35: Distribution and LV cable age profile



Overall, distribution and LV cable asset age is relatively young compared to expected lives. The average age of our distribution cables is 18 years and that of LV cable is 22 years.

Condition, performance, and risks

Condition

In general, our distribution and LV cables are relatively young and in good condition. However, there are some specific design and installation issues that are being addressed.

Underground cables condition is impacted by numerous factors: insulation type, outer sheath design, corrosion, soil type/environment, installation type, age, third-party damage, and loading history.

In earlier years, the LV XLPE insulation layer was not UV stabilised. When exposed to above-ground environmental conditions, the insulation can become brittle and crack, allowing moisture ingress over time. This was particularly true where cables were located along poles to connect to the overhead networks. We currently install UV-stabilised tubes over the cable installations to protect them from direct sunlight.

We have also identified some older underground breech or tee joints showing increasing failure rates, due to moisture ingress through the epoxy joint. This issue is not widespread; however, we are closely monitoring where this is happening. A replacement programme has been initiated to identify and replace the joints when required.

We also have several cast-iron pothead cable terminations on our network. These potheads are prone to moisture ingress if left out of service for some time and can catastrophically fail, posing a public safety risk. We have been proactively replacing these, and we plan to complete these replacements over this planning period.

Box 9.23: Meeting our portfolio objectives – public safety

We replace obsolete cast-iron potheads with low risk terminations. This reduces risk of public injury from cast-iron potheads that can catastrophically fail.

Performance

We assess the reliability and performance of LV and distribution cable networks based on historical outage data.

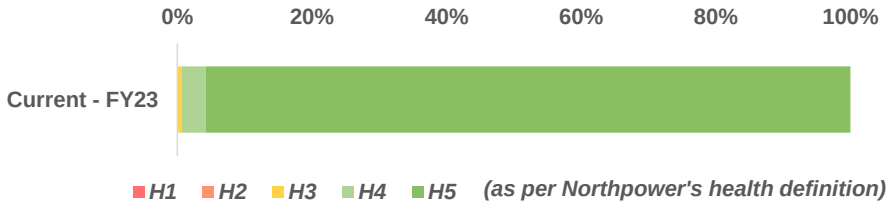
Our distribution cables are performing well; however, we have had some recent failures in the Whangārei CBD on some of our older PILC cables. They are being replaced over the next couple of years. We have a high level of security in the CBD and so failures in this area rarely lead to significant outages.

Our ability to analyse LV performance is limited. However, we are improving our historical outage data to include more detail on LV faults so we can better analyse them in future. Based on current data, the LV cable network is performing well. Most LV cable failures are caused by third-party activity and ground movement. Older PILC cables are susceptible to damage when moved, so ground disturbance can cause damage and lead to failure.

Asset health

The AHI for the distribution and LV cables is given below. Our fleet is relatively young, so our distribution and LV cables are in good overall health condition.

Figure 9.36: Distribution and LV cable current asset health



We expect to replace 0.6% of distribution and LV cable over the next 10 years.

Risks

Table 9.36: Distribution and LV cable risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Cable strike – external factors	Dial B4UDIG service Following installation standards Cable depth requirements Maintaining strategic spares	Safety Network performance
Overloading of cable	Monitor voltage and power quality Sizing of cables considering load growth	Network performance
Cast-iron cable termination explosive failure	Targeted replacement programme	Safety Network performance
Damage in UG – overhead cable termination – UV damage	Fitting of UV-stabilised tubes Monitored during pole inspection	Safety Network performance
Damage to cable during installation	Use of quality backfill materials Appropriate installation procedure	Network performance

Design and build

Our preferred cable is XLPE. We use single core XLPE for shorter runs and three core XLPE cables for longer runs. Replacing cast-iron potheads can requires significant work to meet modern clearances on the pole. We may need to run new XLPE cable tails down the pole and join the XLPE tails to the existing PILC cable below ground or replace the pole.

The design and construction standards that we follow for LV cables are similar to those for distribution conductors. We normally use three core aluminium XLPE cables with neutral screen for the installation of LV cables. The cables are sized to maintain the regulatory voltage and required current rating to the furthest customer from the distribution transformer.

We have instances of cable strikes due to third-party works reducing ground levels. When these occur, the affected cable sections are re-laid to a correct depth. Most of the construction activities around digging and re-laying of underground cables include significant civil works, and we often employ external contractors to complete these tasks. We have an in-house design team that carry out scoping, design, project engineering, and standards development.

Operate and maintain

Preventive maintenance

The preventive maintenance regime for distribution and LV cables is summarised below.

Table 9.37: Distribution cable preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection and thermal testing of HV cable terminations as part of ground-mounted distribution substation inspection	Two yearly
Visual inspection and thermal testing of LV cable terminations as part of ground-mounted distribution substation inspection	Two yearly
Visual inspection and voltage testing of LV pillars	Two yearly

Corrective maintenance

Corrective maintenance of distribution and LV cables is planned work to fix defects identified during preventive maintenance, or as a second response works after a fault. Replacement of joints or terminations is also carried out as corrective maintenance.

Reactive maintenance

Reactive maintenance on distribution and LV cables includes restoring the cables to service following a fault. Faults in cables can occur due to an inherent problem with the cable, ground movement, or third-party interference. Locating and repairing cable faults can be significantly more expensive and time-consuming than repairing faults on overhead lines.

Spares

We maintain spares on hand in order to quickly respond to faults. Having standardised cable sizes enables more effective spares management.

Renew or dispose

Distribution cable expenditure is mostly reactive in response to a failed test result or a fault. We use industry-standard life expectancy to forecast expenditure requirements. We have an ongoing programme to replace cast-iron cable terminations based on public safety criticality.

Renewals forecasting

We use a Repex approach to forecast distribution and LV cable renewals. We use different expected lives depending on the type of cable, generally aligned with industry. Unit rates are based on the expected average cost to replace a kilometre of cable. A separate unit rate is used for cast-iron pothead replacements.

Options analysis

Our options for managing LV and distributions cables are currently limited to replacing or repairing sections of damaged cable and/or terminations, or replacement of the entire cable.

We consider the remaining life and condition of the pole and ancillary components on which the cast-iron pothead replacements are planned and adopt the most cost-effective solution.

Use of criticality in works planning and delivery

We do not use criticality for distribution and LV cable replacements; however, we do prioritise the replacement of cast-iron cable terminations based on public safety criticality.

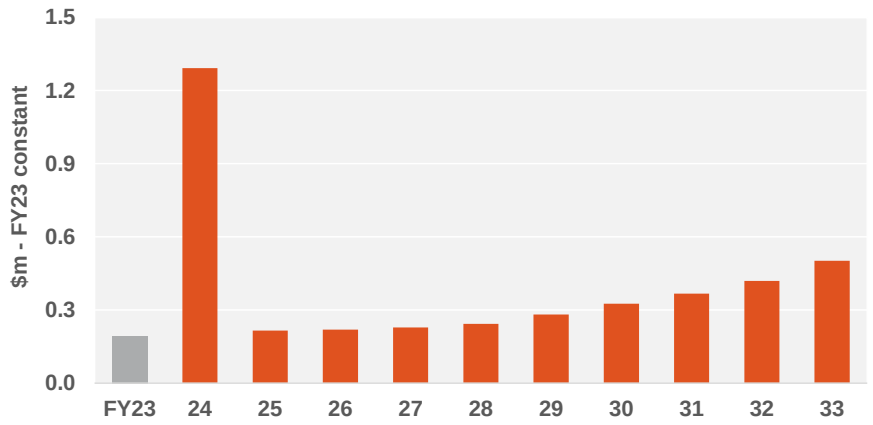
Coordination with other works

Replacement of remaining cast-iron potheads is the main focus during the planning period. In addition to proactively planning work in prioritised zones, we will also carry out this work opportunistically when terminations are de-energised for other work.

Distribution and LV cable expenditure forecast

Due to the young age of our distribution and LV cables our historical spending has been low. We expect to slowly ramp up expenditure as the fleet ages. Our forecast of LV and distribution cables for the planning period is shown below. In FY24, we plan to replace a section of submarine cable that has reached its end of life and is in poor condition.

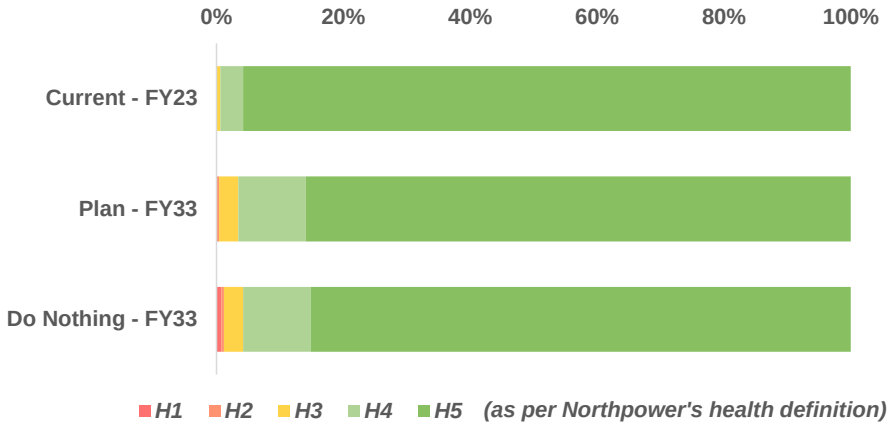
Figure 9.37: Forecast distribution cable Capex



Benefits

Replacing cast-iron pothead terminations will reduce public safety risk. We also expect to manage our ageing fleet. The chart below compares current asset health with projected asset health in 2033 following planned renewals, as well as a do nothing scenario.

Figure 9.38: Projected distribution and LV cable asset health



9.6. Distribution equipment

This section describes the distribution equipment portfolio and the asset management plan associated with these asset fleets. This portfolio includes four asset fleets:

- distribution transformers
- ground-mounted switchgear
- low-voltage distribution units
- pole-mounted switchgear.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational, and maintenance approaches and provides expenditure forecasts for the planning period.

Box 9.24: Portfolio Summary

We expect to increase our investment in distribution equipment to $39.4 million over the planning period. Mainly for renewal of our distribution transformer and switchgear assets.

We have forecast this portfolio based on age, condition, and known type issues. Our distribution equipment focus is on maintaining our network performance as our fleets age and managing any environmental and safety risk associated with these assets.

As part of our programme, we will also improve our remote switching capability as we carry out renewals of our distribution switchgear to improve the reliability of our network.

9.6.1. Distribution equipment portfolio objectives

Our portfolio objectives for the distribution equipment portfolio are listed below.

Table 9.38: Distribution equipment portfolio objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Public safety	No injuries or fatalities from explosive failures or maloperation of switchgear or fires from distribution transformers Installations comply with seismic standards Phasing out our larger pole-mounted transformers in favour of ground-mounted equivalents to limit seismic and working at heights risk exposure.
Network performance	Increase use of remote switching capable equipment to improve fault isolation and restoration times for customers Downward trend in distribution equipment failures Minimise planned interruptions by coordinating with other works
Supporting communities	Reduce fleet diversity over time to optimise asset whole of life costs
Environment and sustainability	No uncontained oil spills or significant SF_6 leaks from our distribution equipment assets Removal of graffiti from assets caused by third parties Phasing out SF_6 distribution equipment assets as technology improves and becomes economic

9.6.2. Distribution transformers

Distribution transformers fleet overview

Distribution transformers can be pole or ground mounted. They typically transform voltage from 11kV to 400/230V to supply consumers. A typical modern ground-mounted transformer is shown below. Distribution transformer sizes depend on the downstream load they supply. Pole-mounted transformers are typically smaller than ground mounted.

Figure 9.39: Ground-mounted distribution transformer

As most distribution transformers are oil filled, they pose environmental and fire hazards. Appropriate lifecycle management including disposal when decommissioned, is critical for protecting the public and limiting any environmental impacts.

Some of our distribution feeders cover relatively large distances. For these very long overhead feeders, voltage regulators are installed at intervals along the line to maintain the voltage to acceptable levels.

Population and age

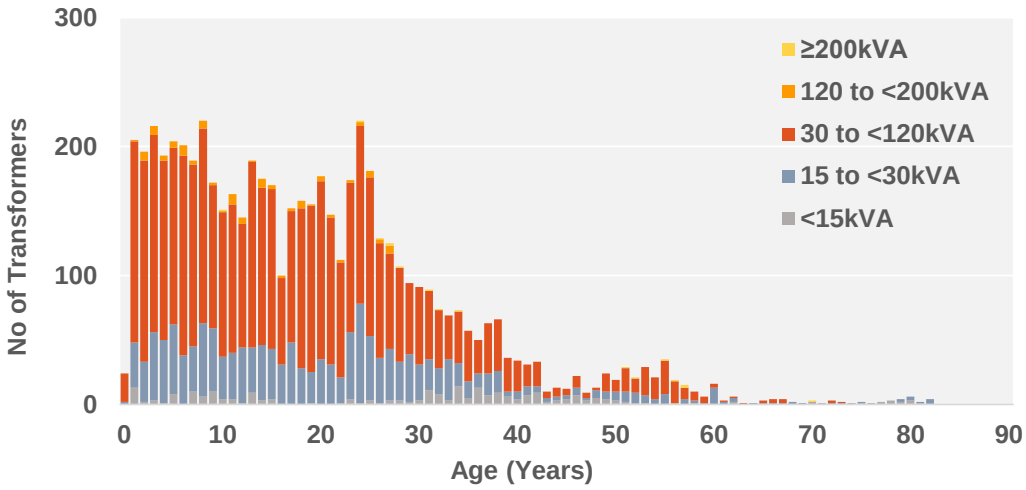
Pole-mounted distribution transformers

There are approximately 6,000 pole-mounted transformers on our network. The capacity ranges from less than 5kVA to 300kVA. Most of them are in between 30kVA to 120kVA in size and typically supply a few houses in a rural area.

Table 9.39: Pole mounted distribution transformer population by rating

RATING (KVA)	NUMBER OF TRANSFORMERS	PERCENTAGE
<15	255	4%
15 to <30	1,495	25%
30 to <120	4,137	69%
120 to <200	106	2%
≥200	16	~0.3%
Total	**6,009**	**100%**

Figure 9.40: Pole mounted distribution transformer age profile



These units normally have a life expectancy of 45 to 55 years. Our pole-mount transformer fleet is still relatively young, with the majority less than 30 years old. The average age is 19 years. There are a few older units across the network that are reaching their end of life and will require replacement during the planning period.

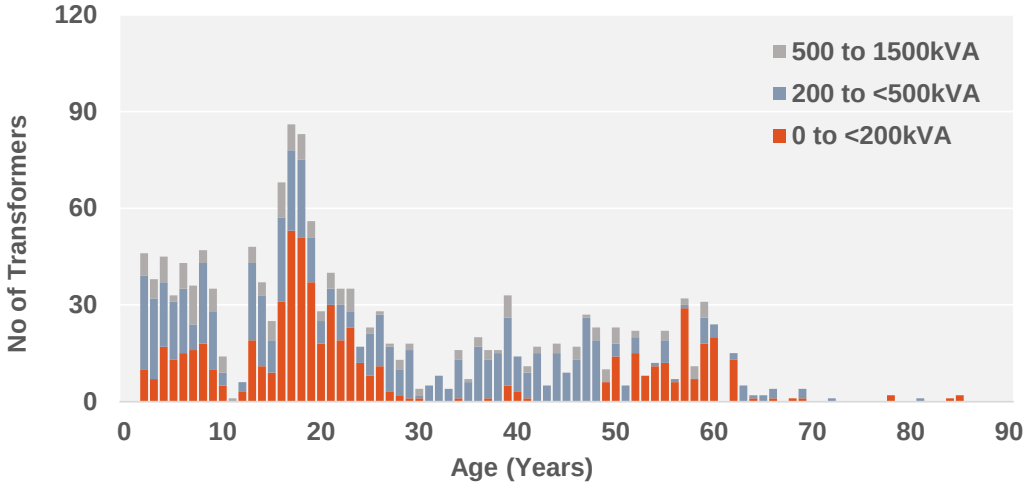
Ground-mounted distribution transformers

Our network has about 1,500 ground-mounted distribution transformers. These are usually located in suburban and CBD regions with underground networks, or they serve larger commercial or industrial sites. Most of our ground-mounted transformers are <500 kVA. We have around 200-ground mounted transformers between 500 kVA and 1,500kVA serving higher capacity installations or larger groups of customers.

Table 9.40: Ground-mounted distribution transformer population by rating

RATING (KVA)	NO OF TRANSFORMERS	PERCENTAGE
0 to <200	634	42%
200 to <500	690	45%
500 to 1500	197	13%
Total	**1,521**	**100%**

Figure 9.41: Ground-mounted distribution transformer age profile

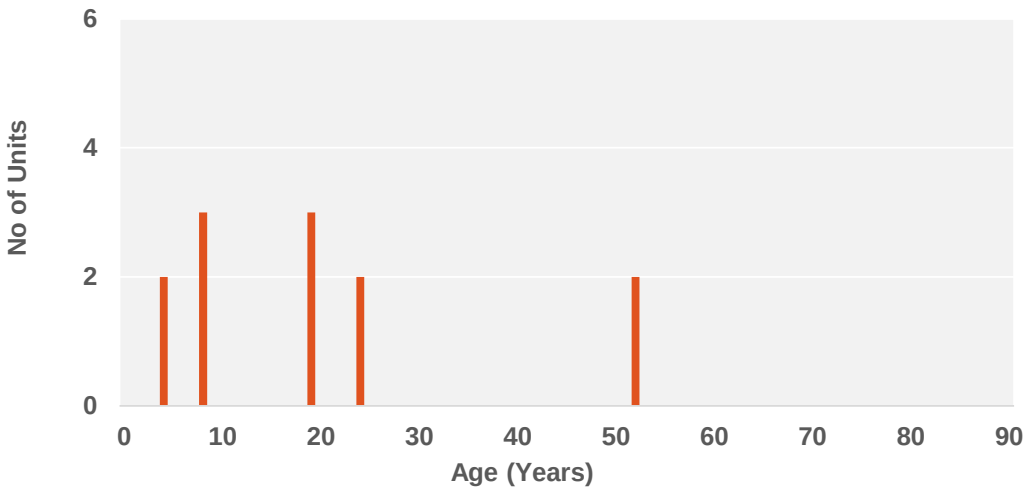


Most ground-mounted transformers are at mid-life with an average age of 26 years. Generally, ground-mounted transformers have a longer life expectancy than pole-mounted units, of around 50–60 years. Some older units on the network are nearing the end of their service life and will be replaced during the planning period.

Voltage Regulators

We have 12 voltage regulators. The life expectancy of voltage regulators is 60 years, and the current average age is 20 years. We have two 3-phase voltage regulators nearing the end of their service life that will likely require replacement in 10–15 years.

Figure 9.42: Voltage regulator age profile



Condition, performance, and risks

Condition

Failure of distribution transformers can have safety, environmental, and reliability consequences. Corrosion on distribution transformers can lead to oil leaks.

The primary drivers for condition-based replacement of distribution transformers are age, corrosion, and failures triggered by third-party interferences or lightning strikes. Factors contributing to degradation are moisture, consistent overloading, oil leaks, and corrosion.

We normally do not perform detailed tests on pole-mounted transformers. Defects are picked up with five-yearly visual inspections. We do not currently hold detailed condition data for our distribution transformers.

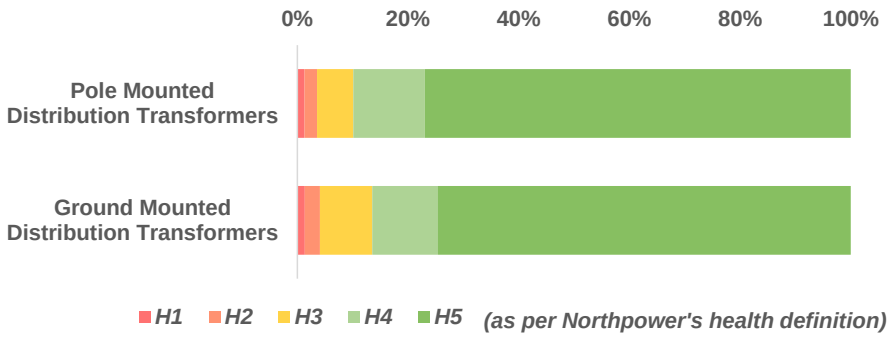
Performance

Our distribution transformers have generally performed well in the past, with relatively few failures. Overloading and voltage rise issues have emerged in some parts of the network, particularly as a result of growing renewable energy penetration. We are monitoring these transformers to determine whether they need to be upgraded.

Asset health

The distribution transformer fleet health is generally good, with a small number of assets categorised as H1. We have a further 10% of pole-mounted distribution transformers and 14% of ground-mounted distribution transformers classified as H2 and H3 – requiring intervention over the planning period.

Figure 9.43: Distribution transformer current asset health



Risks

The table below sets out the key risks identified in the distribution transformer fleet.

Table 9.41: Distribution transformer risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Overloading of distribution transformers	Inspections and MDI reading	Reliability
Oil leaks	Maintenance and asset renewal	Environment and sustainability
Damage caused by third party	Installation of warning signs Sensible transformer location	Safety
Internal failure	Maintaining strategic spares Preventive maintenance	Network performance
Transformer noise due to ferro-resonance	Inspection and follow up actions Replacement plans	Environment and sustainability

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Distribution transformer explosion – active part failure, bushing failure, cable box failure	Safety in design solutions Preventive maintenance	Network performance Environment and sustainability Safety
Vegetation growth around transformers	Regular inspections and corrective maintenance	Network performance
Issues with transformer earthing	Periodic testing of earth resistance Corrective maintenance	Safety
Seismic risks	Pole- to ground-mounted conversion Renewal plans	Safety
Electrocution risks	Signage to inform associated risks	Safety
Flooding	Avoid flood-prone areas during installation	Network performance Safety

Design and build

Our standard design of pole-mounted transformers uses HV outdoor bushings, allowing direct connection to the overhead line through a drop-out fuse and lead arrangement. The low voltage 400/230V side of the transformer is connected through a set of fuses to the LV lines that are located below the high voltage ones.

Ground-mounted transformers distribute electricity to consumers via underground cables and are typically mounted on the ground in the road reserve or in front of the customer's premises. The HV is supplied to the ground-mounted transformer via a cable through fuses connecting to the HV overhead network, or from a ring main unit. The LV side of the transformer includes fuse switches which connect to the LV cables supplying consumers.

We have standardised ground-mounted transformer sizes to simplify maintenance and spare management. We continuously monitor the load and renewable energy penetration on each distribution transformer to avoid voltage issues. Hazards like third-party interference, vehicle traffic, and fire risks are addressed during the design process.

To ensure that transformers are seismically compliant, the general practice is to ground mount any pole-mounted transformers above 300kVA. We ensure the support structures for our ground-mounted transformers are complaint with existing seismic standards. During the installation of distribution transformers, care is taken to ensure that ECP34 clearance and safety requirements are met.

Operate and maintain

Preventive maintenance

Pole-mounted transformers do not require frequent maintenance. In most instances, maintenance is limited to visual checks, with repair or replacement due to poor condition.

Ground-mounted transformers are more accessible to the public and generally have a higher criticality than pole-mounted transformers. Ground-mounted transformers have more rigorous visual inspections as they are more accessible. Components such as

switchgear, fuses, underground cable connections, and terminations are included in these inspections.

Preventive maintenance of distribution transformers highlights deterioration issues requiring remedial action. Depending on the priority of the identified defect, these are addressed as corrective maintenance.

Table 9.42: Distribution transformer preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of ground-mounted and pole-mounted voltage regulators and thermal image survey	Yearly
Voltage regulator acoustic emission survey	Two yearly
Voltage regulator controller, communication and regulating relay testing	Two yearly
Visual inspection of ground-mounted transformers including detailed condition assessment including thermal testing, partial discharge, and acoustic emission testing	Two yearly
Voltage regulator oil change	Four yearly
Visual inspection of pole-mounted transformers as part of overhead network inspections	Five yearly

Corrective maintenance

Typical corrective work on a pole-mounted transformer includes the replacement of corroded hanger arms and topping up oil. Severely rusted pole-mounted transformers that have not reached end of life may be repaired in the workshop.

Common corrective maintenance on ground-mounted transformers is levelling base pads where there has been land movement, removal of vegetation, and removal of graffiti. As with pole-mounted transformers, we repair transformers where it is cost-effective.

Reactive maintenance

The most common reactive maintenance activity is replacement of fuses and surge arrestors after a fault. There have been instances of car versus transformers, and cases of internal, tank, or bushing damage, which require a new transformer.

Spares

We keep spare distribution transformers in stock. We have standardised ratings, which makes spares management easier. Spares for some legacy units are sourced when required. Units swapped under corrective maintenance, depending on spares availability and population, are evaluated to determine whether repair is cost-effective. If so, the unit can be kept as a spare.

Renew or dispose

Pole-mounted transformer replacement is generally driven by condition. For efficiency, the pole, crossarm, and other components are considered for replacement at the same time. Some larger pole-mounted transformer structures are not seismically compliant. The single or H-pole mounted structures that do not meet the ECP34 clearance and safety requirements are replaced with compliant pole-mounted or ground-mounted units.

Ground-mounted transformer replacements are based on condition. For indoor units, the condition of the building is also assessed for suitability of the replacement transformer.

Voltage regulators are replaced on condition. This can also be driven by how many operations it has carried out.

Renewals forecasting

We forecast ground-mounted and pole-mounted transformer renewals using the Repex methodology, using standard expected lives for each type of transformer. Our unit rates are based on the expected average cost to replace either a pole- or ground-mounted unit.

Our voltage regulator expenditure is forecast based on an individual assessment of the assets in our fleet. We use a standard unit rate to estimate the cost of replacement.

Options analysis

When a pole-mounted transformer is identified as end of life, options are considered, such as like-for-like replacement, replacing with a ground-mounted transformer, or repair. Generally, the preferred option is to replace the transformer with the modern equivalent in line with current design standards.

For ground-mounted and pole-mounted transformers, options such as like-for-like replacement, repair, and replacement are considered. It is generally cost-effective to replace pole-mounted transformers when they are approaching end of life rather than refurbishing to extend its life. Load growth and DER penetration are considered when sizing a replacement.

For voltage regulators identified as end of life, a review of need is carried out. Considered options include like-for-like replacement, relocation, refurbishment, and retirement.

Coordination with other works

We coordinate transformer replacements with other distribution equipment replacements where possible. This is done to reduce required outages and associated traffic management costs.

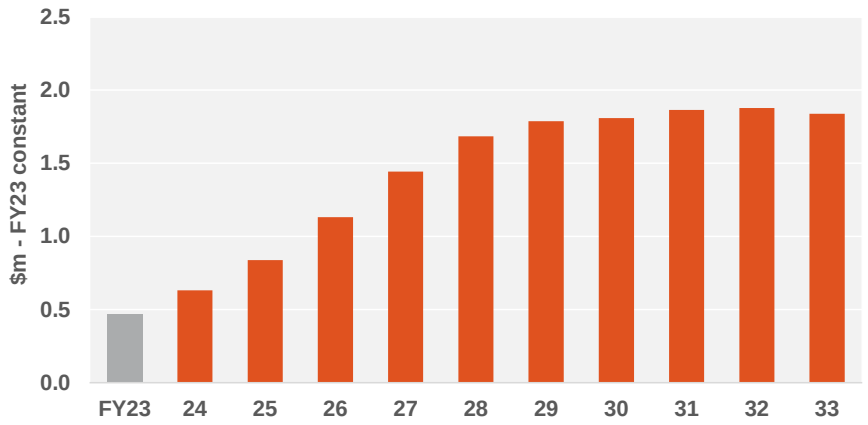
Disposal

If it is the most economic option, we dispose of distribution transformers at end of life. These are generally recycled after disposing of the transformer oil appropriately.

Distribution transformer expenditure forecast

The expenditure forecast for the distribution transformer fleet is shown below.

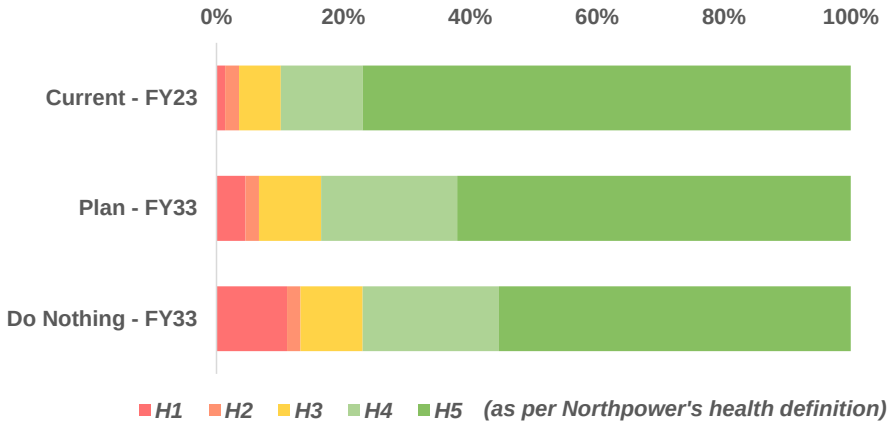
Figure 9.44: Forecast distribution transformer Capex



Benefits

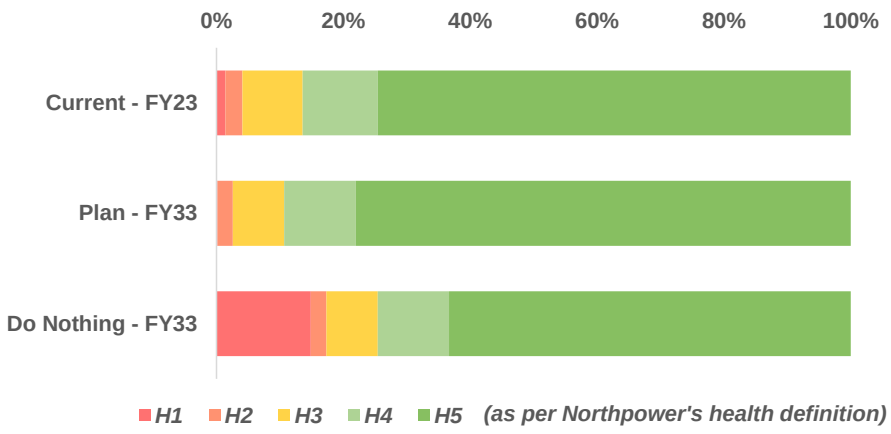
The main benefit of our investment over the AMP period is to ensure volumes of assets classified as H1 remain low. The do nothing scenario presents the counterfactual. If no investment was made, a significant portion of our pole-mounted transformers would be in poor health by FY33.

Figure 9.45: Projected pole mounted distribution transformer asset health



The benefit of ground-mounted renewals is similar to pole-mounted. Investing in this fleet enables us to keep the number of assets classified as H1 at a low level. If no investment was made the proportion of H1s would climb to 17%.

Figure 9.46: Projected ground mounted distribution transformer asset health



Ensuring the number of assets in poor health is kept low decreases the probability of failures occurring and reduces the risks associated with these assets.

9.6.3. Ground-mounted switchgear

Ground-mounted switchgear fleet overview

Ground-mounted switchgear offers isolation, protection, and switching options in distribution networks. Assets included in the ground-mounted switchgear are ring main units (RMUs), switches, fuse switches, links, and associated enclosures.

RMUs perform switching and isolation functions between cable circuits. In addition, they provide fuse protection and isolation functionality to distribution transformers. Before the mid-2000s we used oil-filled switchgear (RMUs and ground-mounted switches), but we no longer purchase these due to obsolescence and safety risk concerns. We now predominantly install SF_6 insulated switchgear. Generally, these are arc contained.

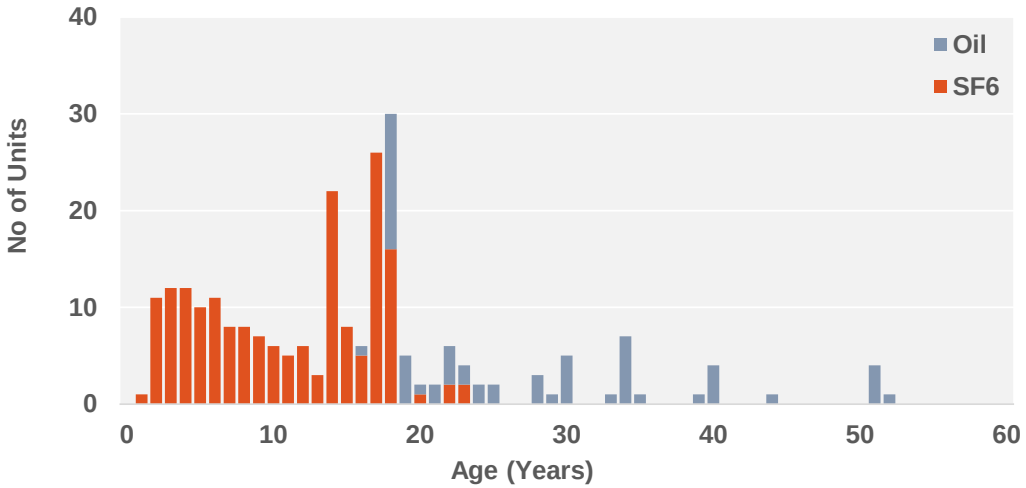
Population and age

The table below lists numbers of ground-mounted RMU by insulation medium. Most of the fleet uses SF_6 as insulation medium, and most of the older units use oil.

Table 9.43: Ground-mounted RMU by insulation medium

GROUND-MOUNTED SWITCHGEAR	INSULATION MEDIUM	TOTAL
Ring main units	Oil	63
	SF_6	183
Total		**246**

Figure 9.47: Ground-mounted switchgear age profile



Our ground-mounted switchgear fleet is relatively young, with an average age of 15 years. Oil switchgear has an average age of 28 years, and SF_6 switchgear average is 11 years.

Condition, performance, and risks

Failure of ground-mounted switchgear in service can be a significant safety concern, as it can be near the public and pose electrocution and arc flash risk. It also poses a reliability risk, as failure often results in a loss of supply to customers. It is critical that ground-mounted switchgear failure modes are identified and mitigated.

Condition

Older oil-filled ground-mounted switchgear installed from the early 1960s to the mid-2000s has the highest safety risk and failure consequence. It does not have arc fault containment, and its oil can increase the risk of a fire if there is a fault. A significant proportion of our ground-mounted switchgear fleet is located outdoors. Switchgear degrades faster in outdoor environments because of rust, particularly in coastal areas of the network, and this makes these models susceptible to failure from moisture ingress. The older indoor RMUs in the network, which are normally housed in a kiosk or building, are generally in good condition for their age. Newer SF_6 switchgear models are in good condition.

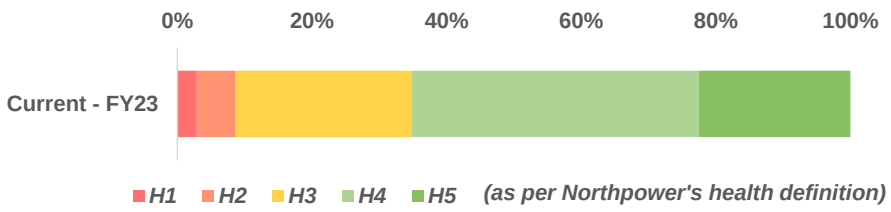
Performance

After a series of recent operating incidents in our industry, we are planning to phase out oil insulated switches from the network. We have also experienced failures on existing operating mechanisms in oil-filled switchgear. We have an existing programme to upgrade these while we are investigating further actions and replacement options.

Asset health

We have formulated AHI for ground-mounted switchgear based on the remaining life of the asset. Around 5% of our ground mounted switchgear has reached end of life (H1) and is scheduled for replacement. The predominant driver for this is ageing oil switchgear. We expect 35% of ground-mounted switchgear to be replaced over the next 10 years.

Figure 9.48: Ground-mounted switchgear current asset health



Risks

The below table discusses risks associated with the ground-mounted switchgear fleet.

Table 9.44: Ground-mounted switchgear risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Safety concerns – oil-filled RMUs	Operating procedures Renewal programmes	Safety
Risk of potential arc flash	Remote operation through SCADA wherever applicable Maintenance undertaken while de-energised New ground-mounted switchgear replacements are arc flash contained	Safety
Damage caused by third party	Installation of warning signs Inspection and replacement of locks Choice of location during installation	Safety
SF_6 leakage	Periodic checking of pressure gauge Trained person to handle SF_6	Environment and sustainability

Design and build

All new ground-mounted switchgear is suitably rated to contain arc flash failures. New switchgear can also be remotely operated. The remote operation may shorten the time needed to restore service following an outage, as well as improve worker safety.

We moved away from installing ground-mounted oil-switchgear in the mid-2000s. Currently all new ground-mounted switchgear installations are of SF_6 type due to its arc quenching properties and reliability. For environmental reasons, we are moving away from SF_6 type switchgear where economic and are exploring other options.

Operate and maintain

Preventive maintenance

To ensure the safe operation of our network, regular inspection and maintenance of ground-mounted switchgear is vital. Switchgear enclosures must always be locked and secured as they are often located in public areas. Preventive maintenance tasks are summarised below.

Table 9.45: Ground-mounted switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of ground-mounted switchgear including detailed condition assessment, thermal testing, partial discharge, and acoustic emission testing	Two yearly
Service ground mounted oil filled HV switches	Eight yearly

Corrective maintenance

Components in switchgear deteriorate with time due to environmental exposure and system conditions, including switching operations performed. Older oil-type ground-mounted switchgear requires more rigorous and frequent maintenance than SF_6 switchgear. Common corrective maintenance activities for ground-mounted switchgear include oil replacement, internal inspection, and minor repairs to ensure the fleet operates safely. Normally ground-mounted switchgear is berm mounted and is exposed to weather and vegetation growth.

Reactive maintenance

Replacement of fuses after a fault is the most common reactive maintenance. Other damage to ground-mounted switchgear may require component or unit replacements.

Spares

Most of our oil-filled ground-mounted switchgear is now obsolete and has no support from the manufacturers for the supply of spares. We maintain a limited number of critical spares for these models. Once a unit is removed from service it is either scrapped, refurbished, or maintained as a spare. The general strategy around spares management is to maintain spares for items with long lead times or that are not part of the standard inventory.

Renew or dispose

Renewal decisions are based on risk priority, combining likelihood and consequences of failure, safety of the public and field service personal, and the environment. This approach ensures expenditure is prioritised towards equipment with the highest risk.

Renewals forecasting

We use a Repex approach to forecast renewal of ground-mounted switchgear. We use different expected lives depending on the type of switch, generally in alignment with others in the industry. Our unit rates are based on the expected average cost to replace a ground-mounted switch.

Options analysis

When a ground-mounted switchgear asset requires replacement, we analyse options and invest in the most long-term cost-effective solution. Replacement, repair, or network reconfiguration are the most common options available. We install modern equivalent SF_6 RMUs because they have modern safety features and need less ongoing maintenance.

Disposal

Once a ground-mounted switch is decommissioned, it is either kept as a spare or scrapped. The decision is taken on case-by-case basis. Factors such as model, number of units on the network, and age of the unit are considered. Components like steel, copper, and oil are recycled and SF_6 from the RMUs is removed so specialists can safely dispose of it.

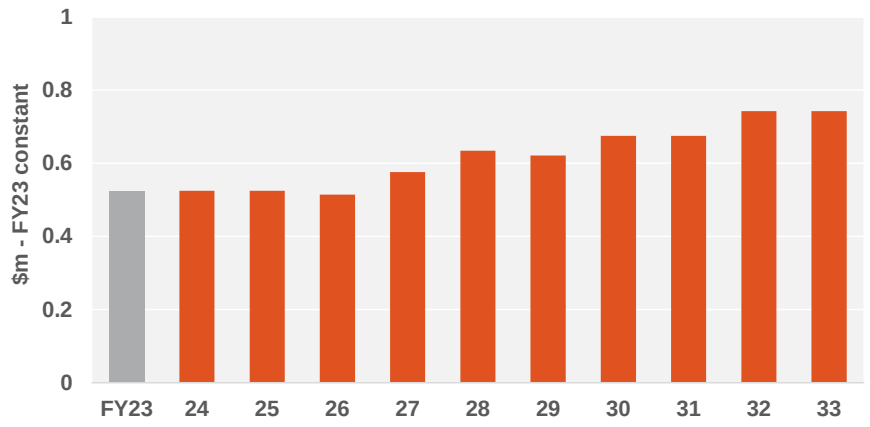
Coordination with other works

We coordinate replacements with underground cable or ground-mounted transformer renewals wherever possible. This reduces required outages and costs.

Ground-mounted switchgear expenditure forecast

The expenditure forecast for the ground mounted switchgear fleet is shown below.

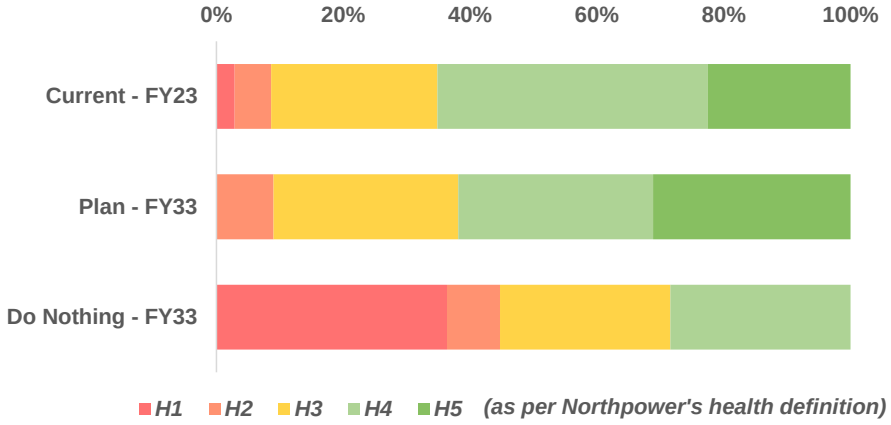
Figure 9.49: Forecast ground-mounted switchgear Capex



Benefits

The main benefit of our planned investments is that it will reduce safety and operability risks associated with obsolete models. It will also phase out oil ground-mounted switchgear. The chart below compares the projected AHI in FY33 following planned renewals, with a counterfactual do nothing scenario. This comparison illustrates the benefit of the renewals.

Figure 9.50: Projected ground-mounted switchgear asset health



Our planned investments will improve overall fleet health and help manage the risks associated with asset failure. Around 3% of our ground-mounted switchgear fleet is H1. Following our planned programme, we will have no H1 assets by FY33. Under a hypothetical do-nothing scenario, H1 assets would increase to 33% by FY33.

9.6.4. Low-voltage distribution units

LV distribution units fleet overview

The LV distribution fleet is made up of cabinets and pillars. The customer service cable runs between the customer switchboard and the pillar box, which is usually located on the property boundary. Distribution pillars and cabinets are installed on the LV distribution network to enclose links, fuses, and joints. These also link distribution circuits, disconnection points for distribution circuits, and service fuses for customer connection.

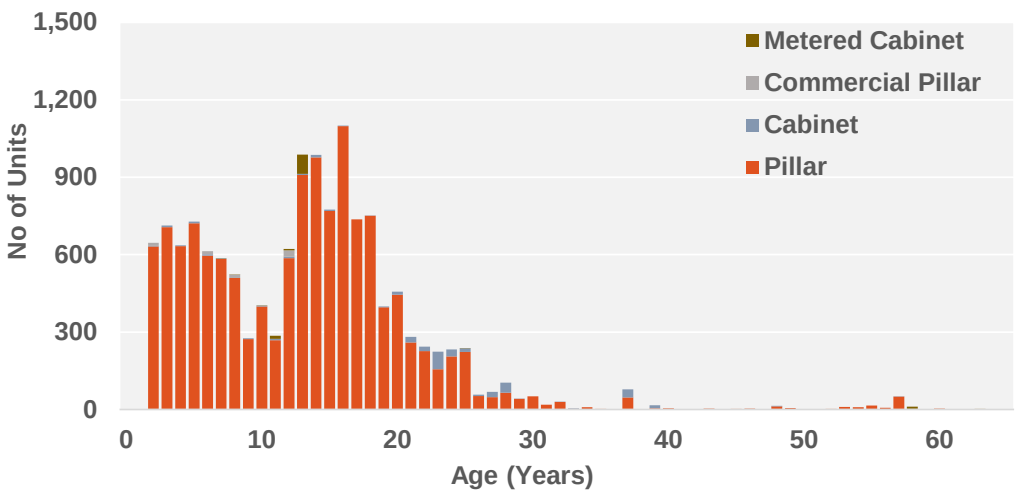
Population and age

Detailed data on the LV fleet is incomplete, as the age or year of manufacture has not typically been recorded. We are capturing data to fill these gaps. Currently, we have 14,068 LV distribution units, with approximately 96% of the asset population being pillars and the remaining units being cabinets and metered cabinets.

Table 9.46: LV distribution units population by type

DISTRIBUTION UNIT TYPE	NO OF UNITS	PERCENTAGE
Pillar	13,555	96.4%
Cabinet	344	2.4%
Commercial pillar	61	0.4%
Metered cabinet	108	0.8%
Total	**14,068**	**100%**

Figure 9.51: LV distribution units age profile



The assets have a relatively young age profile, with an average age of 13 years.

Condition, performance, and risks

Condition

Regular inspections and condition assessments on pillars and cabinets have highlighted some corrosion issues requiring remedial action or replacement. We are addressing these issues as defects. We have also identified type issues with some models that have inadequate safety clearances and overheating of contacts and fuses. These assets are generally replaced reactively or alongside works being carried out in the area.

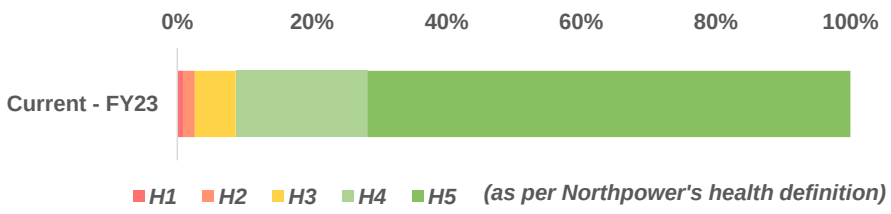
Performance

Overall, our LV distribution unit fleet performs well. Many of the identified faults result from damage caused by vehicles. Although an LV box may be installed in a safe position initially, further development in the area might make it vulnerable to third-party damage. Relocation, underground distribution pits, or protective concrete blocks can prevent future failures.

Asset health

The figure below shows the asset health of our LV distribution unit fleet.

Figure 9.52: LV distribution unit current asset health



Around 1% of H1 assets have been tagged as end of life and are identified for replacement within a year. We expect to replace 9% of LV distribution units over the next 10 years.

Risks

The table below summarises the key risks identified on our LV distribution unit fleet.

Table 9.47: LV distribution units risk

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Water ingress on pillars and cabinets	Safety risk controlled by DNO	Safety
Metallic structures can be live due to high impedance faults	Test before touching the equipment Inspection programme Corrective maintenance to retrofit plastic lids Replacement programme	Safety
Third-party damage	Regular inspection programme Public reporting Corrective maintenance Replacement programme	Safety Network performance
More frequent and severe extreme events (floods, droughts, high winds)	Implement more rigorous structural standards	Safety Network performance

Design and build

We require pillars and cabinets to be manufactured from suitably rated non-conductive material, removing the risk of internal faults livening the box. The position of the pillar must be carefully considered to reduce the risk of vehicle impacts and pedestrian movements.

Operate and maintain

Preventive maintenance

The focus of preventive maintenance of the LV distribution unit fleet is inspection of LV pillars and cabinets. We also conduct detailed condition inspections. The table below summarises the inspections of the LV distribution fleet.

Table 9.48: LV distribution units preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection and voltage testing of LV pillars	Two yearly

Corrective maintenance

Corrective maintenance of LV enclosures includes changing fuses or re-terminating LV cables that show signs of overheating. Other activities include replacing seals, remounting loose plastic lids, renewing or applying labels, and fixing ground connections. We also replace the metal enclosures with plastic to limit the risk of the enclosures being energised.

Reactive maintenance

Vehicle damage is the most common cause of reactive maintenance in the LV distribution fleet. If this causes irreparable damage, the entire asset will be replaced.

Spares

We normally do not maintain spares for the LV distribution fleet as these are readily available. Where there is physical damage to the structure, we replace the entire unit.

Renew or dispose

We carry out LV distribution unit renewals following visual inspection or reactively.

Renewals forecasting

We use a Repex approach to forecast renewals. We use different expected lives depending on the enclosure. Our unit rates are based on the expected average cost.

Options analysis

Limited options are available for LV distribution unit renewals – they are generally like-for-like (with a modern equivalent) or replacement in a better location.

Disposal

LV distribution enclosures have no special disposal requirements. Metal parts are normally recycled and the plastic is disposed of.

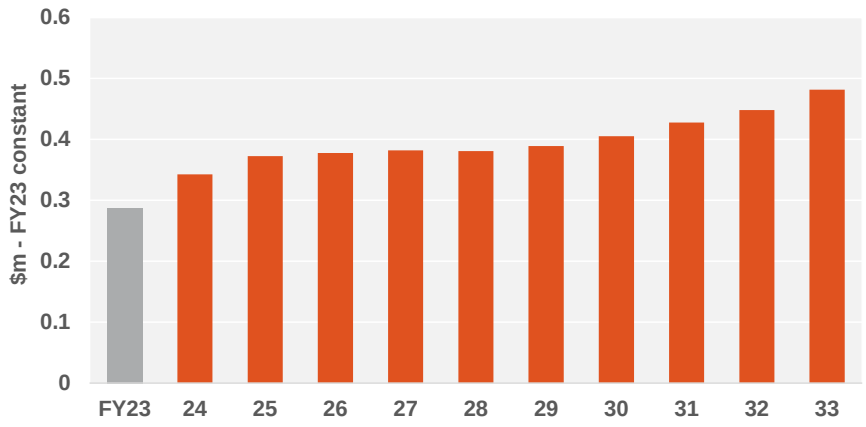
Coordination with other works

LV distribution assets can generally be replaced with minimal disruption to the network; therefore, there is a limited need to coordinate with other works.

LV distribution expenditure forecast

The expenditure forecast for the LV distribution switchgear is shown in the below graph.

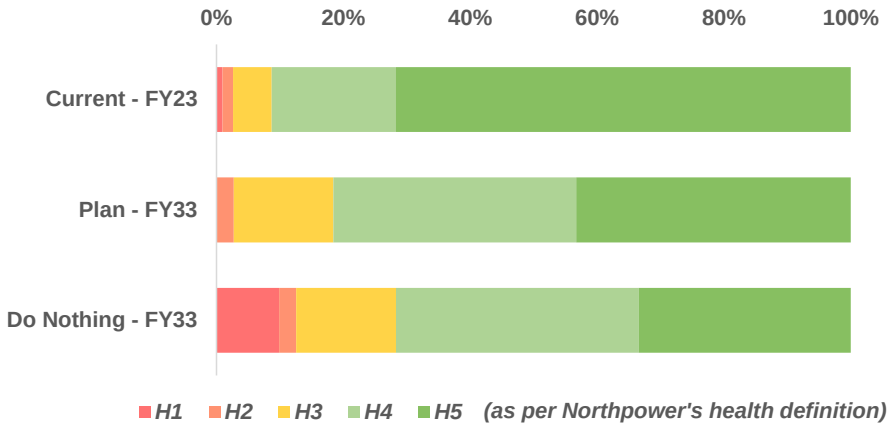
Figure 9.53: Forecast LV distribution unit Capex



Benefits

The key benefit of our planned renewal programme is reduced safety risk. The figure below compares the projected asset health in FY33 following our planned renewal programme, along with a counterfactual do nothing scenario.

Figure 9.54: Projected LV distribution unit asset health



Around 1% of our LV distribution unit fleet have been identified as being H1 and will require replacement over the next few years. If this programme of work was not undertaken, asset health would deteriorate, producing a substantially greater level of H1s by the end of FY33. This highlights the benefits of our planned asset replacements.

9.6.5. Pole-mounted switchgear

Pole-mounted switchgear fleet overview

Pole-mounted distribution switchgear consists of switching devices that are typically mounted on poles located on our distribution network and are at different voltage levels. The device can be used for isolation or both protection and isolation. The portfolio includes links, fuses, switches, reclosers, and sectionalisers.

Pole-mounted fuses protect and isolate distribution transformers and, in rural areas, provide fault isolation for tee-offs supplying low customer density spur lines or cables. HV fuses and links are installed in the overhead distribution network to isolate 11kV transformers and spur lines. Fuses provide short-circuit protection for the equipment or reticulation beyond.

For pole-mounted switches on our network, SF_6 is commonly used as the insulating medium. We still have a handful of air break switches, which we are gradually phasing out due to maintenance and safety concerns. Some of the pole-mounted switches can be operated either manually or remotely via SCADA. Pole-mounted switches are also used to assist with fault-finding on long rural networks. They are mainly operated during planned or unplanned outages to isolate a section of the network that has experienced a fault or shift customers onto alternate feeds and isolate a section of the network for planned outages.

Reclosers and sectionalisers are devices that increase reliability by reducing the area impacted by faults. A recloser is effectively a circuit breaker with protection and control functionality mounted on a pole. Its primary purpose is to isolate faults on a section of line without interrupting customers upstream of the recloser. The maximum number of reclose attempts is three and reclose attempts must occur within 60 seconds of the initial tripping.

Sectionalisers work in conjunction with an upstream recloser and requires coordination between the control settings in both the sectionaliser and recloser. The sectionaliser will detect a fault current passing through it and will wait for the upstream recloser to isolate the fault. The sectionaliser will then operate and disconnect the faulted section of the network, allowing the upstream recloser to re-energize the network up to the point of the sectionaliser. Sectionalisers allow us to minimise the impact of network faults by limiting the number of customers left offline.

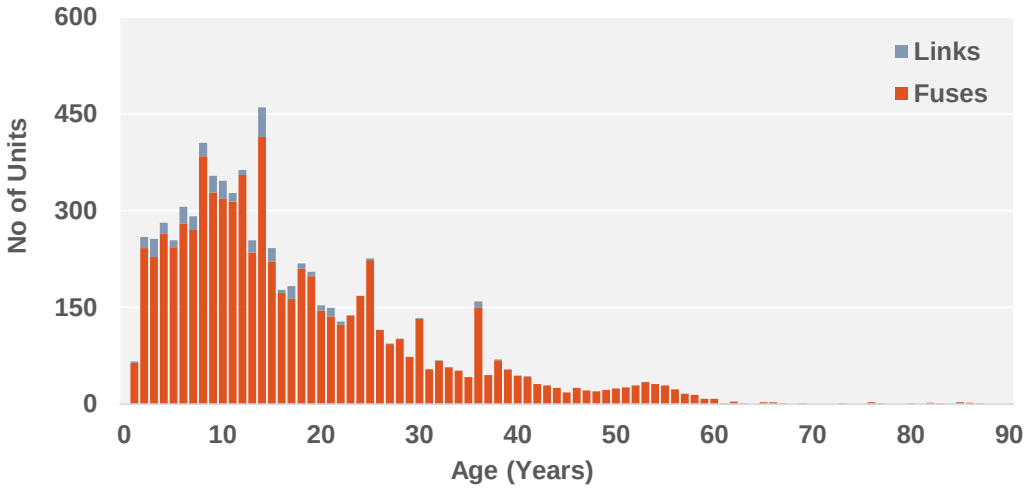
Population and age

We have nearly 8,600 pole-mounted switchgears units on the network.

Table 9.49: Pole-mounted switchgear population by type

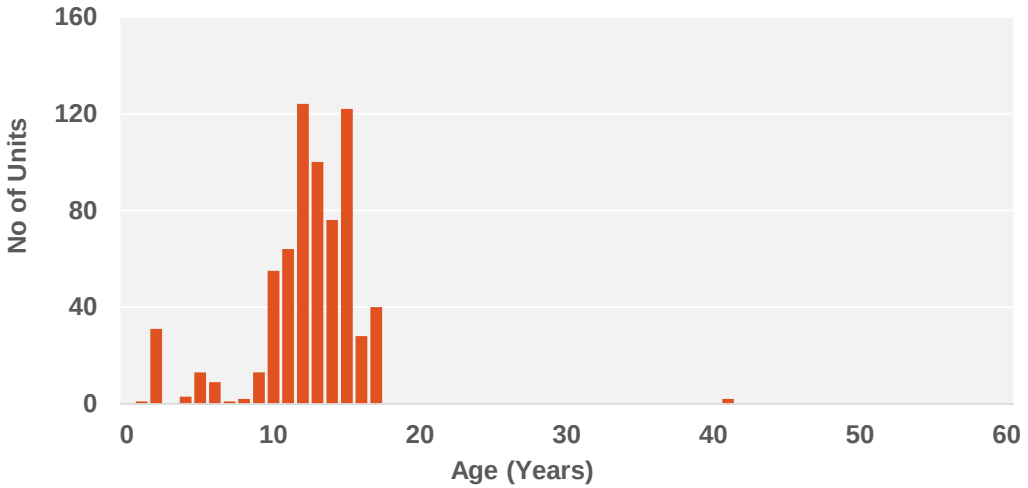
POLE-MOUNTED SWITCHGEAR	SUBTRANSMISSION	DISTRIBUTION	TOTAL
Links	8	381	**389**
Fuses	0	7,485	**7,485**
Overhead switches	15	669	**684**
Reclosers	2	31	**33**
Sectionalisers	0	1	**1**
Total	**25**	**8,566**	**8,591**

Figure 9.55: Links and fuses age profile



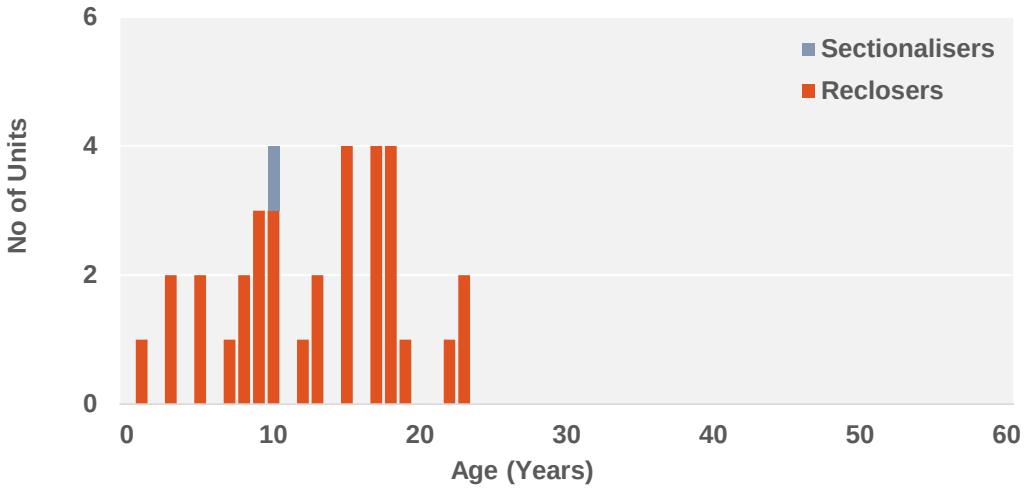
Compared to the average expected age for links and fuses, most of our pole-mounted links are near mid-life, while our pole-mounted fuses have a relatively young age profile. The average age of our links and fuses is 17 years (12 years and 18 years respectively).

Figure 9.56: Overhead switches age profile



The above graph illustrates the age distribution of overhead switches. Compared to the expected age of overhead switches, the majority of the units have passed mid-life. The average age of overhead switches is 12 years.

Figure 9.57: Reclosers and sectionalisers age profile



The above graph shows the age distribution of pole-mounted reclosers and sectionalisers. Compared to the expected age of reclosers and sectionalisers, the assets have a young age profile. The average age of our reclosers and sectionalisers is 13 years.

Condition, performance, and risks

Condition and performance

We do not undertake detailed condition assessment of fuses. Any failure or malfunctions normally result in replacement of fuse. Whenever a type defect, corrosion, or failure of an older models of fuse is detected, the whole fuse assembly, including mounts, is replaced with its modern equivalent.

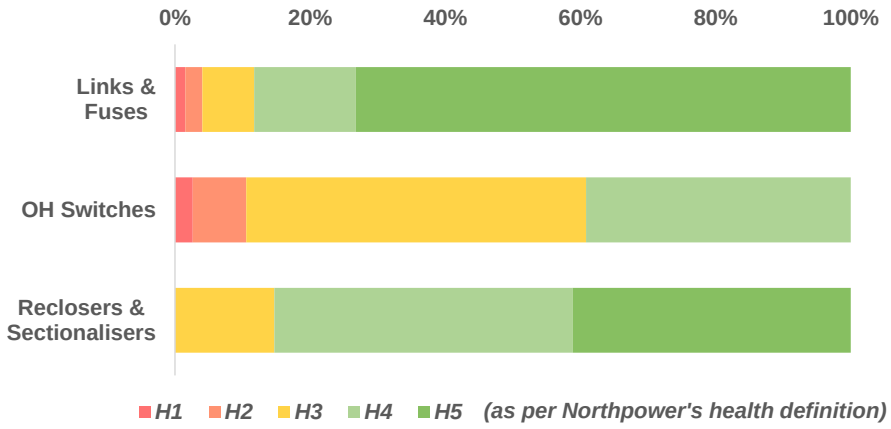
Pole-mounted fuses are in generally good condition. As with pole-mounted fuses, we do not undertake extensive maintenance programme and condition assessment of overhead switches. Instead, ones with maloperations or damage during operation are DNO tagged and repaired or replaced. There have been issues of corrosion with overhead switches, particularly ones near the coast. There have also been instances of water ingress within the switch operating mechanism, which has caused the moving parts to seize up.

The performance of the reclosers and sectionalisers in the network has been satisfactory. Older models have issues with their ability to clear faults, which extends restoration times. As these issues comes up, we plan to replace these with modern equivalents.

Asset health

AHI for the pole-mounted switchgear is based on expected remaining life.

Figure 9.58: Pole-mounted switchgear current asset health



Risks

The table below summarises the key risks identified in our pole mounted switchgear fleet.

Table 9.50: Pole-mounted switchgear population by type

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Condition based failures	Renewal programme	Network performance
SF_6 leaks	Inspection and maintenance Replacement programme	Network performance Environment and sustainability
Water ingress causing seizing up of moving parts	Inspection and maintenance Replacement programme	Network performance
Risk of vegetation fire when auto reclosers operate	Maintaining restrictions during seasons of fire risk	Safety Environment and sustainability

Design and build

Pole-mounted fuses are selected based on the network's specific protection and operational requirements. When a distribution line is renewed, we consider replacing fuses supplying spur lines with more effective devices, such as reclosers or sectionalisers. This improves network reliability and reduces outage downtime. Before a new type of fuse can be used on the network it is thoroughly assessed for suitability.

We use SF_6 switches in corrosion-prone areas instead of standard ABS switches. Although these switches are more expensive, they require less intrusive maintenance, can interrupt higher load currents than standard ABS, and can be made remotely operable. SF_6 switches are available in automation-ready configurations. The installation of automation-ready switches at critical interconnection points increases remote control operations.

Reclosers and sectionalisers are critical for maintaining network reliability and minimising disruptions. When new equipment enters the market, it is subjected to a thorough assessment to ensure it is fit for purpose. This includes construction material checks, such as stainless steel grades, which have proven critical in ensuring assets reach expected life.

Operate and maintain

Our pole-mounted switchgear fleet is inspected as part of our overhead line inspections, which look for damage, corrosion, and deterioration. Other key preventive maintenance activities like oil change, topping up of SF_6 gas, thermal imaging, and battery checks are carried out at set maintenance intervals.

Preventive maintenance

The preventive maintenance inspection task and frequencies are summarized below.

Table 9.51: Pole-mounted switchgear preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Aerial inspection of overhead switches and links including rapid inspections of subtransmission circuits and express lines, checking for key defects	Yearly
Visual inspection and back-up battery change of remote-controlled overhead switches, reclosers, and sectionalisers	Two yearly
Control battery change of remote-controlled reclosers and sectionalisers	Four yearly
Visual inspection of pole-mounted hardware as part of overhead network inspections, completing a detailed condition assessment	Five yearly
Recloser oil change and refurbishment	Eight yearly

Corrective maintenance

We generally do not undertake any corrective maintenance on fuses as they are replaced if issues are found. We only undertake simple corrective maintenance on pole-mounted switches, like fixing minor corrosion, alignment of contacts, etc. Recloser corrective maintenance includes adjusting settings outside of preventive maintenance due to network changes and resolving communication issues.

Reactive maintenance

Reactive maintenance includes the replacement of fuses when they clear faults. The most common recloser and sectionalisers defects are with either the controller or the communication system, with fewer failures occurring within the device itself. Depending on the nature of the fault, it may be repaired on site, or a spare may be used to replace defective parts. If the primary device fails, a unit swap is required.

Spares

We manage and maintain an inventory of spare pole-mounted fuses, switches, reclosers, and sectionalisers to ensure defects can be quickly cleared by swapping devices.

Renew or dispose

Pole-mounted fuse renewal is based on condition and known type issues. We replace pole-mounted fuses during routine inspections due to condition, obsolescence, and reactively following faults. Some models of expulsion drop-out fuses and link holders are susceptible to corrosion and reliability issues. These are usually replaced during related works.

Pole-mounted switches are mostly replaced due to poor condition. Switches with identified defects are scheduled for replacement as part of defect management. The replacement trigger for a recloser will normally be operation count. Whenever a recloser reaches its limit or is found to be significantly degraded or malfunctioning, replacement is planned as part of our defect management process.

Reclosers and sectionalisers are individually assessed for replacement based on age, condition, and any other known issues.

Renewals forecasting

We use a Repex methodology for the forecasting of pole mounted switchgear. We use different expected lives depending on the type of switchgear. Our unit rates are based on the expected average cost to replace each type of switchgear.

Options analysis

When pole-mounted switchgear is identified as being at end of life, we consider options such as like-for-like replacement, upgrade to switchgear with more functionality, relocation, and decommissioning.

Disposal

Pole-mounted switchgear has no specific disposal requirements. Metal parts such as copper or aluminium are recycled, and oil is disposed of responsibly.

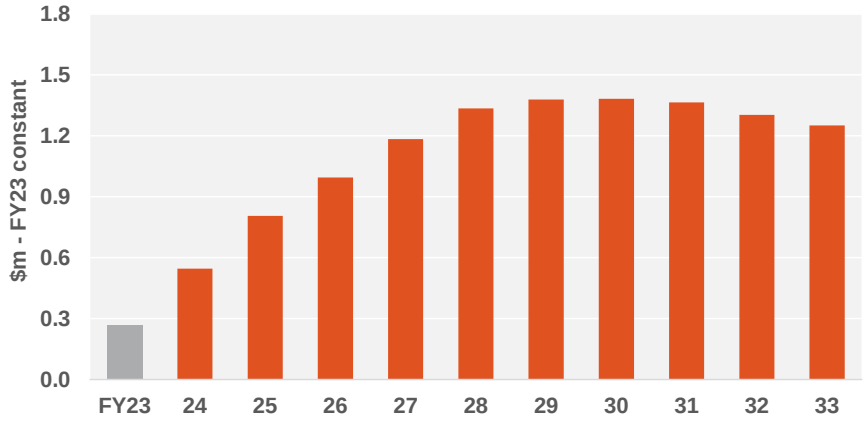
Coordination with other works

Renewal of pole-mounted switchgear is often coordinated with other replacement and maintenance work to ensure outage times are minimised. For efficiency, switchgear such as fuses can be replaced during pole or transformer replacement.

Pole-mounted switchgear expenditure forecast

We forecast $12.4 million of pole-mounted switchgear renewal during the planning period. Expenditure and replacement rates will gradually increase to a steady state level by FY28.

Figure 9.59: Forecast pole-mounted switchgear Capex



Benefits

The main benefit of our planned renewal programme is that it will ensure reliable network performance by eliminating operational issues and associated safety risks.

Figure 9.60: Projected links and fuses asset health

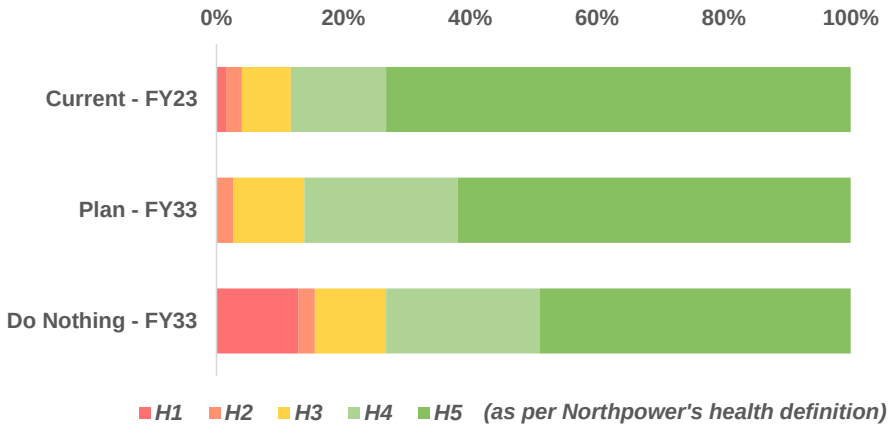


Figure 9.60 compares AHI in FY23 with projected AHI in FY33 following our programme of renewals, with a counterfactual do nothing scenario. If no investment were made, around 17% of our links and fuses assets would be end of life by FY33. Our investment programme reduces this to zero. This highlights the benefits of the replacement programme.

Figure 9.61: Projected overhead switches asset health

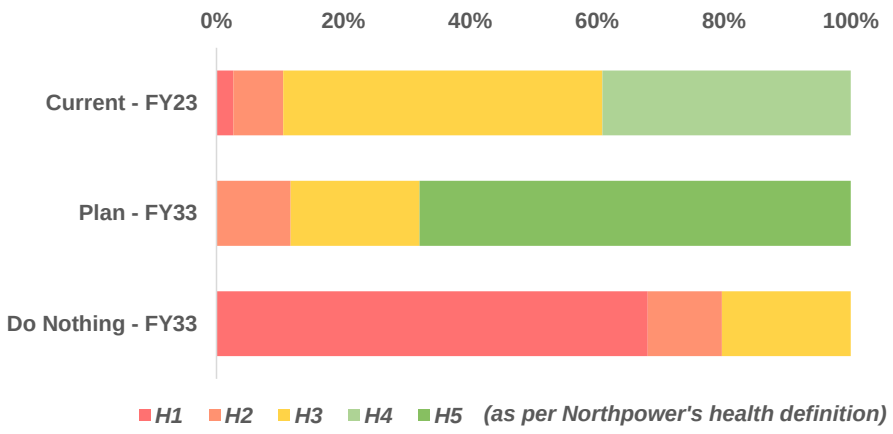


Figure 9.61 compares the AHI in FY23 with the projected AHI in FY33 following our programme of renewals, with a counterfactual do nothing scenario. If we undertook no replacements, we expect the proportion of H1 overhead switches to be approximately 62% by FY33, compared to no H1 assets under our proposed replacement programme.

Figure 9.62: Projected reclosers and sectionalisers asset health

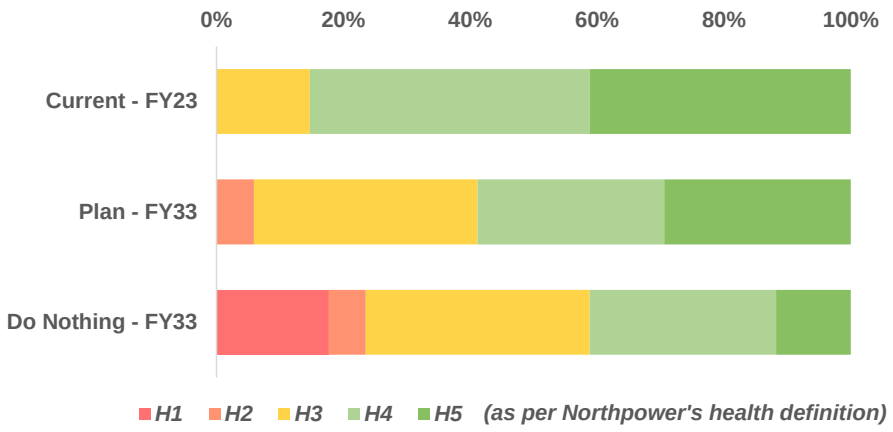


Figure 9.62 compares the AHI in FY23 with the projected AHI in FY33 following our programme of renewals, with a counterfactual do nothing scenario. Currently there are no assets in the H1 category. However, over the next 10 years we would expect to have 5% of assets in the H1 category if we made no investment.

9.7. Secondary systems and other assets

This section describes in detail the secondary systems portfolio, which includes eight asset fleets:

- protection systems
- automatic voltage regulators
- auxiliary power supply systems
- capacitor banks
- load control
- SCADA system
- automation and control systems
- communication.

This section provides an overview of these asset fleets, including their population, age, and condition. It explains our renewals, operational and maintenance approaches, and provides expenditure forecasts for the planning period.

Box 9.25: Portfolio summary

We plan to increase our investment to an average $1.8 million per year over the planning period. Our plan focuses on protection systems, replacing relays based on age and type. A significant proportion of our protection relays are becoming obsolete, which presents some safety and network performance risk to the network.

Secondary systems are crucial for the safe and reliable operation of our network, as they power and control primary equipment such as reclosers and circuit breakers. The portfolio includes assets that are generally relatively low cost; however, they have much shorter lives compared to the primary assets they power and control.

Protection systems detect network faults or abnormal power system conditions and operate equipment to isolate the faulted part from the rest of the system. This maintains system stability and prevents further harm to people and assets. Protection systems are typically located in our substations but also include field systems that operate our reclosers.

Communications, automation and control, and SCADA systems work together to provide remote visibility and control. They enable our operations team to manage the network in real time.

Auxiliary power systems provide reliable back-up power supplies to vital equipment in our substations. These systems typically comprise batteries and chargers that provide power to ensure continued operation of equipment after AC supply is lost to substations.

Capacitor banks are employed to manage the supply voltage on our network where long lines or large inductive loads exist. Load control systems are in place to switch off load (predominately hot water systems) and manage network constraints when necessary.

9.7.1. Portfolio objectives

Portfolio objectives are listed in the following table.

Table 9.52: Secondary systems and other assets objectives

OBJECTIVE AREA	PORTFOLIO OBJECTIVES
Safety	No injuries or fatalities resulting from protection maloperation[39] SCADA system always allows for reliable control and accurate visibility of the network
Network performance	No protection maloperation causing a loss of supply or that renders primary equipment unserviceable DC systems provide adequate carry-over time during AC loss of supply events
Supporting communities	Coordinate protection replacements with zone substation work where practicable to bring down project costs
Environment and sustainability	Dispose of lead acid batteries in a responsible manner
Capability	Trial the use of newer, smarter technology to understand its potential asset management, operational, safety, and customer benefits

9.7.2. Protection systems

Protection systems fleet overview

Protection systems are installed in substations to detect faults and operate circuit breakers to isolate faults. Protection systems must be able to discriminate between faults occurring in other locations versus faults on parts they are deployed to protect. This minimises the network outage footprint and improves fault clearance times. Protection systems typically consist of relays, test blocks, switches, wiring, panels, communication interfaces, and junction boxes. Protection relays have evolved over time but can be described as two main technologies: numerical, electromechanical, and static relays.

Electromechanical and static relays

Electromechanical and static relays are legacy technologies. While they have provided many years of reliable protection, they are now mostly obsolete. Electromechanical relays, as their name suggests, comprise electromagnets and coils driving mechanical components such as rotating discs, to operate and relay signals under specific conditions. In contrast to electromechanical relays, static relays do not contain any moving parts, instead relying on analogue electronics to create the same relay functionality. Both technologies are relatively basic in design, where each relay provides a specific protection functionality. We would typically need multiple relays of these types to provide the protection we need. For example, we may need up to three electromechanical relays to provide line differential protection, but we may need only one modern numerical relay for this protection function. These types of relays also lack the flexibility in configuration, self-monitoring capabilities, and functionality of more modern protection technologies. Spare parts for most

[39] Protection maloperation happens when the protection system fails to clear a fault due to a software or hardware fault. This does not include issues due to incorrectly applied settings or discrimination issues.

of our electromechanical and static relays can no longer be sourced, and repair is challenging and typically not economic.

Numerical relays

Numerical relays use modern digital technology and are programmable, making them extremely flexible in their application and configuration. Numerical relays have multiple analogue or digital inputs and relay outputs available. They are also able to integrate directly with SCADA, can enable remote engineering access, and store real-time and historical data for fault analysis.

These relays also have self-monitoring capabilities, allowing component failure to be reported back to SCADA. Network operators can send technicians to rectify the issue.

Numerical relays are now the preferred protection relay technology for the electricity industry. However, numerical protection requires familiarity with digital/computer coding. This requires continuous upskilling of our staff, particularly our service technicians and protection engineers, to keep up to date when new protocols and firmware updates are rolled out. In addition, we also need to keep our settings configuration software up to date with manufacturer releases.

Population and age

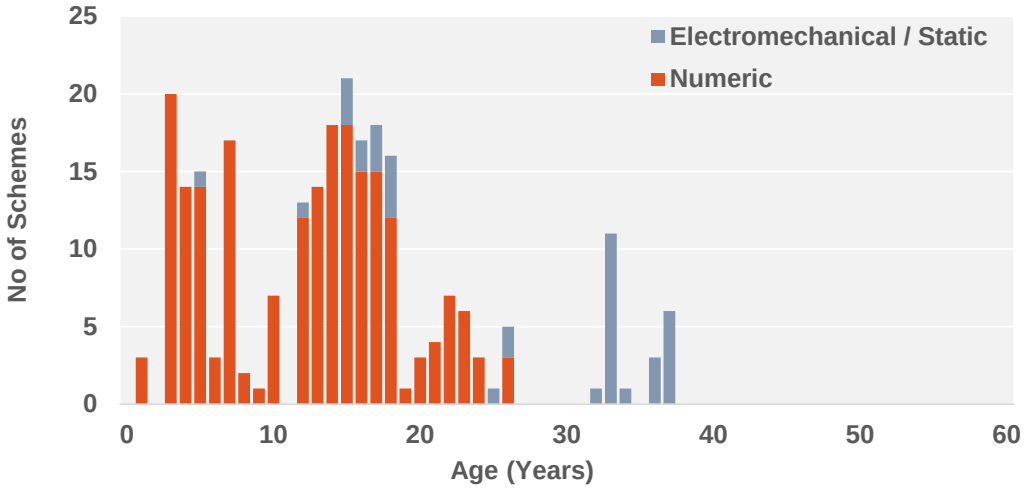
The table below summarises our population of protection schemes by function and relay type. Each protection scheme comprises one or more relays. We count schemes because a modern equivalent scheme may comprise fewer relays than the schemes it is replacing

Table 9.53: Protection function and relay types (number of schemes / number of relays)

FUNCTION	ELECTROMECHANICAL & STATIC	NUMERICAL	TOTAL
Arc flash		4 / 4	4 / 4
AUFLS	11 / 13	1 / 1	12 / 14
Bus coupler	1 / 1	6 / 6	7 / 7
Bus zone	3 / 29	2 / 3	5 / 32
Feeder	10 / 26	120 / 123	130 / 149
Subtransmission	5 / 7	47 / 54	52 / 61
Transformer	13 / 55	32 / 62	45 / 117
Total	**43 / 131**	**212 / 253**	**255 / 384**

Protection is generally named for the primary plant the relays are protecting, with the exception of arc flash and automatic under frequency load shedding (AUFLS) protection. Arc flash relays primarily use light detection, alongside current measurements, to sense an arc in indoor switchgear. It can quickly isolate the supplies to the switchboard to limit arcing, which reduces equipment damage and potential harm to personnel. AUFLS is a special type of protection that maintains system stability by shedding load automatically when an under-frequency event is detected.

Figure 9.63: Protection systems age profile



We have replaced many of our electromechanical and static relays with numerical types over the last 20 years. Schemes are replaced when they become obsolete, i.e. are no longer supported by the manufacturer or when there is lack of spares. The expected life of electromechanical and static schemes is 40 years, and 20 years for numerical schemes.

The average age of our relays is 18 years (12 years for numeric and 28 years for electromechanical/static). Some of our first-generation numerical schemes have now reached or exceeded their 20-year life. Many of our electromechanical schemes will reach their expected life by the end of the planning period. We will phase these out and replace them with numerical schemes.

Condition, performance, and risks

Condition and performance

Our electromechanical relay fleet has a proven record of good performance. However, as these relays near their expected life of 40 years, the mechanical parts become overly worn, allowing the relay calibration to drift. This drift may cause the relay to operate incorrectly or fail to clear a fault quickly. To mitigate this, we calibrate them during scheduled maintenance and replace parts. Another issue is that spares and parts for electromechanical relays are becoming more difficult to source as several types are no longer manufactured.

Our numerical relay fleet has had relatively good performance; however, we have previously deployed fast bus blocking (FBB) schemes that use a specific type of numerical relay which is unreliable and is now obsolete. FBB schemes are a relatively simplistic form of bus zone protection, which utilises feeder and transformer relays connected in series. FBB protection is relatively cost-effective to install; however, if one of the relays is temporarily removed from service for maintenance, this disables the scheme and poses safety risks to our staff working in the area. These relays are also relatively old, with most nearing the 20-year expected life.

We have observed several protection discrimination issues. These occur when protection systems do not act in a coordinated manner – either tripping load unnecessarily, or not selectively clearing the fault using the device installed immediately upstream of that fault.

Most of these instances happen because settings are applied incorrectly or have become out of date (as the network load grows, settings need to be updated, otherwise it will inadvertently trip that load). We are exploring options to more tightly control our protection settings and avoid these incidents.

Risks

The following table sets out the key risks and mitigations we have identified for our protection systems.

Table 9.54: Protection system risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Protection relay fails to detect and isolate faults correctly	Settings are reviewed regularly and any gaps identified are quickly addressed Replacement programme Implementation of local or remote backup protection	Safety Network performance
Obsolete relays fail with no spares available, resulting in prolonged equipment outage.	Contingency plan enacted to replace relay with a different model Replacement programme Spares purchased where available	Safety Network performance
Cybersecurity breach resulting in unnecessary tripping or equipment damage	Install firewalls where appropriate and ensure firmware updates are regularly applied Access restrictions to network control	Safety Network performance
Complicated scheme implementation, resulting in extended outages during fault-finding and analysis	Technicians and staff are regularly trained and competent Standard network protection philosophy and protection arrangements	Network performance

Design and build

The main objective for our protection system design is to correctly identify faults and isolate them effectively. This requires balancing several competing requirements such as:

- coordination with other protection in the immediate area in terms of primary plant coverage, clearance speed, and sensitivity
- stability of the protection equipment and ability to operate normally during power swings or current reversals
- availability and accuracy of CT cores could drive the type of scheme implemented, i.e. differential bus zone versus bus coupler overcurrent protection
- simplicity of the protection scheme – the simpler it is, the easier it is to maintain and undertake fault analysis; however, this may sacrifice discrimination capability
- lifecycle cost, as the goal is to select a scheme type that addresses network safety and reliability risk, consistently balanced with being cost-effective
- availability of local or remote backup protection, consistent with our protection philosophy that addresses our network risk
- applying remote engineering access (REA), particularly for remote / difficult to access areas of our network. However, REA requires new infrastructure to be developed, and its cost-effectiveness will need to be made on a case-by-case basis.

We have recently completed our protection philosophy document. This is a key document which will drive consistency and standardisation of our protection scheme designs going forward.

Simple protection design, such as ad hoc feeder protection replacements, are typically completed by our in-house team and the installation works carried out by our contracting division. Larger, more complicated projects such as bus zone protection, are generally outsourced for design. Installation is carried out by our contracting division.

Operate and maintain

Preventive maintenance

We regularly inspect, test, and maintain our protection assets to ensure they operate reliably. Our electromechanical relays require frequent calibration and detailed inspections and testing compared to numerical relays. Numerical relays, though more complicated, can self-diagnose performance with interval-based inspections covering any other gaps. Our approach is summarised below.

Table 9.55: Protection systems preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Visual inspection of relays as part of zone substation equipment inspection	Two monthly
Detailed condition assessment and operational checks for electromechanical and static relays	Two yearly
Detailed condition assessment and operational checks for numerical relays	Four yearly

Corrective maintenance

Corrective maintenance on protection systems is limited to component replacements and changes necessary to relay settings that arise from protection review or fault analysis.

Reactive maintenance

We undertake reactive maintenance on protection systems in response to callouts for alarms, gather data from relays for fault analysis, and respond to relays that fail in service.

Renew or dispose

Protection renewals are guided by the following principles.

- **Safety**: protection schemes are critical in detecting and isolating faults. Maloperation poses a significant safety risk to our personnel and the public. We have also identified a specific type of relay (FBB schemes) that has a safety vulnerability.
- **Obsolescence**: relays that are no longer supported and have limited spares available pose a risk to reliable network supply. Our protection technicians are also finding it difficult to sustain the skills and software necessary to maintain these relays.
- **Functionality**: modern numerical relays provide significant functionality that enables us to carry out fault analysis in a more efficient manner, provide greater fault discrimination, and better control and operation of the network.

Our protection philosophy and subsequent gap analysis of our protection system against our design guidelines and philosophy, set out several recommendations:

- Replace FBB schemes.
- Review inadequate transformer protection settings, i.e. LV overcurrent protection resulting in longer than necessary bus fault clearance times. This could introduce or increase arc flash hazards on site.
- Install CBs and RMUs and associated protection on buses and long feeders.
- Review supply loss and safety risk at areas where we lack local backup protection and we rely on remote protection. This reliance increases fault clearance times (safety risk) and can result in a wider than necessary outage footprint.

These recommendations are currently being addressed. Our renewal programme will progressively replace FBB schemes when they become due for replacement. Some of our major zone substation projects, both renewal and growth, will directly address some of these recommendations and are included in their respective portfolios.

Box 9.26: Meeting our portfolio objectives – public safety and network reliability

As we progressively renew and replace our protection relays, the system as a whole, will become more reliable. This will minimise our safety and reliability risk due to decreasing risk of protection maloperation and hardware failure.

Table 9.56: Summary of protection systems renewals approach

ASPECT	APPROACH USED
Renewal trigger	Obsolescence, age (versus expected life)
Forecasting approach	Obsolescence (age/type based)
Cost estimation	Volumetric

Renewals forecasting

We forecast renewals based on our strategy to replace all relays that are obsolete or have reached end of life. We size our programme to be consistent with resource constraints.

Options analysis

Options for replacing protection schemes include lifting protection discrimination capability, such as applying differential protection rather than simple overcurrent. Another consideration is the application of inter-trips for interconnected areas where faults can be fed from multiple sources. Combinations of different types of schemes are considered on a network basis.

Disposal

Relays and associated parts that can be re-used are retained and kept as spares. Disposal requirements for relays are similar to other electronic devices. Where mercury is present (typically sourced from old Buchholz relays), it will be disposed of in an appropriate manner.

Coordination with other works

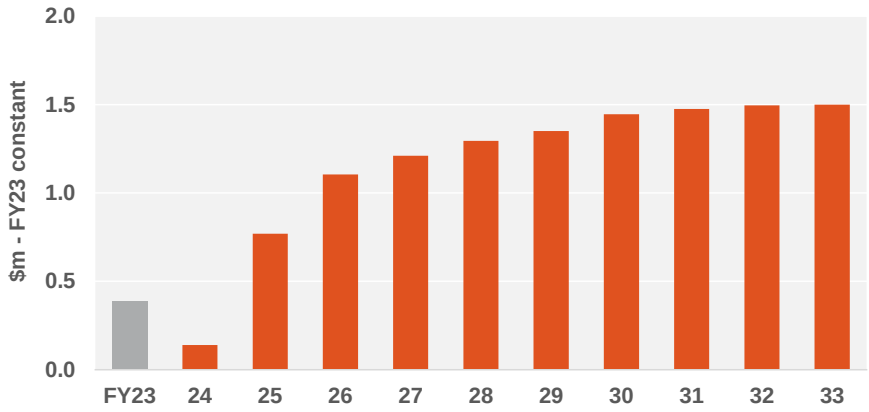
Protection systems projects are coordinated with substation projects, whether they are growth or renewal projects. This practice will reduce overall costs and equipment downtime.

Protection systems expenditure forecast

We forecast renewals using a volumetric approach. Unit rates vary by scheme type, with bus zone differential and arc flash protection having higher unit costs compared to others.

We plan standalone protection renewal Capex of $11.8 million over the forecast period.

Figure 9.64: Forecast protection systems Capex



We plan to lift our delivery capability in the protection space progressively over the next few years, and to replace all end-of-life protection by FY33.

Benefits

The key benefits of our renewal programme are mitigating in-service relay failures, minimising maloperation risk, and increasing protection functionality. This allows us to better manage the network and resolve faults more quickly.

9.7.3. Automatic voltage regulators (tap changer controls)

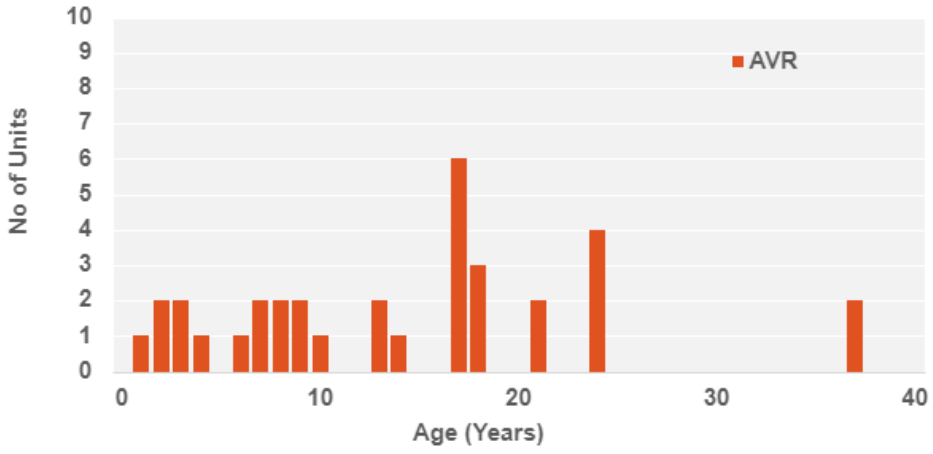
Automatic voltage regulator fleet overview

Automatic voltage regulators (AVRs) are electronic devices used to maintain a constant voltage output from a power source, such as a generator or transformer. A tap changer controller is a type of AVR that regulates the voltage by adjusting the tap setting on the transformer. These are essential in power distribution systems as they ensure the voltage output remains stable, preventing damage to equipment and ensuring reliable performance.

Population and age

The following chart shows the fleet of tap changer controllers in our network. We have 38 controllers, with service life ranging from new to 37 years in service.

Figure 9.65: Age profile of AVR fleet



Condition, performance, and risks

Condition and performance

Our AVRs have generally performed well in the past and the condition of the fleet is reasonable. We have two older units in service which have had reliability concerns. We plan to replace these over the next few years during larger substation projects.

Risks

The AVR is critical to the proper functioning of our network, ensuring we meet our power quality obligations. Therefore, failure risk needs to be effectively managed.

Table 9.57: Risks associated with AVR fleet

ISSUE	RISK MITIGATION	MAIN RISK
Failure of AVR leading to inadequate voltage control	Periodic inspection Maintain spares inventory	Network performance

Operate and maintain

Preventive maintenance

We have recently included a four-yearly maintenance task as part of the routine inspection of AVRs. Settings and functionality are checked as part of this task.

Table 9.58: AVR preventive maintenance tasks

TAP CHANGER CONTROLLER	FREQUENCY
Routine equipment inspections and checks	Four yearly

Corrective maintenance

The manufacturer recommends replacing the battery every six or 10 years based on duty cycle. When this task is performed it is standard practice to back up the parameters in use.

Over time, the equipment may require software updates or upgrades which are also carried out under corrective maintenance.

Reactive maintenance

Reactive maintenance is carried out in response to unexpected equipment failure. This may require emergency replacement of the AVRs or other associated equipment. We maintain a spare unit of our preferred controller to have available if there is a failure.

Design and build

There are many types of voltage regulators on the market. Our standard design is now an Eberle Reg-D tap changer controller. This ensures that we can keep our spares holdings down and minimise the range of controllers our technicians need to be familiar with.

Renew or dispose

We generally replace our AVRs based on age or obsolescence. We try to align these replacements with our transformer and transformer relay replacements.

Options analysis

There are minimal options available when replacing our tap changer controllers. We generally replace them with a modern equivalent.

Dispose

Material disposal is done separately when disassembly is possible, considering metals and plastics as recyclables while treating disposed electronic circuits as electronic waste.

Automatic voltage regulators expenditure forecast

We do not currently have a standalone forecast for AVRs. This Capex is combined with transformer or transformer protection replacements.

9.7.4. Auxiliary power supply systems

Auxiliary power supply systems fleet overview

The auxiliary power supply systems provide secure and reliable DC power to essential equipment in our substations and communication sites. Protection relays, circuit breakers control, emergency lighting, and radio are supplied from DC power systems to ensure the operation of these devices during and after a fault, when AC power is expected to be lost.

The two main components of auxiliary power systems are the battery bank and the battery charger. The voltage is based on the purpose of the DC supply. Protection systems are normally supplied at 110V, and communication sites are supplied at 48V.

To achieve 110V systems, the banks usually consist of nine 12V batteries. We also have two substations in which 54 2V batteries are connected to form an 110V battery bank. Currently, sealed lead acid batteries are the most common type of battery and our preferred option when replacing old units.

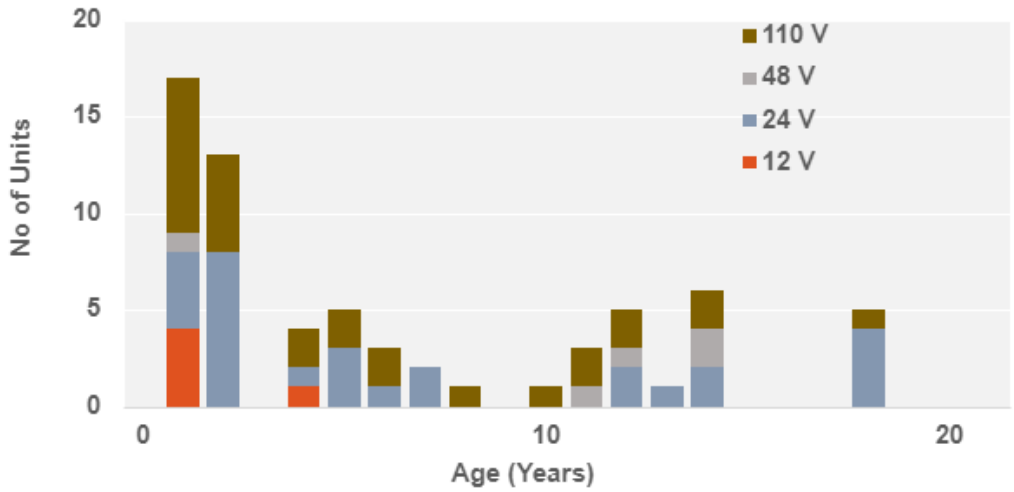
Population and age

The table below shows our auxiliary power fleet by system purpose and battery voltage.

Table 9.59: Auxiliary power system fleet

SYSTEM PURPOSE	VOLTAGE	BATTERY BANKS
Protection systems	110 V	28
Telecommunications fibre	48 V	20
Telecommunications radio	12 V	8
SCADA	24 V	27
Total		**83**

Figure 9.66: Auxiliary systems age profile



We have battery banks which are beyond their 10-year life expectancy. We plan to address these battery banks over the planning period.

Condition, performance, and risks

Condition and performance

Our battery banks are in reasonable condition; however, some have exceeded their expected life. We believe the risk of failure with these banks is low in the short term as periodic checks are carried out on battery banks. Cells found to be in poor condition are replaced.

Asset health and criticality

We will address end-of-life drivers in the battery banks targeted for replacement over the AMP period. Auxiliary systems are critical to ensure reliable and safe network performance, and we prioritise these for intervention.

Risks

We have identified two main risks related to auxiliary power systems:

- auxiliary system failing in service
- catastrophic battery failure.

Both these risks impact safety and reliability. To mitigate them, we have developed inspection and testing of in-service systems. We also replace batteries based on age.

Design and build

The capacity required from each individual battery bank is site specific and designed to industry standards. A single tripping and re-closing operation of all circuit breakers plus all standing loads are used to determine the substation total load (continuous and momentary) for a set standby period and number of operations. The main factors are the load connected to it and the time the auxiliary power system is expected to supply the load if AC power is lost. This is called 'carry-over time', and it is a function of load and response time.

Operate and maintain

Preventive maintenance

Auxiliary power systems are critical assets. As such, they are regularly inspected and tested. The table below shows our preventative activities and frequency.

Table 9.60: Auxiliary power supply system preventive maintenance tasks

MAINTENANCE AND INSPECTION TASK	FREQUENCY
Zone substation battery inspection and test	Two monthly

Corrective maintenance

After a battery cell is diagnosed as defective, it is immediately replaced. Diagnosis occurs during testing or routine inspection.

Renew or dispose

There is a replacement programme for battery banks. Renewal is age based but can also be condition driven, because of routine inspections conducted as part of the preventive maintenance of the auxiliary power systems. Where cost-effective battery upgrades are aligned with major primary plant upgrades. This ensures new load designs are correctly scaled and the overall installation are to the same standard.

Of our 68 battery banks, 17 of them have surpassed their 10-year life expectancy. We plan to steadily replace our fleet over the long term, to maintain it appropriate life expectancy.

Options analysis

We are aiming to standardise battery banks and chargers. This will improve the way we handle spare batteries and chargers. Mounting racks, electrical connections, and communication cables may also be standardised.

Replacements will be coordinated with other projects planned at the substations. However, given how critical auxiliary power systems are, their requirement will have higher priority.

Disposal

When a battery is depleted, is to be disposed of and delivered for recycling. Until then we store it in a covered area within a spill tray to catch any leaks. Old batteries are transported, carefully and transported within a suitably sized spill tray.

Auxiliary power supply systems forecast expenditure

Over the planning period we plan to spend approximately $50k per annum on battery bank replacements. This is to cover targeted replacements and corrective replacements following preventive maintenance checks.

9.7.5. Capacitor banks

Capacitor banks fleet overview

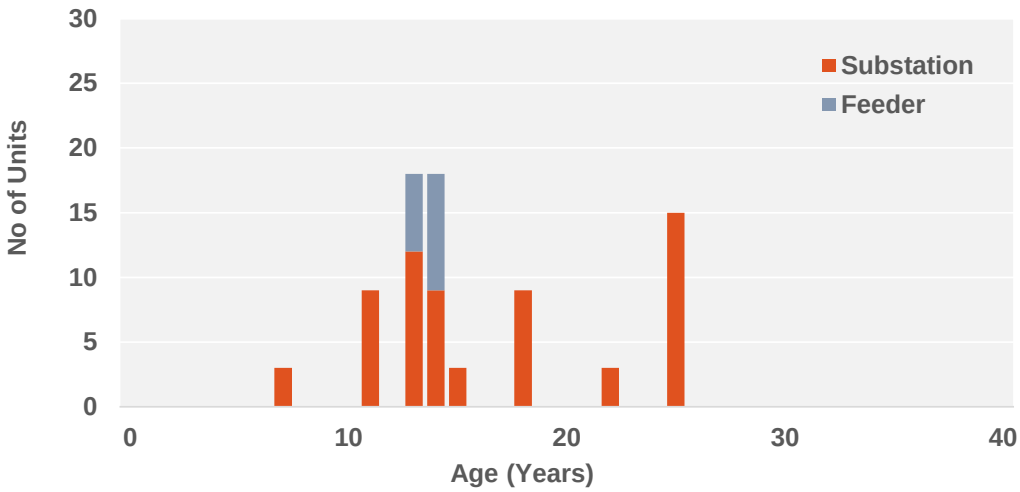
Capacitor banks are used to counteract large inductive loads, improving the power factor, network voltage levels and current transfer capacity. Inductive loads are usually large motors; however, transmission circuits also contribute to the inductive load on the network.

In our network, 750kVAr capacitor banks are installed in some of our substations. We also have 150 or 200kVAr capacitors installed on 11kV feeders that have large inductive loads.

Population and age

Our capacitor fleet age is shown as two groups: in substations and on distribution feeders.

Figure 9.67: Capacitor banks age profile



In total we have 26 capacitors installed in substations and 78 capacitors on our distribution feeder network.

Condition, performance, and risks

Condition and performance

Condition assessments indicate capacitor banks are all in satisfactory condition. To address failure risk due to an ageing fleet, age-based replacement will be carried out. The current age profile means no replacements are needed for the next 10 years.

Asset health and criticality

At this point, the asset health of our fleet is good and there are no end-of-life drivers.

Risks

Capacitors ensure our system voltage and supply voltages are within allowable limits. The table below summarises the key risks identified in our capacitor fleet.

Table 9.61: Capacitor bank risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Condition based failures of equipment	Renewal programme	Network performance
Stored energy	Appropriately discharge before work	Safety
Explosive failure	Renewal programme	Network performance

Design and build

Capacitor banks are typically installed on poles and usually constructed using three single phase capacitors. They are configured in an ungrounded star connection. Each capacitor is protected by an HV dropout fuse, and the overall switching of the bank is performed by a 3-phase overhead switch. When located in a substation and directly connected to a circuit breaker as a standalone, no fusing is required. To protect the banks from lightning strikes, surge arrestors are installed on the incoming line connection of each capacitor. Capacitors are filled with a dielectric fluid, with porcelain bushings hermetically sealed to the capacitor tank. We need to have appropriate corrosion protection in place to avoid breaking this seal.

Operate and maintain

Preventive maintenance

Our capacitor bank preventive maintenance programme is shown in the below table.

Table 9.62: Capacitor bank preventive maintenance

PREVENTATIVE MAINTENANCE	FREQUENCY	SCOPE OF WORK
Pole-mounted/substation capacitor banks	Five yearly	Visual inspection

Corrective maintenance

Typical corrective maintenance activities include cleaning of bushings or repair of overheated joints. We replace capacitors with dielectric leaks or corrosion that cannot be repaired.

Reactive maintenance

Failed capacitors are replaced as soon as possible.

Renew or dispose

Capacitors are scheduled for replacement based on age.

Options analysis

Typical options considered when a capacitor is found to be at end of life include:

- like-for-like replacement
- decommissioning
- replacement with a different type of reactive power support.

Disposal

We dispose of capacitors once they have reached the end of their useful life.

Capacitor banks forecast expenditure

Over the AMP period we have forecast $52k of expenditure in this fleet.

9.7.6. Load control

Load control fleet overview

We use ripple plants to help control load. These plants generate and transmit a signal across the network which is picked up by ripple control relays to undertake programmed actions. These signals are sent based on specific timetables or in response to events. Our network uses the Decabit ripple protocol type, which is considered reliable, secure, and fast. The load control signalling is used to manage the following:

- under-frequency load shedding
- hot water cylinders
- streetlights
- day/night metering
- tsunami warning siren activation.

We have six load control plants as set out below.

Table 9.63: Load control relays

RIPPLE PLANT LOCATION	INJECTION VOLTAGE	TRANSMITTER RATINGS
Maungatapere	33kV	200kVA
Tikipunga	33kV	200kVA
Maungaturoto	33kV	80kVA
Dargaville	11kV	40kVA
Bream Bay	11kV	40kVA
Ruakākā	11kV	40kVA

The main components of the system are the transmitter, the coupling cell, and the receiver.

Population and age

Our fleet is ageing, and action is needed in the medium term to control the associated risks.

Table 9.64: Load control relays ages

LOAD CONTROL PLANT (SFC)	AGE (YEARS)
Maungatapere	15
Tikipunga	19
Maungaturoto	12
Dargaville	5
Bream Bay	15
Ruakākā	13

Condition, performance, and risks

Condition and performance

Condition assessments indicate ripple plants are all in satisfactory condition. To prevent the increase of risk due to an ageing fleet, an age and condition based replacement approach is being carried out. The performance of this fleet has been satisfactory in the past, with some corrective maintenance required.

Asset health and criticality

Some of our ripple plants have been targeted for replacement to prevent an increase in risk.

Risks

The main risk is failure to manage load, leading to manual load shedding of feeders.

Design and build

The ripple plant consists of a number of individual assets. The individual asset types are:

- transmitter
- isolating transformer
- tuning coils
- capacitors

The installation is modular and individual assets can be replaced as needed. The equipment is typically robust, with similar life expectancies. We replace the unit or system at end-of-life.

The current approach is to replace the old transmitter with up to date IGBT power electronics. Additionally, current models offer a range of additional features supporting fault logging as well as output current and voltage reading.

Operate and maintain

Preventive maintenance

Load control plants are inspected and tested by specialist contractors, as described below.

Table 9.65: Load control preventive maintenance

LOAD CONTROL PLANT	FREQUENCY	SCOPE OF WORK
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks
Equipment test	Annual	Check operation and signal strength

Corrective maintenance

We have a contract with specialist contractors who repair components as required.

Reactive maintenance

We have a backup contract with specialist contractors who hold key spare parts.

Renew or dispose

We plan replacements based on age and condition of the asset.

Options analysis

When ripple controlled units are identified as being at end of life, they are replaced with a modern equivalent. No other options are currently considered.

Disposal

Depending on type of material, each component in the system needs a different treatment and is disposed of responsibly.

9.7.7. SCADA system

SCADA system overview

Supervisory control and data acquisition (SCADA) assets provide network visibility and remote-control operations. It allows our network operators to efficiently manage our network.

Northpower implemented a new GE PowerOn advanced distribution management system (ADMS) in 2020.

Table 9.66: Modules and subsystems description

MODULES/SUB SYSTEMS AND DESCRIPTIONS
SCADA
At the heart of our ADMS is a SCADA system which provides a real-time view of tele controlled parts of the network, including switch position and energisation, loading and voltage levels, and event logs. This is dynamically generated using graphical displays of network schematics combined with active tables and charts. The core SCADA system comprises: – remote terminal units (RTUs) – field devices concentrating sensor/actuator information (refer to automation and control section) – communications network – provides the link between the field and central server, comprising fibre, radio links and associated switching facilities (refer to communications section) – servers – the system runs four real-time application nodes across our head office and disaster recovery sites, providing a very high level of redundancy – SCADA workstations – provides the human machine interface (HMI). The system is a bespoke design. It was implemented with cybersecurity in mind, minimising the likelihood of any potential security breach. Redundancy is another core design principal, with all parts of the system allowing for failures without impacting operations.
Load management system (LMS)
The Catapult on-demand load control subsystems automatically control interruptible load on the network. This system interfaces with Transpower's energy markets, curtailing load when transmission is becoming a constraint and ensuring minimum disruptions for our consumers.
Distribution management system (DMS)
The SCADA system has been integrated with GIS and extended to include non-remote-controlled parts of the network. This enables us to digitise the supporting processes, including our 11kV wall mimic and access permits. We can simulate outage impacts, and the system prevents unsafe operation of the network, reducing the possibility of switching related incidents.
Network access request system
A new electronic network access permit system improves permit planning processes reducing disruptions
Outage management system (OMS) and advanced applications
A planned new OMS will help automatically identify fault causes and improve communications between our systems, staff, and customers.

Population and age

As mentioned earlier, our entire SCADA system has recently been replaced and is therefore relatively young (approximately two years old).

Condition, performance, and risks

Condition and performance

The ADMS is new and is therefore in relatively good condition. Implementation is ongoing and is being upgraded and patched regularly. Design and implementation has been carried out with high availability and cybersecurity as key architectural principals.

Asset criticality

The SCADA system is important to support safe day to day operation of the network.

Risks

The following risks have been identified through

Table 9.67: SCADA System risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Loss of visibility and control	Diverse communication paths Manual operation Preventive maintenance	Network performance
Cyber-attack resulting in third-party gaining control	Cybersecurity preventive measures Preventive maintenance (patching software)	Network performance

Design and build

GE's ADMS is quickly becoming the de facto standard, being used by many of the largest EDBs in New Zealand. We have used the New Zealand EDB model, which includes standardised symbology and configuration.

Operate and maintain

Our new ADMS system is kept patched and cyber secure, with regular updates provided by the vendors. The ADMS comes with higher ongoing overheads than the legacy SCADA system. This reflects the improved operations capability and the need to keep the system well maintained and cyber secure. Other older subsystems are monitored, vendor support contracts are in place, and systems are flagged for replacement when necessary.

Preventive maintenance

Our control systems and digital teams actively monitor, upgrade, and patch ADMS software as required. Application, DB, and OS critical security updates are applied soon after release.

Corrective maintenance

Our control systems and digital teams manage corrective issues – that is, problems raised by our NOC – based on priority.

Reactive maintenance

High availability provides redundancy for any hardware failures. Vendor support contracts are in place for hardware, and issues are dealt with as they arise.

Renew or dispose

Vendor certification drives decisions regarding our ability to patch or upgrade versus the need to replace or re-implement. Our objective for SCADA systems and hardware is to keep it patched and upgraded to support cybersecurity and extend the lifetime of the solution.

Replacement or upgrade of hardware will be considered mid-planning period, as it falls out of support. With regular patching and upgrades, replacement of the ADMS software and supporting subsystems should not need to be considered over the AMP period.

Options analysis

A complete replacement/re-implementation of SCADA systems is significant. This would see options analysis and project decision papers being escalated for consideration.

Disposal

Hardware is securely disposed of by our digital team.

9.7.8. Automation and control systems

Automation and control systems fleet overview

Remote terminal unit (RTUs)

Our network is accessible through SCADA system, which allows for remote control. It provides connectivity to the major communication sites and zone substations, and distribution assets such as voltage regulators and pole- and ground-mounted switches. RTUs are an essential part of our SCADA and telemetry system. In the zone substation, RTUs communicate with intelligent electronic devices (IEDs). A central master station communicates with RTUs via radio, microwave, and fibre optic cable.

Population and age

We have around 28 RTUs in the network. We do not have complete information on the age of these assets. A data capture exercise is underway, to address the data gaps.

Condition, performance, and risks

Condition and performance

RTUs are electronic devices, so obtaining accurate condition information is not practical. We instead use age as a proxy for health. Replacements are influenced by other factors e.g., functionality, obsolescence, and supportability. We manage the risk of unplanned failures through spares if a manufacturer discontinues support for a specific hardware model.

Our RTUs have generally performed well. Where failures do occur, they immediately become visible to the operations centre and we replace the unit reactively.

Asset health and criticality

As we do not have much data for this asset fleet, we do not have an RTU asset health model yet. Once the data capture exercise is complete, an AHI model similar to that of the other asset fleets will be developed.

Risks

The following table sets out key risks and mitigations we have identified for our RTU fleet.

Table 9.68: Automation and Control System risks

RISK/ISSUE	RISK MITIGATION	MAIN RISK
Malfunction and failure of RTU	Following regular inspection and maintenance regime	Safety Network performance
Communications failure	Regular inspection and monitoring of the optical fibre connectivity Establish strong microwave/radio modes of connectivity	Safety Network performance
Risk of cyber attack	Continuous improvement of security levels in the SCADA system	Safety Network performance

Design and build

We have standardised RTU designs, and installations are now carried out through approved manufacturers. This reduces required spares and lowers total cost of ownership. Detailed design and mapping of RTUs is done during pre-commissioning activities of a substation.

Operate and maintain

Preventive maintenance

RTUs and remote HMIs are regularly inspected and functionally tested as part of regular zone substation maintenance to ensure their ongoing reliability. Being electronic devices, RTUs do not need extensive maintenance.

Corrective maintenance

Corrective maintenance on RTUs and remote HMIs is often limited to system rebooting and software upgrades.

Reactive maintenance

Limited reactive maintenance can be performed for individual components, and obsolete units are typically replaced during substation projects.

Renew or dispose

RTU renewal is typically carried out as part of zone substation projects. RTU replacements outside of the zone substation programme are limited.

Options analysis

During the planning period, we will replace RTUs as part of zone substation upgrades. We also replace RTUs as they become technologically obsolete. Once RTUs reach end of life, or when they are planned for renewal, there are limited alternatives available.

Disposal

RTUs and remote HMI modules that can be used as spares are kept. The disposal requirements are minimal, and they are handled in the same way as other electronic devices.

Automation and control expenditure forecast

Over the AMP period we are forecasting to spend approximately $100k per annum on RTU replacements. This is to cover works carried out as part of substation replacements, ad hoc replacements where identified as obsolete, and reactive replacements.

9.7.9. Communications

The following sections describe our communications fleet. We are currently updating our communications strategy to ensure a consistent lifecycle approach is applied to this fleet. We manage our communications assets through corrective and reactive programmes.

Communications fleet overview

Radio and fibre

Over time, we have built up our fibre and radio (VHF and UHF) capability to cover the entire Northpower region. There are six dedicated VHF voice repeater sites; and six dedicated VHF data sites. We operate a structured voice and data radio access network (RAN). The network is a mixture of VHF and UHF analogue voice, data, repeater, and linking equipment located at the various radio and substation sites. In addition to the repeater sites, we have five substation sites connected via a data RAN. We use fibre to connect to various substations within the access network.

Network resilience

Communication systems play a critical role during and after a hazard event. It is critically important that we have systems in place to ensure the network has sufficient resilience to perform as required during and after these events. Typical examples are as follows.

- Where possible RAN sites are located on fibre or radio ring protected circuits.
- Dual connection paths are made available for mission critical sites.
- Quality power backup systems give additional up time during power failures.
- Critical sites should have power generator capability.
- N-1 systems are used for remote access sites within the access network.
- Sufficient sparing is held to ensure quick replacement during failure.
- Network management systems are in place to ensure faults and failures are quickly dealt with during an emergency.

Voice network

We own and operate our own private land mobile radio network. This provides a radio telephone (RT) service for the exclusive use of our network staff and contractors. The network consists of six VHF repeaters linked through a radio dispatch system at the Whangārei depot. The Whangārei control centre is connected to the radio dispatch

hardware via an ethernet LAN. The backup control room is connected to the radio dispatch hardware via fibre. These repeaters provide a 90% coverage of our distribution area.

There are approximately 150 mobile radios installed in our vehicles and another 21 RT radios located at substations.

Point to multipoint data radio network

We own and operate three point to multipoint (P-MP) networks, which are used to carry control data to remote hardware. The largest of the P-MP networks uses RT technology to link SCADA gateways (located at communications sites) to RTUs on remote hardware. There are 36 reclosers, regulators, and sectionalisers, and 104 switches on this network.

The second network uses a similar RT topology but differs in the solution used for remote RTUs. This network has 26 switches.

The third P-MP network uses VHF utility radios, which are designed specifically to carry control data. This network has completed its pilot and is undergoing a hardware update before additional connections are made. Four reclosers are currently connected to the network.

Point to point radio (WAN radio)

We own and operate 12 point to point radio links which form a radio WAN. The radio WAN connects to a central communications node. The node is connected to our control by fibre. The links carry SCADA, security, management data for substations; the radio WAN also carries management data for radio communications huts. Digitised voice data is carried on one point to point link contained within the WAN. This data facilitates the voice service in the Dargaville region. Ten of the point to point links provide an ethernet interface. One link is being updated to provide an ethernet interface and the remaining link is earmarked for decommissioning.

WAN (fibre)

Twelve substations have distributed fibre connections. We have a leased fibre connection which terminates at Dargaville radio site, and a fibre connection to carry data from the radio site to Dargaville substation.

LAN (substations)

The substation SCADA LANs are standardised with an IP LAN and copper or optical ethernet interfaces. The SCADA LAN is managed by substation engineering. The SCADA LAN is connected into the substation communications LAN via an ethernet switch.

LAN (communications sites)

There are seven communications sites. Six sites have a standard IP LAN with copper or optical ethernet interfaces. The remaining site will be upgraded in the future.

Communications expenditure forecast

Over the planning period we expect to spend approximately $400k per year on our communications network.

Chapter content

10 Supporting Activities

10. SUPPORTING ACTIVITIES

10.1. Introduction

This chapter discusses the business functions and non-network assets that support our electricity network. This includes supporting functions (e.g. human resources and finance) and the staff that directly support our day-to-day asset management activities. Facilities and motor vehicles are also included in this category.

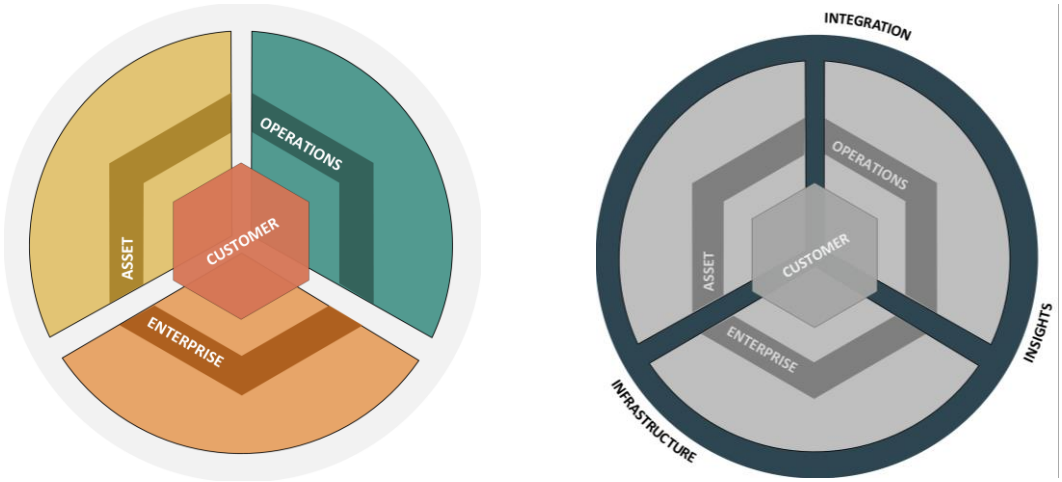
10.2. Business focus areas

We have taken the approach of architecting core platforms by business focus areas:

- asset management (asset)
- customer
- operations
- enterprise and insights (enterprise).

Efficient, clear, and effective business processes are critical to delivering innovative services quickly, at the least possible cost. The following outlines Northpower's multi-layered view of key business processes and how these are supported by effective integration, infrastructure, and business insights.

Figure 10.1: Business process framework



10.3. Core digital platforms to support process areas

Over the past five years, we have invested in quality, best-of-breed digital solutions to support key focus areas around customers, operations, and assets. These investments have:

- set us up with a solid foundation to build upon
- leveraged the capabilities of each of these platforms
- positioned us well to adapt to future change.

Digital teams provide resources to continue to support and respond to changing business needs. They supply design and solution expertise, develop and enhance functionality, improve quality of data, and provide technical support.

10.3.1. Asset management platforms

Information is required for asset management decision-making, and our digital systems are key to providing accurate and timely data. Systems that support our asset management processes are at varying stages of the system lifecycle. We have enabled an uplift in our geospatial capacity with the implementation of Esri. We continue to develop the capabilities of this system and enhance visibility by providing website visitors with fast access to information about our network.

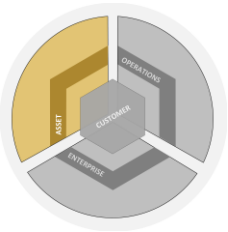
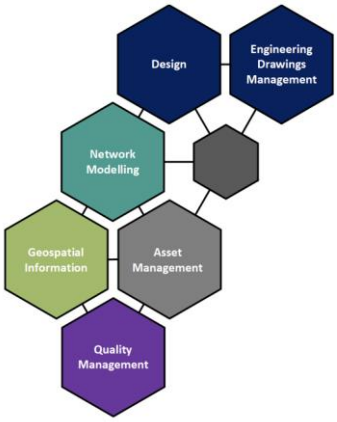


Table 10.1: Description of main asset management platforms

PLATFORM	DESCRIPTION
Design	Construction plans are prepared using AutoCAD and templates.
Engineering drawings management	SharePoint is currently used. A system to replace this is being investigated.
Network modelling	Sincal is used for load flow studies.
Geospatial information	Core GIS is Hexagon G/Technology. A new Esri user interface is being rolled out.
Asset management	Used to manage asset lifecycle data through the EMS WASP system.
Quality management	Q-pulse is used to track HSQE actions. Controlled documents are managed in SharePoint QMS.



Initiatives

Our existing legacy asset management system EMS WASP has been identified for replacement, and we are currently undertaking a scoping and requirements exercise which includes learnings from other New Zealand electricity distribution businesses. This will feed into the system selection process and implementation.

We will take a similar approach to this project as we did with our successful CRM implementation, focusing on our core requirements first, and iteratively learn, grow, and develop over time.

10.3.2. Customer platforms

Our customer relationship management (CRM) platform is now firmly embedded into our business. It plays a key role in supporting a number of processes and underpins all interactions with our customers. The building blocks of our modern CRM platform are strong, and knowledge and expertise in the platform has grown. This positions us well to be able to develop even further functionality into the platform.

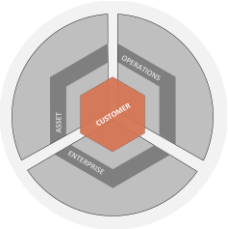
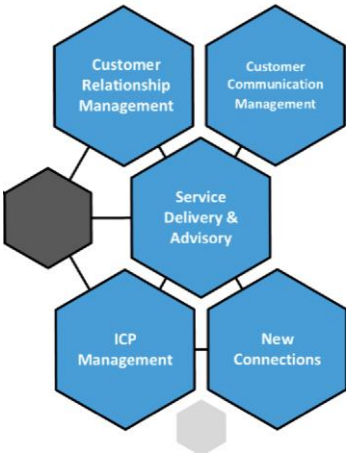


Table 10.2: Description of main customer platforms

PLATFORM	DESCRIPTION
Customer relationship management	Customer information and core customer processes are embedded into Salesforce CRM.
Customer communications management	Customer notification management is through a Salesforce platform with custom extensions. Call centre telephony is currently being replaced with a Genesys solution.
Service delivery and advisory	Our Salesforce CRM supports these processes.
ICP management	Our Axos Billing system and associated interfaces provide a robust link between the electricity registry and a number of our core systems.
New connections	Salesforce is used to manage new connections.



Initiatives

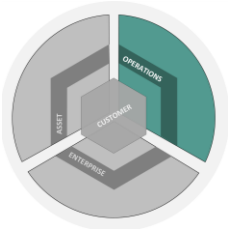
We are in the final stages of developing a solution to fit our customer faults processes into CRM. This will enable us to remove one of our oldest legacy systems entirely from the faults process. The new solution will also enhance the service we provide to our customers by having near real-time information available to call takers. Integration will provide other systems with the data they need in a timely manner.

Also in progress is a contact centre implementation, which will see us move from an outdated phone system to an integrated digital platform with all the features our customers would expect from a modern-day contact centre.

Improvements to our customer portal are ongoing. They include automating previously manual/paper processes, and integration to provide customers with visibility and tracking of work and interactions with our business.

10.3.3. Operations platforms

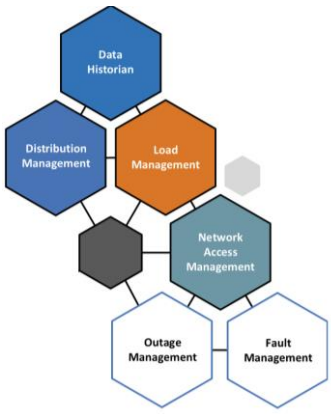
Our digital team helps provision and support the underlying stack for our operations platforms. The advanced distribution management system (ADMS) programme of work brings our SCADA system into the modern era. It gives us an uplift in operational safety with built-in safeguards, and the ability to report on data that was previously difficult to collate and view.



Following on from the success of our 2020 SCADA HV network implementation, we successfully completed another milestone in 2022 with our NOC now operating both the HV and distribution networks electronically (DMS). The second phase of our ADMS roll-out provides improved switching safety logic across the network.

Table 10.3: Description of main operations platforms

PLATFORM	DESCRIPTION
Data historian	Our OSISoft PI Historian keeps time series data from telemetered points on the network.
Distribution management	The second phase of ADMS support network management functions, including GIS to ADMS interface, electronic distribution mimic with geographic views, and switching with safety logic.
Load management	The Catapult OnDemand system provides control of ripple-controlled plant for demand response, tsunami, and streetlight control.
Network access management	The ADMS integrated Zepben EDNAR system allows applicants to raise work requests on the network using the built-in ADMS network viewer. They can then access permits prepared by NOC.
Outage management	Currently a mixture of electronic and manual processes, we will implement an outage management system as part of ADMS phase three.
Fault management	We will implement end-to-end faults management and customer bring faults management processes into CRM.



Initiatives

The planned third phase of our ADMS programme of work in 2023 will be outage management (OMS) and advanced functionality, including distribution power flow (DPF). After that we plan to implement ADMS adaptive network management (ANM) to support greater capacity for planned DER such as solar and wind farms.

10.3.4. Enterprise and insights platforms

Our enterprise and insights applications support all business units and provide core systems for numerous processes. The focus in the asset management space is data sharing, and a number of proof-of-concept initiatives are planned to remove data silos, improve data access, and enhance datasets to support identification and analysis for asset risk and criticality.

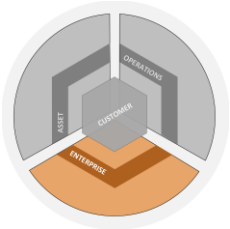


Table 10.4: Description of enterprise and insights platforms

PLATFORM	DESCRIPTION
Records and document management	SharePoint is used as the document management system across Northpower.
IT service desk software	Jira and Jira service desk manages interactions with users and IT resources, based on ITIL framework.
Financial management	Northpower's JDE ERP provides core financials and supply chain functions for all Northpower divisions.
Field force automation	Provided by Northpower's network contractors.
New connections	Salesforce is used to manage new connections.
Human resource management	Cornerstone provides eLearning portals and is used for tracking competencies, qualifications and managing recruitment. PayGlobal is used for remuneration.

Initiatives

Our enterprise and insights applications support all business units, and provide core systems for numerous processes.

The focus in the asset management space is data sharing, and a number of proof-of-concept initiatives are planned to remove data silos, improve data access, and enhance datasets to support identification and analysis for asset risk and criticality.

10.4. Digital expenditure

Our digital team delivers the infrastructure, servers, applications, and tools that support our distribution network operations. Key drivers for our expenditure include:

- **capability development**: development of capabilities identified by business owners (internal customers) subject to digital governance and system/vendor capacity. There is an increasing focus on providing cybersecurity capability to safeguard the network and assets.
- **system maintenance**: systems are regularly patched and tested for security and reliability (disaster recovery capability where applicable). This is covered by Northpower's information security policy.
- **renewal**: digital hardware and operating systems are upgraded/replaced as they become unsupported, typically every five to seven years.

Reflecting the rapid rate of change in the technology industry, an increasing number of the above solutions are being sought and provided as cloud (SaaS) services.

10.5. Non-network functions

In addition to our operations, delivery, and engineering functions (discussed in Chapter 2) we rely on the wider teams within Northpower to ensure we effectively deliver electricity distribution services to our customers. These supporting functions include corporate teams, such as finance, and our people and capability team.

10.5.1. Business support activities

Business support activities are part of our non-network operating expenditure. These includes direct and indirect staffing costs as well as advice we use to complement our internal resource. The key functions supported by this non-network Opex include:

- **people and capability**: attracting and retaining capable and effective people, managing skills and competency development, and fostering a positive working environment. This will be increasingly important as we grow our capability and competency levels over the planning period
- **finance**: includes managing our working capital and debt, purchasing and transaction functions, financial analysis, corporate reporting, and advice
- **health, safety, quality, and environment**: providing leadership and coordination of safety and environmental policies and approaches in support of our operational teams
- **commercial and regulatory**: managing our relationships with regulators and retailers, setting our pricing and commercial direction
- **customer experience**: managing our day-to-day customer interactions, stakeholder engagement, consultation, and general communications
- **digital**: managing and developing the digital platforms used to support the electricity network.

These functions all support our electricity asset management activities. Below we discuss some of the key drivers for this expenditure over the planning period:

- **staff numbers**: directly impacts business support costs. Salary and indirect costs (e.g. consumables) are driven by overall staffing levels
- **external labour market**: staff salaries and other benefits are influenced by the general employment market. Demand for skilled staff, particularly in the regions, will impact the level of competitive salaries
- **business support requirements**: as our network work programme expands, work volumes for areas of support functions will increase
- **digital capability**: licence agreements and costs for third party support and hardware.

These functions play a key role in supporting our operations and ensuring we have the capability and resources necessary to be effective asset managers.

10.5.2. Non-network assets

In addition to our digital assets we own or lease a range of other non-network assets that are used to support our day-to-day asset management activities. These include:

- **offices and facilities**: Northpower owns or leases a number of facilities including office buildings and depots. We aim to ensure that our offices and stores are safe and secure for our employees, are functional and fit for purpose, support improved productivity and efficiency, and are cost-effective to procure and operate. They must also be sized to support future staff growth and materials storage requirements.
- **office equipment**: offices are fitted out with workstations to accommodate our employees. Our offices also host meeting spaces and the office equipment that is required to operate effectively. These assets include desktop and laptop hardware, video conferencing equipment, and peripherals (e.g. printers).
- **vehicles**: we have a fully maintained fleet of vehicles that are leased over a range of terms. An increasing proportion of these are plug-in hybrids or battery EV. We plan to increase this proportion over time in support of emission reduction targets. Our fleet includes vehicles that fit defined criteria, including that vehicles must have a five-star ANCAP safety rating and be fit for purpose, i.e. all-wheel-drive and with suitable ground clearance. Our approach to managing our vehicle fleet is set out in a company policy which specifies how we procure vehicles and associated utilisation rules.

Chapter content

11 Forecast Summary

11. FORECAST SUMMARY

11.1. Introduction

This chapter sets out a summary of our expenditure forecasts over the AMP planning period. The information presented here summarises the investments discussed in earlier chapters. It provides further commentary and context for our forecasts, including key assumptions. It discusses the assumptions used and the uncertainties inherent in developing a 10-year forecast. It should be read in conjunction with the relevant expenditure chapter.

Our AMP includes our current best forecasts, based on our asset management strategies, and using available network information. We expect this profile, particularly later in the period, to be refined as we further enhance our modelling approaches and improve our underlying asset management capability. These refinements will be reflected in subsequent updates of our AMP.

The expenditure forecasts presented here are broadly aligned with information disclosure categories and is consistent with the amounts set out in Schedules 11a and 11b in Appendix B.

Box 11.1: Impact of Cyclone Gabrielle

The planning and engineering analysis underpinning our 2023 AMP was largely undertaken prior to the destructive weather our region experienced in February.

Following efforts to 'get the lights back on', we have turned our focus to understanding the rebuild required. Our work programmes and related expenditure forecasts need to be refined and updated. We will provide further detail on these in our 2024 asset management plan update.

We have not updated expected outturns for FY23 to reflect the reactive expenditure we have incurred to ensure customers could be safely reconnected. These amounts will be reconciled in future disclosures.

Below we summarise our Capex and Opex forecasts for the AMP period, together with cross references to chapters where more detailed information is provided.

11.2. Capex

As discussed in Chapter 6, we have adopted a lifecycle-based approach to managing our electricity distribution assets. We reflect these stages in the categories we use to explain our investments in network assets. In addition, we use the term 'non-network Capex to describe investment in assets that support our electricity distribution service.

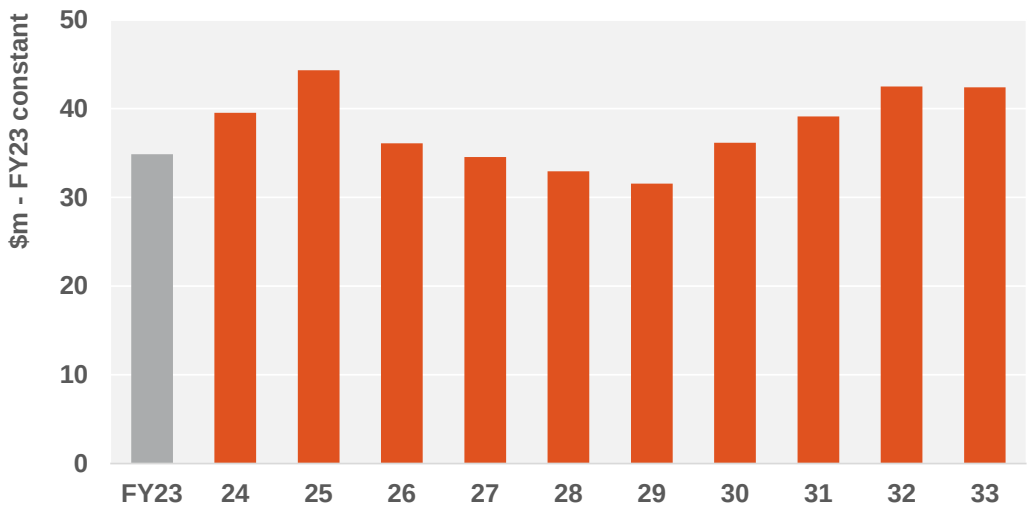
11.2.1. Total Capex

Overall Capex includes the following categories:

- **Network development Capex**: relates to capital investments that increase the capacity, functionality, or size of our network. These are discussed in Chapter 8.
- **Customer connections Capex**: the cost of connecting new customers to our network. These are discussed in Chapter 8.
- **Asset lifecycle management Capex**: expenditure used to replace or refurbish existing assets on our networks. Our approach to asset lifecycle management is discussed in Chapter 9.
- **Other network Capex**: the cost of relocating our assets to facilitate third-party developments, and specific initiatives to improve safety or reliability or to reduce the environmental impact of our assets. These are discussed in Chapter 9.
- **Non-network Capex**: our investment in those assets that support and enable our asset management activities. The drivers for these investments are discussed in Chapter 10.

Below we set out our total Capex for the planning period.

Figure 11.1: Forecast total Capex over the planning period (net of contributions)



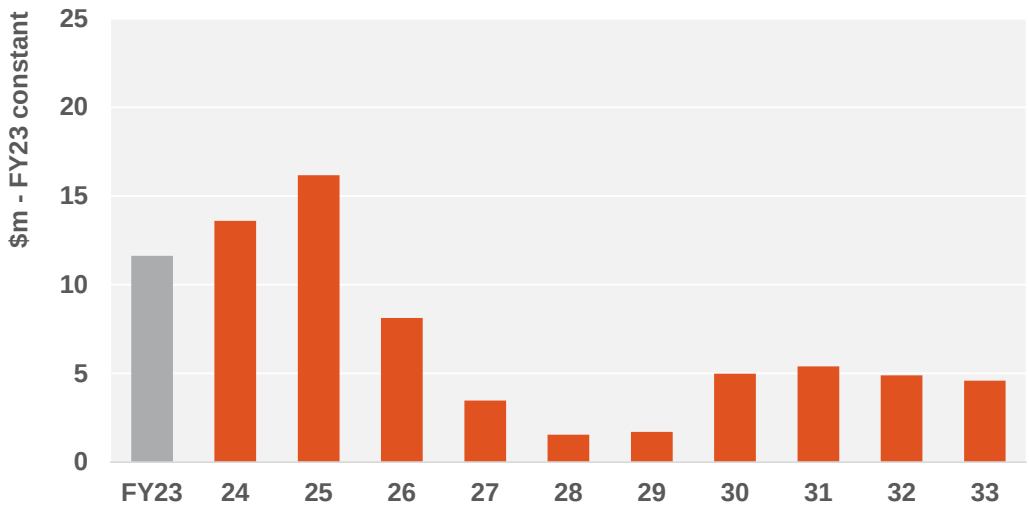
The planned Capex on our network is $379.2 million over the 10-year planning period, FY24–FY33. This represents a significant increase on historical levels. This level of expenditure is required to meet the investment needs of our ageing asset base and is necessary to ensure a long-term safe and reliable supply for customers. We intend to focus on a number of key fleets and initiatives over the next decade.

11.2.2. Network development

Investments to develop our network are primarily driven by load growth and the changing behaviours and needs of our customers. Developments at the subtransmission level tend to be more predictable than those at distribution level, which allows these projects to be planned further out. Projects at distribution level are more closely linked to shorter-term

economic activity, such as housing development and changes in consumer demand, with the result that we expect some flexibility in our short-term plans. These investments are covered in more detail in Chapter 8.

Figure 11.2: Forecast network development Capex over the planning period

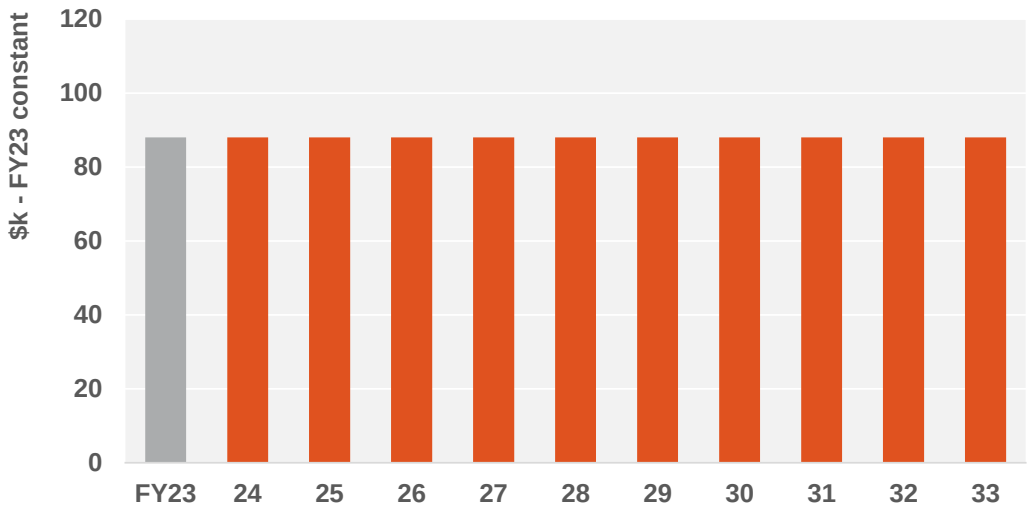


In the initial years of the period we will carry out some large growth projects. This includes upgrading the Kensington substation and constructing a new zone substation at Mangawhai. These larger investments are expected to drop off in the middle of the planning period before picking back up closer to the end of the period, with the development of a new zone substation at Waipu and a line from Ruakākā to Waipu. For more detail on the planned projects, refer to Chapter 8 and Appendix C.

11.2.3. Customer connections

Customer connections expenditure includes expenditure Northpower incurs when connecting new customers to its network.

Figure 11.3: Forecast customer connections Capex over the planning period (net of contributions)

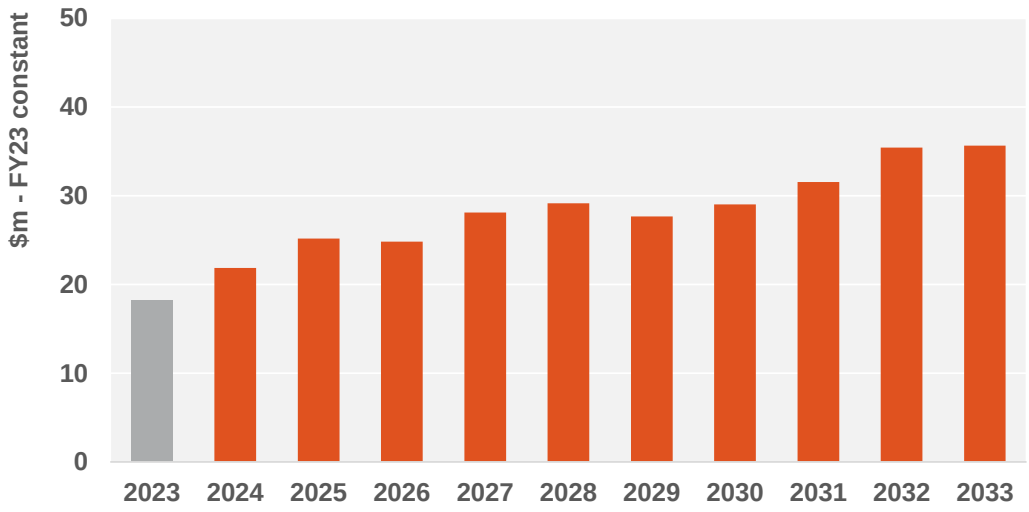


Our forecast over the 10-year period in the customer connections expenditure category is relatively low. This is due to the recent change in our customer contribution policy, meaning that expenditure on new connections is largely covered by developers, with some small exceptions for single dwelling connections.

11.2.4. Renewals

Our renewals expenditure category includes expenditure to replace and refurbish our existing assets. This is our largest expenditure category and we expect this to ramp up over the planning period as we address our ageing asset base. This category is covered in more detail in Chapter 9.

Figure 11.4: Forecast renewals Capex over the planning period



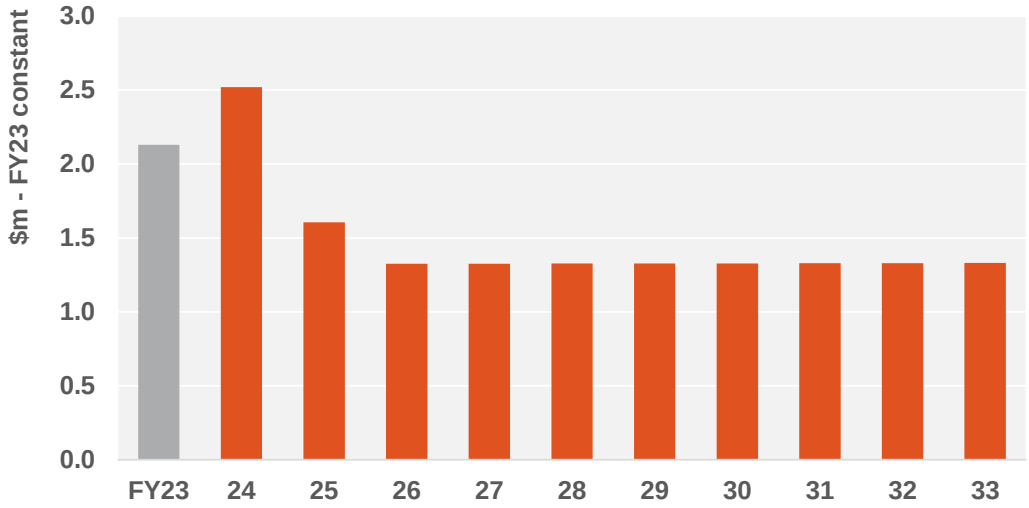
Over the 10-year period, we plan to invest significantly more in asset renewal than we have historically. This is required to manage our ageing asset fleet, which has more assets reaching end of life. We need to ramp up our replacement volumes to maintain our asset condition and continue providing a reliable service.

Over the 10-year period, the largest proportion of forecast spend is in the overhead lines portfolio, with 62% of the expenditure forecast on these assets. This is followed by 15% for zone substations and 13% for distribution equipment. In the short term, renewal spend is mainly focused in the zone substations portfolio as we ramp up our expenditure on overhead lines and distribution asset replacements.

11.2.5. Other network Capex

Our other network Capex category includes the Commerce Commission categories of asset relocations, and reliability, safety, and environment.

Figure 11.5: Forecast other-network Capex over the planning period



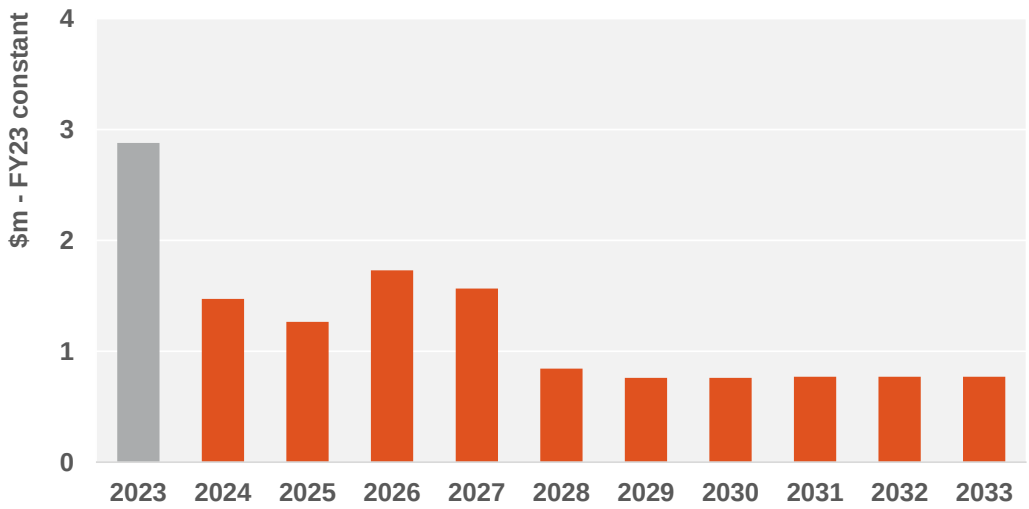
The major reliability, safety, and environment investment in the short term is improving the reliability of the Kensington substation 110kV bus. The remainder of the period includes expenditure on overhead-to-underground conversions and investment in LV visibility.

Asset relocations spend includes the portion of the cost that Northpower covers to relocate assets following customer requests. By its nature, asset relocations expenditure is difficult to predict with certainty. Our forecast is based on average historical spend and is approximately $0.4 million per annum.

11.2.6. Non-network Capex

Our non-network Capex category includes expenditure on digital systems and other non-network assets that support the network and our asset management activities.

Figure 11.6: Forecast non-network Capex over the planning period



In the initial years of the planning period, we have some large digital projects planned. These include the remainder of the advanced distribution management system upgrade

and the new asset management information system (AMIS). Over the remainder of the period we have forecast an allowance for smaller process and analytics improvement projects.

11.3. Opex

Our Opex forecast includes our forecast expenditure across five portfolios:

- routine, corrective maintenance and inspections
- asset replacement and renewal
- service interruptions and emergencies
- vegetation management
- non-network.

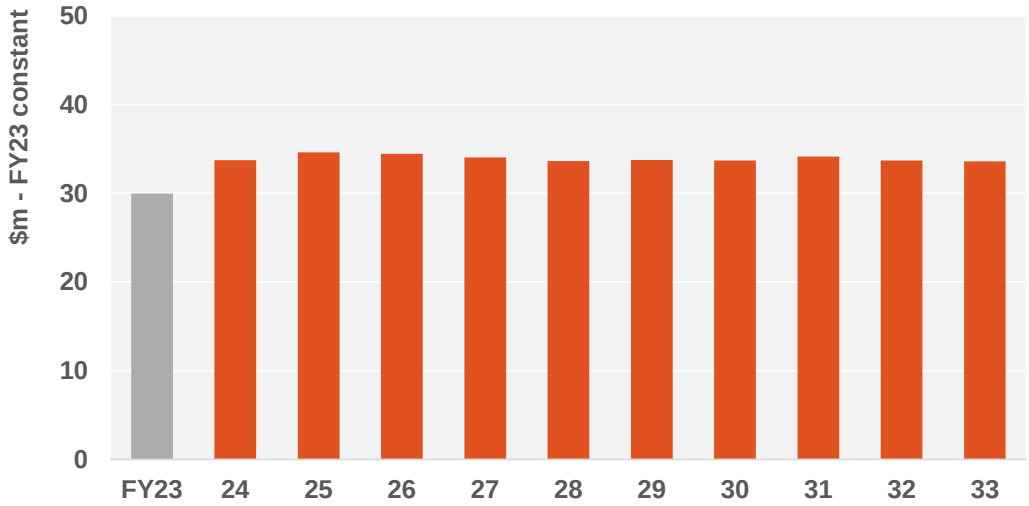
The following sections set out our planned Opex for each of the five portfolios. Further information on the forecasts can be found in Chapters 9 and 10.

We carry out a range of maintenance activities to ensure our network assets provide the required capability in a safe and reliable manner throughout their useful life. Our internal maintenance categories differ from those used in information disclosure. However, for consistency we have set out our forecasts here to align with our disclosure in Schedule 11b (see Appendix B). An explanation of our internal maintenance categories is included in Chapter 6.

11.3.1. Total Opex

Below we set out forecast for total Opex during the AMP planning period.

Figure 11.7: Forecast total Opex over the planning period

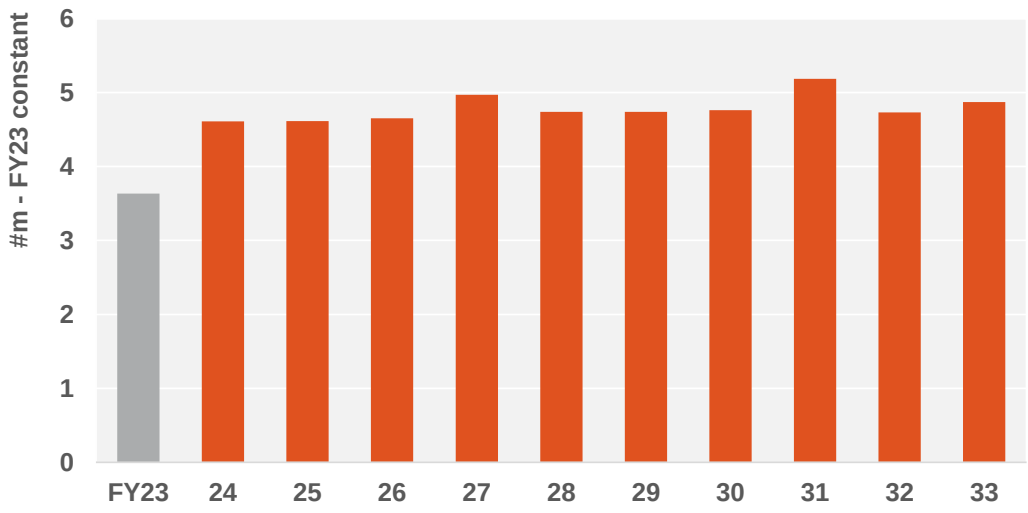


Our total Opex forecast is relatively stable over the planning period, FY24–FY33, with our total 10-year expenditure at $339.4 million.

11.3.2. Routine, corrective maintenance and inspections

Routine, corrective maintenance and inspections (RCI) includes preventive maintenance activities. It is scheduled work, including servicing to maintain asset integrity, and inspections to compile condition information for subsequent analysis and planning. Our programmes reflect industry norms relating to inspection, and we are increasingly moving to an approach based on condition and criticality in these areas. RCI is our most regular asset intervention and is a key input into our asset management decision-making.

Figure 11.8: Forecast RCI Opex over the planning period



Over the 10-year AMP period we plan to spend $47.9 million on routine, corrective maintenance, and inspections. Under this expenditure category we also undertake value-added maintenance – activities carried out by Northpower to ensure the safety of the public. These include cable location, high load management, safety disconnects, and corrective activities on service lines. Our highest forecast spend is in this area. Of the portfolio-specific spend, the largest proportion is in overhead lines, making up approximately 31% of the portfolio maintenance. The breakdown of the expenditure is shown in Table 10.1.

Table 11.1: Forecast RCI Opex broken down by portfolios

PORTFOLIO	10-YEAR TOTAL EXPENDITURE ($)
Overhead lines	10.5m
Substation equipment	6.2m
Distribution equipment	7.3m
Cables	3.3m
Earthing systems	4.8m
Secondary systems	1.3m
Auxiliary systems	0.2m
Other	14.3m
Total	**47.9m**

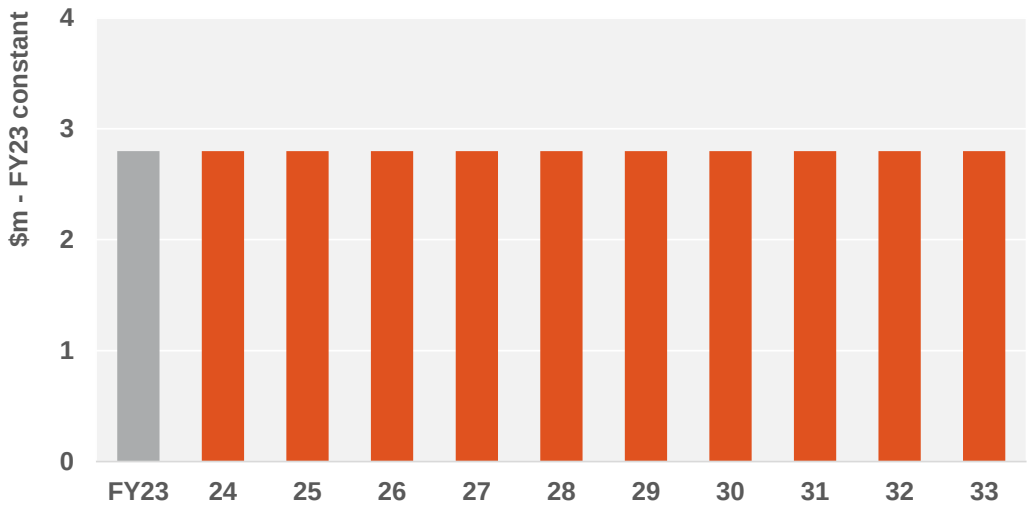
11.3.3. Service interruptions and emergencies maintenance

Service interruptions and emergencies (SIE) Opex includes expenditure incurred in response to network faults and other incidents. This is reactive work with no advanced scheduling other than ensuring that there are sufficient resources on standby to respond to network faults. SIE maintenance focuses on safely restoring supply to customers. It is especially prevalent during and after large events such as major storms.

Box 11.2: Costs related to Cyclone Gabrielle

Note that the costs of restoring service following Cyclone Gabrielle had not yet been reconciled into the FY23 year-end forecast at the time of writing this AMP.

Figure 11.9: Forecast SIE Opex over the planning period



Over the period we expect to spend $28.0 million on SIE. SIE is difficult to forecast with certainty as it is based on fault numbers, which are influenced by external drivers such as weather and third-party interference. The flat forecast is consistent with maintaining levels of historical reliability. The breakdown by portfolio is shown in Table 10.2.

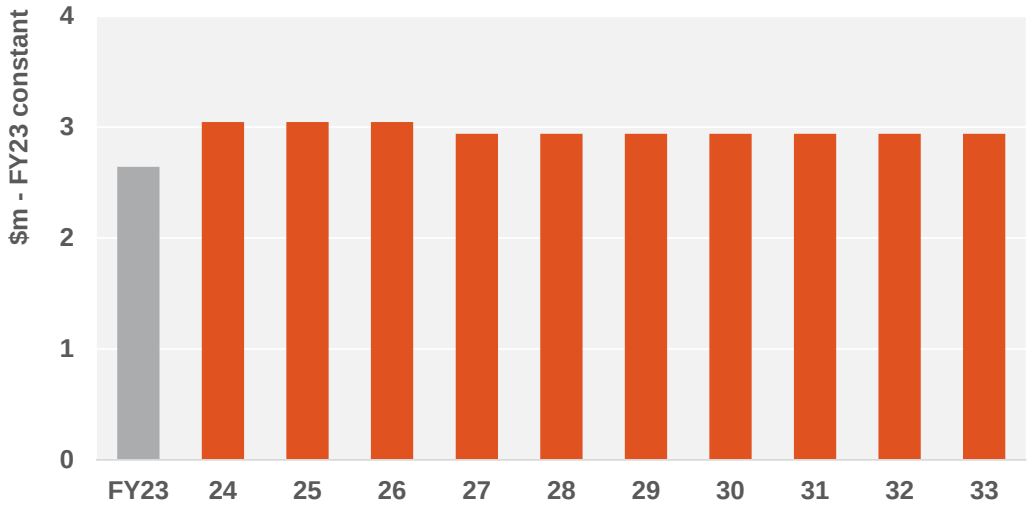
Table 11.2: Forecast SIE Opex broken down by portfolios

PORTFOLIO	10-YEAR TOTAL EXPENDITURE ($)
Overhead lines	18.8m
Substation equipment	1.3m
Distribution equipment	1.8m
Cables	3.9m
Earthing systems	90k
Secondary systems	0.5m
Auxiliary systems	1.2m
Other	0.4m
Total	**27.9m**

11.3.4. Asset replacement and renewal maintenance

Asset replacement and renewal (ARR) Opex relates to corrective maintenance. It is generally undertaken to rectify defects and ensure assets continue to provide reliable service throughout their useful life.

Figure 11.10: Forecast ARR Opex over the planning period



Over the 10-year AMP period we expect to spend $29.7 million on ARR. The largest proportion of forecast spend is in the overhead lines portfolio, making up approximately 46% of the total corrective budget. The breakdown of expected spend by portfolio is shown in Table 10.3.

Table 11.3: Forecast ARR Opex broken down by portfolios

PORTFOLIO	10-YEAR TOTAL EXPENDITURE ($)
Overhead lines	13.5m
Substation equipment	5.4m
Distribution equipment	7.7m
Cables	0.5m
Earthing systems	0.3m
Secondary systems	0.6m
Auxiliary systems	0.5m
Other	1.1m
Total	**29.7m**

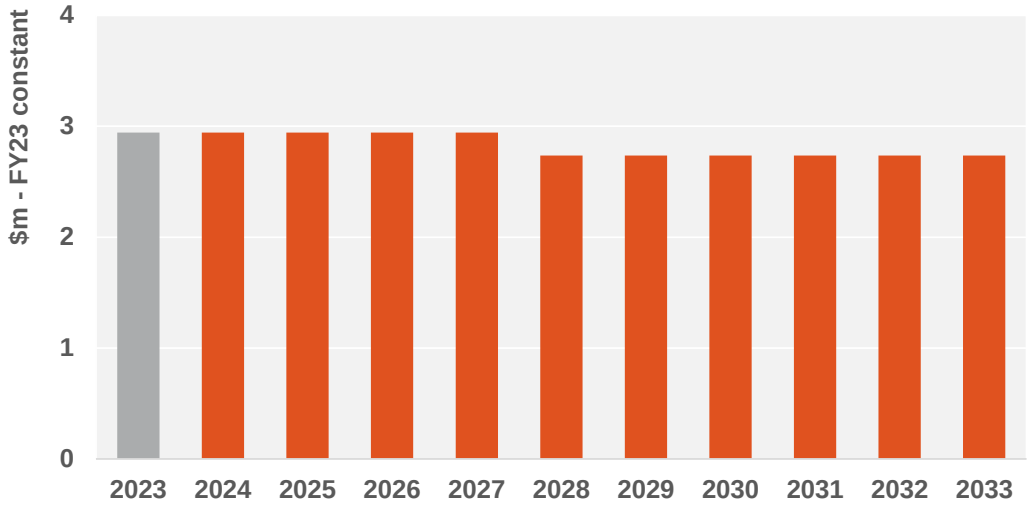
11.3.5. Vegetation management

We undertake vegetation management to keep trees clear of overhead lines. This is necessary to minimise vegetation-related outages and meet our safety and statutory obligations. The main activities we carry out are inspections to determine the amount of

work required, liaison with landowners when work is required, and subsequent follow-up tree trimming and removal.

The following chart below shows our forecast vegetation management Opex during the planning period.

Figure 11.11: Forecast vegetation management Opex over the planning period



Over the 10-year AMP period we plan to spend $31.9 million on vegetation management. We are currently shifting from a cyclical vegetation management strategy to a risk-based strategy. We expect to fully embed this strategy and complete a full cycle by 2027. At this point we have forecast a modest reduction in expenditure, reflecting the more efficient use of resources to manage network vegetation risk.

The main expected benefits of vegetation management work over the planning period are:

- **management of safety risk**: the risks of our workforce and the public being exposed to injury are reduced by carrying out the work in accordance with our safety and operational procedures.
- **Improved customer experience/service**: reducing unplanned outages will improve the network reliability experienced by our customers.
- **Compliance**: ensures that the network is in full compliance with the requirements set out in the tree regulations.
- **Engagement**: increased stakeholder awareness around risks associated with vegetation near conductors.

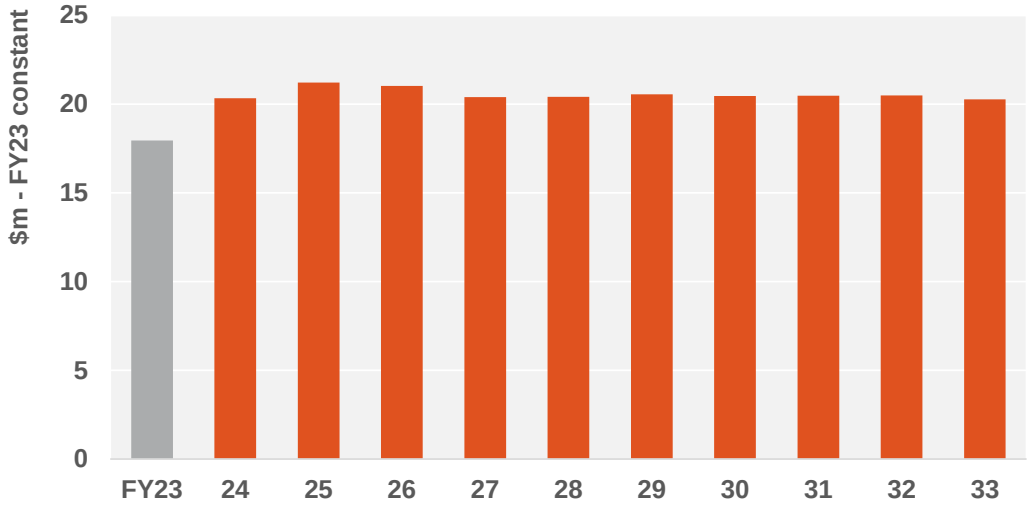
11.3.6. Non-network Opex

Non-network Opex includes two main expenditure categories as defined in information disclosure.

- **Business support**: includes the costs associated with support functions such as HR and finance, as well as ICT-related Opex. This is discussed further in Chapter 10.

– **System operations and network support**: indirect network Opex where the primary driver is the management of the network. It includes expenditure relating to engineering staff, NOC, and system operations.

Figure 11.12: Forecast non-network Opex over the planning period



Over the 10-year planning period we plan to spend $205.6 million on non-network Opex. We are planning a modest uplift into FY24, reflecting the need for increased capability to manage the network and meet the challenges outlined in this AMP. We expect that these levels of expenditure will largely continue for the remainder of the period.

11.4. Underlying assumptions

The following inputs and assumptions have informed our overall forecasting approaches.

11.4.1. Forecasting uncertainties

Our AMP includes our current best forecasts based on our asset management strategies and using available network information. In subsequent updates, we expect the profiles, particularly later in the period, to be further refined as we collect improved asset information and enhance our modelling approaches.

Box 11.3: Scale of cyclone damage yet to be fully quantified

As discussed elsewhere, at the time of publishing this AMP we had not undertaken any material analysis of renewal and network remediation need beyond that required to restore customer service.

We need to understand the condition of our network following this event and may need to rebuild certain parts of the network to restore a sustainable level of network condition. We are beginning to develop these plans and will include the required investments in future disclosures.

Below we set out some examples of the assumptions underpinning our forecasts for the planning period. Further assumptions are discussed in relevant chapters.

- We have used available asset information and applied assumptions to develop our renewal forecasts. There is known uncertainty in both the data and assumptions, but we expect that the overall level of expenditure is forecast at the right level. We will continue to refine our asset information and assumptions to improve the accuracy of these forecasts.
- DER uptake will not have a material impact on network investment needs in the planning period. We have assumed that the installation of PV and energy storage will not materially affect peak load growth or related investment requirements over the planning period. We will review this assumption as the period progresses.
- Customers are happy with current reliability levels and do not expect performance to degrade over the long term. We will continue our engagement with customers to assess whether this remains the case.
- Historical unit rates are appropriate for use in volumetric forecasts (discussed below).
- Relationships between growth drivers (e.g. ICP growth) and future demand will continue to apply in the short term. In the medium term the increasing adoption of new technologies may alter these relationships, and we are monitoring these trends carefully.

In developing forecast and investment strategies over a 10-year AMP period there needs to be flexibility; for example, using scenarios to support planning decisions. In future AMPs we will provide further detail on these scenarios.

11.4.2. Cost estimation

Good practice cost estimation uses a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level, depending on the nature of the work. The development of estimates can be complex, leading to a degree of uncertainty and estimation risk, especially for longer-term forecasts.

Investments are estimated using our cost estimation process which differs depending on the type of project. The two main estimate types are explained below.

- **Volumetric projects**: for large-volume, low-cost replacement programmes, a volumetric unit rate is used to estimate the programme costs. We use P50[40] unit rates derived using historical out-turn costs.
- **Customised estimates**: for low-volume and one-off projects, a desktop study of the project is used to determine an estimate and a breakdown of the scope, to which unit rates are applied. As the project moves into delivery, the scope and cost estimate become more accurate through further engineering investigation and detailed design.

[40] A P50 cost is an estimate of a cost based on a 50% probability that the cost will not be exceeded.

11.4.3. Historical unit rates

In general, historical unit rates reflect future volumetric work scopes and risks at an aggregate or portfolio level. While we continue to aim for efficiency in all aspects of our work delivery, our experience has shown that increased efficiency tends to be offset by increased safety-related costs (such as traffic management) and costs associated with accessing the road corridor and private land.

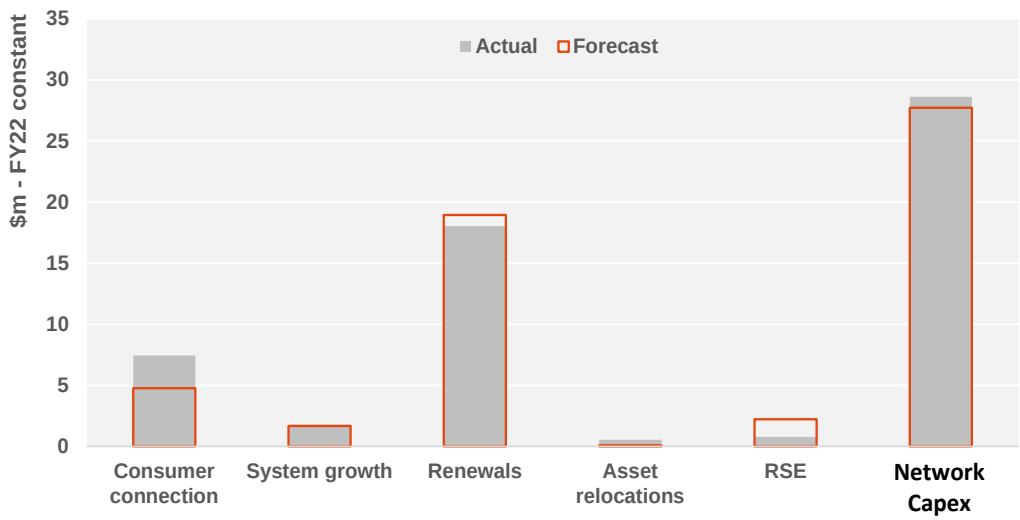
11.4.4. Price escalation

There are a number of inputs and assumptions underpinning our forecasts for the planning period. These include our approach to escalating our forecasts to nominal dollars. Over the AMP period we expect to face different input price pressures to those captured by a general measure of inflation like CPI. We expect that the input price increases we face over the planning period will be greater than CPI, due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.

11.5. Financial progress against plan

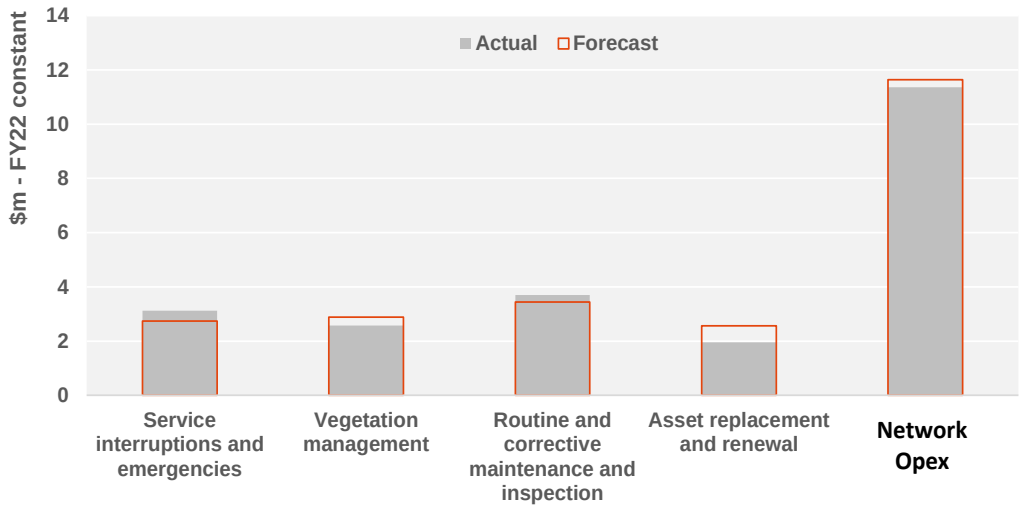
Total expenditure on our network in FY22 was largely in line with the FY22 AMP forecast. There are some variances between categories as shown in the figures below.

Figure 11.13: Comparison between actual FY22 network Capex and our AMP22 forecast



Overall, we delivered close to the budgeted levels of network Capex in FY22. The largest variance in spend was in the consumer connection portfolio. This is a difficult expenditure category to forecast as it is largely driven by third-party decisions and other external factors. We saw a larger number of customer connections in FY22 than expected. We delivered marginally less than expected in the renewals and RSE categories due to Covid-19 disruptions and delivery constraints.

Figure 11.14: Comparison between actual FY22 network Opex and our AMP22 forecast



Overall, our FY22 network Opex was slightly below our budgeted network Opex, with some minor variances in each category. The largest variance was in the asset replacement and renewal area where we delivered less than expected due to delivery constraints and Covid 19 disruption.

11.6. Overall AMP forecast comparison

The following table explains the variances in our overall expenditure forecasts since our last AMP disclosure in 2022. These reflect changes in forecast expenditure (by information disclosure category) during the overlapping period, i.e. FY24 to FY31 inclusive. All amounts are in nominal dollars.

Table 11.4: Expenditure profile comparison (nominal, 000's)

	AMP22	AMP23	% CHANGE	COMMENTS
Capex				
Consumer connection (gross)	38,487	51,549	34%	We have updated our consumer connection forecast based on recent expenditure and expected future connections.
System growth	33,193	59,446	79%	Some projects transferred from RSE due to refined needs definition. Includes updated forecasts for some major projects.
Asset replacement and renewal	116,889	242,457	107%	Updated renewals modelling, identifying additional poor condition overhead lines, distribution, and substation equipment.
Asset relocations (gross)	980	2,959	202%	Updated the asset relocations forecast based on recent expenditure and expected requests.

	AMP22	AMP23	% CHANGE	COMMENTS
Reliability, safety and environment	20,342	10,345	-49%	A major proportion of this change was classifying some projects to system growth based on refined need definitions.
Expenditure on non-network assets	5,895	10,054	71%	Gained a better understanding of longer-term non-network asset expenditure required.
Opex				
Service interruptions and emergencies	25,965	24,862	-4%	Minor adjustments
Vegetation management	26,222	25,189	-4%	Minor adjustments
Routine and corrective maintenance and inspection	34,666	42,551	23%	Inclusion of new maintenance requirements – mainly related to conductor testing and LV pillars.
Asset replacement and renewal	23,830	26,446	11%	Updated expectations around corrective maintenance following modelling work.
Non-network	138,029	181,504	31%	Forecast uplift to meet new challenges and uplift capability.

Overall, the only significant change in Capex was in the asset replacement and renewal category, where we have modelled our required expenditure based on asset data rather than historical expenditure. This has resulted in a significant uplift in forecast expenditure in this category.

Other notable changes in Capex were in the growth and RSE categories, where we have clarified the need for some projects and transferred these from RSE to growth. We have also seen a significant increase in costs over the past two years and have updated our major growth project forecasts based on this updated information. We have also updated our consumer connection and asset relocation forecasts based on recent expenditure and insights into future third-party requests.

In network Opex we have seen some uplift in the RCI category following identification of new maintenance requirements. The main requirement is to implement conductor sample testing, following a review of our conductor replacement approach. This will help to improve our conductor modelling and ensure that we are only replacing conductor that is at end of life. We have also reviewed our expected corrective maintenance forecast based on insights from our forward renewal requirements.

In non-network Opex we have forecast increased requirements, reflecting the need for more capability to manage the network and meet the new challenges outlined in this AMP. This includes the uplift in renewals as our asset base ages, improving resilience, addressing climate change risk, improving asset management capability, and adapting to meet new customer technology demands.

Appendices

Appendices

APPENDIX A. GLOSSARY

ACRONYM / TERMS	MEANING
ABS	Air break switch
AAAC	All aluminium alloy conductor
AAC	All aluminium conductor
ACSR	Aluminium conductor steel reinforced (cable)
ADMS	Advanced distribution management system
AHI	Asset health indicator
AMIS	Asset management information system
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
ANCAP	Australian new car assessment programme
BCP	Business continuity planning
CB	Circuit breaker
CAIDI	Consumer average interruption duration index
Capex	Capital expenditure
CIMP	Coordinated incident management plan
Cu	Copper
DER	Distributed energy resources
DG	Distributed generation
DGA	Dissolved gas analysis
DPP	Default price-quality path
DSM	Demand side management
EDB	Electricity distribution business
EDO	Expulsion dropout (HV fuse or link)
EEA	Electricity Engineer's Association of New Zealand
EV	Electric vehicle
FY	Financial year
Gentrack	Network billing system
GIS	Geospatial Information System
GWh	Gigawatt hour
GXP	Grid exit point
HILP	High impact low probability (events)
HR	Human resources
HV	High voltage

ACRONYM / TERMS	MEANING
ICP	Installation control point
IEDs	Intelligent electronic devices
ISO	International Standards Organisation
KPI	Key performance indicator
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LiDAR	Light Detection and ranging
LV	Low voltage
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
N security	Unable to take full load with loss of a single element
N-1 security	Able to take full load with loss of a single element
NEPT	Northpower Electric Power Trust
NOC	Network operations centre
NPV	Net present value
NZTA	New Zealand Transport Agency
NBS	New Building Standard
OLTC	On load tap changer
Opex	Operational expenditure
PILC	Paper insulated lead cable
PV	Photo-voltaic
PVC	Poly vinyl chloride
RAS	Risk appetite statement
RC	Replacement cost
RMU	Ring Main Unit (distribution switchgear)
RSE	Reliability, Safety and Environment (Capex)
RTU	Remote Terminal Unit
SAIDI	System average interruption duration index (minutes)
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition System
SCI	Statement of corporate intent

ACRONYM / TERMS	MEANING
SF_6	Sulphur hexafluoride
SINCL	Power system simulation software
SLA	Service level agreement
UG	Underground
V	Volt
VAR	Volt Ampere (reactive)
VLI	Very large industrial customer
VoLL	Value of Lost Load
WASP	Works, assets, solutions, and people (maintenance management system)
XLPE	Cross linked polyethylene cable

APPENDIX B. DISCLOSURE SCHEDULES

This appendix includes the following Information Disclosure schedules:

- Schedule 11a: report on forecast Capital Expenditure
- Schedule 11b: report on forecast Operational Expenditure
- Schedule 12a: report on asset condition
- Schedule 12b: report on forecast capacity
- Schedule 12c: report on forecast network demand
- Schedule 12d: report on forecast interruptions and duration
- Schedule 13: report on asset management maturity
- Schedule 14a: commentary on differences between forecast Capex (schedule 11a) and Opex (schedule 11b) in nominal and constant prices

Schedule 11a: report on forecast Capital Expenditure

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	3,637	5,972	6,115	6,256	6,381	6,508	6,639	6,771	6,907	7,045	7,186
11	System growth	11,611	13,980	17,028	8,749	3,806	1,724	1,949	5,801	6,409	5,932	5,667
12	Asset replacement and renewal	18,168	22,496	26,545	26,774	30,916	32,689	31,640	33,857	37,540	43,018	44,142
13	Asset relocations	112	340	349	358	366	374	383	391	400	409	418
14	Reliability, safety and environment:											
15	Quality of supply	1,342	1,774	852	66	67	69	70	71	73	74	76
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	676	479	491	1,004	1,024	1,045	1,066	1,087	1,109	1,131	1,153
18	**Total reliability, safety and environment**	2,018	2,253	1,342	1,070	1,091	1,113	1,136	1,158	1,181	1,205	1,229
19	**Expenditure on network assets**	35,546	45,040	51,380	43,207	42,559	42,408	41,746	47,978	52,438	57,609	58,642
20	Expenditure on non-network assets	2,877	1,516	1,333	1,865	1,720	948	869	887	916	935	953
21	**Expenditure on assets**	38,423	46,556	52,712	45,071	44,279	43,356	42,616	48,865	53,355	58,544	59,595
22												
23	*plus* Cost of financing	666	1,330	1,502	1,287	1,274	1,261	1,248	1,440	1,583	1,748	1,477
24	*less* Value of capital contributions	3,549	5,881	6,022	6,161	6,284	6,410	6,538	6,669	6,802	6,938	7,077
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	35,540	42,005	48,192	40,198	39,269	38,207	37,326	43,636	48,135	53,353	53,996
28												
29	Assets commissioned	15,042	32,400	50,900	62,511	40,784	41,148	38,336	41,347	51,084	52,170	63,631
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
32		**$000 (in constant prices)**										
33	Consumer connection	3,637	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803	5,803
34	System growth	11,611	13,586	16,160	8,117	3,461	1,537	1,704	4,972	5,386	4,887	4,577
35	Asset replacement and renewal	18,168	21,862	25,193	24,838	28,118	29,148	27,660	29,017	31,543	35,437	35,650
36	Asset relocations	112	330	331	332	333	334	334	335	336	337	338
37	Reliability, safety and environment:											
38	Quality of supply	1,342	1,724	808	61	61	61	61	61	61	61	61
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	676	466	466	932	932	932	932	932	932	932	932
41	**Total reliability, safety and environment**	2,018	2,189	1,274	993	993	993	993	993	993	993	993
42	**Expenditure on network assets**	35,546	43,771	48,761	40,083	38,708	37,814	36,494	41,120	44,061	47,457	47,360
43	Expenditure on non-network assets	2,877	1,473	1,265	1,730	1,565	845	760	760	770	770	770
44	**Expenditure on assets**	38,423	45,244	50,026	41,813	40,273	38,659	37,254	41,880	44,831	48,227	48,130
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	168	312	452	577	705	835	968	1,103	1,242	1,382
System growth		-	394	868	633	344	187	245	829	1,024	1,045	1,090
Asset replacement and renewal		-	634	1,353	1,936	2,797	3,541	3,980	4,840	5,997	7,581	8,492
Asset relocations		-	10	18	26	33	41	48	56	64	72	80
Reliability, safety and environment:												
Quality of supply		-	50	43	5	6	7	9	10	12	13	15
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		-	14	25	73	93	113	134	155	177	199	222
Total reliability, safety and environment		-	63	68	77	99	121	143	166	189	212	236
Expenditure on network assets		-	1,269	2,618	3,124	3,851	4,594	5,252	6,858	8,377	10,152	11,281
Expenditure on non-network assets		-	43	68	135	156	103	109	127	146	165	183
Expenditure on assets		-	1,312	2,686	3,259	4,007	4,696	5,361	6,985	8,523	10,317	11,465

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
11a(ii): Consumer Connection							
*Consumer types defined by EDB**		$000 (in constant prices)					
Consumer Connections (gross)		3,637	5,803	5,803	5,803	5,803	5,803
include additional rows if needed							
Consumer connection expenditure		3,637	5,803	5,803	5,803	5,803	5,803
less Capital contributions funding consumer connection		3,549	5,715	5,715	5,715	5,715	5,715
Consumer connection less capital contributions		88	88	88	88	88	88
11a(iii): System Growth							
Subtransmission		2,070	3,235	7,662	3,356	1,892	-
Zone substations		7,872	8,315	6,563	3,159	-	-
Distribution and LV lines		129	414	100	294	576	564
Distribution and LV cables		-	-	-	-	-	-
Distribution substations and transformers		1,540	1,559	1,835	1,308	994	973
Distribution switchgear		-	64	-	-	-	-
Other network assets		-	-	-	-	-	-
System growth expenditure		11,611	13,586	16,160	8,117	3,461	1,537
less Capital contributions funding system growth							
System growth less capital contributions		11,611	13,586	16,160	8,117	3,461	1,537

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
91							
92	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
93	**11a(iv): Asset Replacement and Renewal**	$000 (in constant prices)					
94	Subtransmission	391	421	452	1,585	2,813	517
95	Zone substations	8,907	9,156	10,768	6,140	4,612	4,152
96	Distribution and LV lines	6,704	8,492	10,747	13,393	16,383	19,684
97	Distribution and LV cables	193	1,328	262	279	303	336
98	Distribution substations and transformers	467	631	838	1,131	1,443	1,684
99	Distribution switchgear	1,083	1,413	1,703	1,887	2,141	2,350
100	Other network assets	423	423	423	423	423	423
101	**Asset replacement and renewal expenditure**	18,168	21,862	25,193	24,838	28,118	29,148
102	*less* Capital contributions funding asset replacement and renewal						
103	**Asset replacement and renewal less capital contributions**	18,168	21,862	25,193	24,838	28,118	29,148
104							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
105							
106	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
107	**11a(v): Asset Relocations**						
108	*Project or programme**	$000 (in constant prices)					
109	Asset relocations (gross)	112	330	331	332	333	334
110							
111							
112							
113							
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	112	330	331	332	333	334
117	*less* Capital contributions funding asset relocations						
118	**Asset relocations less capital contributions**	112	330	331	332	333	334
119							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
120							
121	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
122	**11a(vi): Quality of Supply**						
123	*Project or programme**	$000 (in constant prices)					
124	All QoS projects	1,342	1,724	808	61	61	61
125							
126							
127							
128							
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply						
131	**Quality of supply expenditure**	1,342	1,724	808	61	61	61
132	*less* Capital contributions funding quality of supply						
133	**Quality of supply less capital contributions**	1,342	1,724	808	61	61	61
134							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
11a(vii): Legislative and Regulatory							
*Project or programme**		$000 (in constant prices)					
*include additional rows if needed							
All other projects or programmes - legislative and regulatory							
Legislative and regulatory expenditure		-	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
11a(viii): Other Reliability, Safety and Environment							
*Project or programme**		$000 (in constant prices)					
All ORSE projects		676	466	466	932	932	932
*include additional rows if needed							
All other projects or programmes - other reliability, safety and environment							
Other reliability, safety and environment expenditure		676	466	466	932	932	932
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		676	466	466	932	932	932

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
11a(ix): Non-Network Assets							
Routine expenditure							
*Project or programme**		$000 (in constant prices)					
Routine expenditure		719	215	215	220	230	235
*include additional rows if needed							
All other projects or programmes - routine expenditure							
Routine expenditure		719	215	215	220	230	235
Atypical expenditure							
*Project or programme**							
Atypical expenditure		2,158	1,258	1,050	1,510	1,335	610
*include additional rows if needed							
All other projects or programmes - atypical expenditure							
Atypical expenditure		2,158	1,258	1,050	1,510	1,335	610
Expenditure on non-network assets		2,877	1,473	1,265	1,730	1,565	845

Schedule 11b: report on forecast Operational Expenditure

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,799	2,880	2,949	3,017	3,077	3,139	3,202	3,266	3,331	3,398	3,466
11	Vegetation management	2,944	3,029	3,102	3,173	3,236	3,069	3,130	3,193	3,257	3,322	3,388
12	Routine and corrective maintenance and inspection	3,635	4,743	4,860	5,015	5,465	5,315	5,423	5,557	6,172	5,744	6,034
13	Asset replacement and renewal	2,642	3,135	3,210	3,284	3,231	3,296	3,362	3,429	3,498	3,568	3,639
14	**Network Opex**	12,020	13,787	14,121	14,489	15,010	14,819	15,117	15,445	16,258	16,031	16,527
15	System operations and network support	4,374	4,873	5,126	5,246	5,354	5,463	5,575	5,689	5,805	5,923	6,044
16	Business support	13,581	16,443	17,036	17,149	16,814	17,168	17,633	17,886	18,245	18,622	18,770
17	**Non-network opex**	17,955	21,316	22,162	22,396	22,168	22,631	23,208	23,574	24,050	24,545	24,813
18	**Operational expenditure**	29,974	35,103	36,283	36,885	37,178	37,450	38,325	39,019	40,308	40,576	41,340

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799
23	Vegetation management	2,944	2,944	2,944	2,944	2,944	2,737	2,737	2,737	2,737	2,737	2,737
24	Routine and corrective maintenance and inspection	3,635	4,610	4,613	4,653	4,970	4,739	4,741	4,763	5,186	4,731	4,873
25	Asset replacement and renewal	2,642	3,047	3,047	3,047	2,939	2,939	2,939	2,939	2,939	2,939	2,939
26	**Network Opex**	12,020	13,399	13,402	13,442	13,652	13,214	13,215	13,237	13,661	13,206	13,347
27	System operations and network support	4,374	4,736	4,927	4,958	4,958	4,958	4,958	4,958	4,958	4,958	4,958
28	Business support	13,581	15,600	16,289	16,061	15,432	15,457	15,587	15,497	15,507	15,527	15,307
29	**Non-network opex**	17,955	20,336	21,216	21,020	20,390	20,415	20,545	20,455	20,465	20,485	20,265
30	**Operational expenditure**	29,974	33,735	34,618	34,461	34,042	33,629	33,761	33,692	34,126	33,691	33,613
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

38

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	81	150	218	278	340	403	467	532	599	667
43	Vegetation management	-	85	158	229	293	332	394	456	520	585	652
44	Routine and corrective maintenance and inspection	-	134	248	363	494	576	682	794	986	1,012	1,161
45	Asset replacement and renewal	-	88	164	237	292	357	423	490	559	629	700
46	**Network Opex**	-	389	720	1,048	1,358	1,605	1,902	2,208	2,597	2,825	3,179
47	System operations and network support	-	137	199	288	395	505	616	730	846	965	1,086
48	Business support	-	843	747	1,088	1,382	1,711	2,046	2,389	2,738	3,095	3,462
49	**Non-network opex**	-	980	945	1,376	1,777	2,216	2,663	3,119	3,585	4,060	4,548
50	**Operational expenditure**	-	1,369	1,665	2,423	3,136	3,821	4,565	5,327	6,182	6,885	7,728

Schedule 12a: report on asset condition

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.24%	0.51%	2.74%	8.72%	87.80%		3	1.01%
11	All	Overhead Line	Wood poles	No.	4.12%	8.24%	27.12%	28.24%	32.27%		3	20.26%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.95%	2.10%	9.20%	17.36%	70.38%		3	5.43%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0.00%	0.00%	0.01%	0.36%	99.63%		3	0.51%
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	3.98%	82.85%	13.17%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	98.87%	1.13%	0.00%		4	26.62%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-		4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	100.00%	-		4	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	4.76%	-	38.10%	52.38%	4.76%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-		4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	48.65%	21.62%	29.73%		4	21.62%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	16.95%	81.36%	1.69%		4	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	59.38%	40.63%	-		2	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	57.14%	38.86%	4.00%		2	
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-		4	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	57.89%	42.11%	-		2	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	6.37%	5.73%	6.37%	10.83%	70.70%		4	12.10%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							4	

36					Asset condition at start of planning period (percentage of units by grade)							
37	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.	-	4.88%	41.46%	34.15%	19.51%		4	16.33%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.64%	3.36%	7.85%	10.59%	75.57%		4	4.61%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km								
42	HV	Distribution Line	SWER conductor	km								
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.06%	0.16%	1.53%	10.74%	87.51%		3	0.36%
44	HV	Distribution Cable	Distribution UG PILC	km	0.08%	0.24%	2.22%	10.15%	87.31%		2	0.54%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	100.00%	-	-	-		3	100.00%
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	14.71%	44.12%	41.18%		4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.								
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6.34%	3.88%	11.84%	67.25%	10.69%		3	7.49%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							2	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.87%	5.74%	26.23%	42.62%	22.54%		4	14.75%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.34%	2.23%	6.57%	12.91%	76.95%		3	2.25%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.38%	2.70%	9.48%	11.85%	74.59%		3	3.69%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	16.67%	66.67%	16.67%		4	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	15.97%	10.92%	26.05%	44.54%	2.52%		4	46.67%
55	LV	LV Line	LV OH Conductor	km	0.68%	1.27%	4.35%	7.64%	86.06%		4	1.25%
56	LV	LV Cable	LV UG Cable	km	0.01%	0.02%	0.16%	1.11%	98.70%		2	0.05%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.00%	0.00%	0.08%	0.96%	98.96%		2	
58	LV	Connections	OH/UG consumer service connections	No.	-	-	0.01%	25.00%	74.99%		3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	10.32%	5.16%	45.63%	33.33%	5.56%		3	17.31%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-		4	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	95.83%	4.17%		4	-
62	All	Load Control	Centralised plant	Lot	66.67%	16.67%	16.67%	-	(0.00%)		4	33.33%
63	All	Load Control	Relays	No.	24.12%	1.37%	47.09%	26.31%	1.11%		3	-
64	All	Civils	Cable Tunnels	km								

Schedule 12b: report on forecast capacity

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP.
Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

8 *Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9 Alexander Street	10	15	N-1	10	66%	15	69%	No constraint within +5 years	
10 Bream Bay	6	10	N	3	55%	10	85%	No constraint within +5 years	
11 Dargaville	12	15	N-1	3	79%	15	84%	No constraint within +5 years	
12 Dargaville 110/50/66 kV	12	35	N-1	3	34%	35	84%	No constraint within +5 years	
13 Hikurangi	7	10	N-1	3	69%	10	73%	No constraint within +5 years	
14 Kaiwaka	3	5	N	3	50%	5	53%	No constraint within +5 years	
15 Kamo	13	15	N-1	4	84%	15	89%	No constraint within +5 years	
16 Kensington (Regional)	61	50	N-1	20	122%	100	65%	No constraint within +5 years	Transformer upgrade in FY25
17 Kioreroa	9	20	N-1	5	43%	20	43%	No constraint within +5 years	
18 Mangawhai	8	10	N	2	75%	10	58%	No constraint within +5 years	Load transferred to new Mangawhai Central Substation
19 Mareretu	3	5	N	2	51%	5	54%	No constraint within +5 years	
20 Maungatapere	5	8	N-1	6	72%	8	82%	No constraint within +5 years	
21 Maungatapere (Regional)	46	30	N-1	22	154%	60	70%	No constraint within +5 years	Transformer upgrade in FY26
22 Maungaturoto	7	8	N-1	2	88%	8	91%	No constraint within +5 years	
23 Maunu	4	10	N	4	35%	10	39%	No constraint within +5 years	
24 Ngunguru	3	5	N	1	55%	5	64%	No constraint within +5 years	
25 Onerahi	7	15	N-1 Switchable	3	48%	15	52%	No constraint within +5 years	
26 Parua Bay	3	5	N	2	70%	5	79%	No constraint within +5 years	
27 Poroti	3	5	N	3	61%	5	67%	No constraint within +5 years	
28 Ruakaka	8	10	N-1	4	83%	10	97%	No constraint within +5 years	
29 Ruawai	3	5	N	3	68%	5	72%	No constraint within +5 years	
30 Tikipunga	17	20	N-1	9	86%	20	93%	No constraint within +5 years	
31 Whangārei South	11	10	N-1	7	106%	10	112%	No constraint within +5 years	Transformer upgrade in FY32, 11 kV backfeed will maintain security

32 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c: report on forecast network demand

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 **12c(i): Consumer Connections**

8 *Number of ICPs connected in year by consumer type* — **Number of connections**

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11	*Consumer types defined by EDB**						
12	Very large industrial	-	-	-	-	-	-
13	Commercial and Industrial (demand based ND9)	5	5	5	5	5	5
14	Mass market	1,119	1,141	1,164	1,187	1,211	1,235
17	**Connections total**	1,124	1,146	1,169	1,192	1,216	1,240

18 **include additional rows if needed*

19 **Distributed generation**

sch ref							
20	Number of connections	329	350	371	392	413	434
21	Capacity of distributed generation installed in year (MVA)	2.80	2.90	3.10	3.30	3.50	3.70

22 **12c(ii) System Demand**

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
25	GXP demand	155	157	116	119	122	125
26	*plus* Distributed generation output at HV and above	10	10	54	54	54	54
27	**Maximum coincident system demand**	165	167	170	173	176	179
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	165	167	170	173	176	179
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	842	859	875	892	906	921
32	*less* Electricity exports to GXPs	-	-	264	264	264	264
33	*plus* Electricity supplied from distributed generation	21	21	284	284	284	284
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	863	880	895	912	926	941
36	*less* Total energy delivered to ICPs	816	841	855	871	885	898
37	**Losses**	47	40	40	41	42	42
38							
39	**Load factor**	60%	60%	60%	60%	60%	60%
40	**Loss ratio**	5.4%	4.5%	4.5%	4.5%	4.5%	4.5%

Schedule 12d: Report on forecast interruptions and duration

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	162.0	162.0	162.0	162.0	162.0	162.0
12	Class C (unplanned interruptions on the network)	93.0	93.0	93.0	93.0	93.0	93.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.72	0.72	0.72	0.72	0.72	0.72
15	Class C (unplanned interruptions on the network)	2.28	2.28	2.28	2.28	2.28	2.28

Schedule 13: Report on asset management maturity

Company Name	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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?	2.5	Asset Management Policy is approved by COO - Network and forms part of our controlled document (managed through our Quality Management System). It is an overarching policy which is intended to inform our asset management strategies, and be considered in investment decisions. We have recently updated our AM Policy and are developing our lower level documentation to ensure that our policy is embedded in every day asset management activities		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2.5	Our electricity network strategy, outlined in the AMP, has at its core delivering a consistent, safe and cost effective supply of electricity to our customers by using good asset management practices. The strategy gives effect to our shareholders' expectations (as set out in our SCI), as well as our risk management policy. We consider stakeholder feedback, including through informal and formal channels, in developing our strategy. Our common management systems are certified to ISO 9001, ISO 14001 and we have developed an asset management maturity roadmap to align our approach to ISO55001.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2.5	We have a documented asset management strategy with an approach aimed at managing the asset lifecycle of our assets. We have started to document individual asset class strategies. These will outline specific performance criteria that we will measure and monitor performance against.		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	Our asset management work plan is documented in broad terms within our AMP. Detailed work plans are documented in the annual work plan, project definition documents, detailed project scopes and in our preventative and corrective maintenance plans. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Our AMP is communicated through our intranet and published on our website. This is used as a key tool for communication with internal and external stakeholders. Work is underway to develop a formal asset management communications plan and roll it out.		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?	2	Overall responsibility of delivery of the AMP is resides with the COO - Network and roles are further defined in Chapter 2 of the AMP. The Delegated Authorities Policy outlines financial authorities for the AMP delivery programme. Further work is underway to develop a RASCI analysis for the activities in the AMP.		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)	2	There is a formal service level agreement (SLA) in place with our principal contractor. A robust governance structure is in place with monthly reporting on progress against plans. Supplier arrangements are in place for key equipment and materials. Competitive commercial processes relating to procurement for large projects and critical network assets are well established. Further work is underway to review our delivery capability against our AMP work 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. 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	Northpower has well documented emergency and incident response procedures, including: a Co-ordinated Incident Management Plan for major events impacting network operations; a suite of network contingency plans used to assist in major unplanned events that significantly disrupt supply; a revised Business Continuity plan and processes for events which disrupt business operations. We are an active member of the Northland Lifelines group and the regional CDEM group. We regularly review and update our contingency and disaster recovery plans to ensure they remain relevant and appropriate. We have adequate staff and contractor resources available for events (via the wider Northpower Group), standby generators available, a backup control centre at a remote location. Most staff can work remotely if required.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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)?	2	The COO - Network is responsible for delivering the requirements of the asset management strategy, objectives and plans. In turn, responsibilities are delegated to members of the network leadership team. These responsibilities are supported by a delegated authorities policy, with clearly defined levels of financial authority. Most delivery activities are contracted out to experienced field service providers, and governed through service level agreements that define accountabilities and responsibilities. Some work is underway to ensure that roles and responsibilities are clearly defined		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?	1.5	Management oversight at an Executive level monitors achievement of asset management activities. This includes reporting on key metrics, including delivery and performance, and these are also reported to the Board monthly. There is a process for establishing the need for additional employees for internal resourcing. We are developing more detailed resourcing forecasts to ensure that we have the resources to deliver our AMP work programme.		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?	2	A range of strategies are employed to communicate the importance of meeting asset management requirements. This includes monthly reporting against performance targets, weekly meetings with senior leadership teams to discuss asset management requirements and ensure we are on plan, regular meetings with our delivery contractor at which asset management requirements are discussed. Key deliverables and progress against plan, as well as core asset management issues are communicated at regular all team meetings. We are developing a communications plan to ensure that key messages are being communicated effectively		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.5	Compliance is ensured by service level agreement (SLA) and contracts for field services and construction works. The majority of outsourced work is undertaken by Northpower Contracting under a SLA which outlines respective responsibilities and KPI's to support performance. Control processes include formal project specifications and documentation, HSQE audits. Project managers are accountable for ensuring compliant delivery of outsourced activities. The Contracts and Services Manager is accountable for assessing performance of contractors under the relevant agreements. We are working on ensuring our contracts and processes are robust for all external contractors.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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)?	2	Department managers identify human resource requirements. Key competencies are documented in job profiles and competence is assessed during performance reviews. We have training budgets allocated and each employee is encouraged to have a personal development plan. We have invested in the training of engineering cadets to meet future resourcing requirements. Staff over the past five years have been scaled up to reflect our commitments to lift our asset management approach and work load. We recognise that additional resourcing is likely required to meet asset delivery plans and have developed approved contractor frameworks to enable additional contractors on the network. Work is underway to develop a competency framework to ensure that we can meet our asset management objectives.		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?	2	As per question 48 above. Competencies are identified in the job design process, and included in position descriptions. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Competencies are defined for certain field based activities, and managed through our Learning Management System (this includes records of learning and verifications). Specialised training is provided for control operators. Staff or contractors not holding the mandatory competencies are unable to undertake the associated activities. Asset management specific competency requirements and training is currently being developed.		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?	2	Service provider training and competence is managed through established competency frameworks. These are subject to regular audit. Asset management skills and competencies are documented in job descriptions and reviewed during annual performance reviews. Staff are encouraged to have a personal development plan and development and training opportunities are discussed with each employee. Staff are expected to attend relevant courses or seminars to upskill as needed. Staff new to the industry are assisted with their development by exposure to engineering projects and related tasks under the guidance of senior staff. Asset management specific competency requirements and training is currently being worked through		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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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?	2	Publication and availability of the AMP on our website, relevant information is included in customer newsletters and other channels such as social media; quarterly updates are provided to the shareholder. The contractor has access to asset information and reports through GIS and WASP. Technical and operational standards are available to contractors through our QMS system, with some key documents also externally available through our website. (e.g.: policies that help define asset ownership, standards to assist designers of subtransmission and distribution assets, network planning standards and asset fleet strategies). We have established a technical advisory team within the customer services team to assist external stakeholders to understand key network and asset management requirements. We are developing a communications plan to ensure we communicate the right information to our stakeholders.		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?	1.5	We have in place some of the key elements of an asset management system - documented in our asset management policy, our AMP, our asset strategies, and our network standards framework and documents. We are in the process of developing our asset management documentation suite (set out in Chapter 4).		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	We have developed an asset information strategy and are in the process of documenting our current and future data capture rules in data standards. These standards are published in the quality management system and define data capture rules for each asset class. As we develop our asset modelling we will further improve our asset data capture requirements. Asset data is mastered in the GIS and made available to users via a range of viewers and analysis software. Asset history including corrective maintenance, tests and inspections, is stored in the works management system. This data is used to support operations, maintenance and replacement. Two major strategic initiatives, an upgrade of the AMIS and implementation of a DMS, are expected to result in further changes to data requirements.		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?	1.5	Our asset information team maintain asset information in various systems - primarily our GIS and WASP system. They take steps to ensure data quality and accuracy and look for areas where to improve this. Data quality is continuously improved by way of ongoing field capture, sample audits and data analysis. We are in the process of gaining more visibility of our data quality and gaps to improve our accuracy over time.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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Question No.	Function	Question	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?	1.5	The pairing of GIS as the core system of record for asset data and EMS WASP for works management and asset history have supported asset management functions to date. However we recognise that understanding asset condition and performance as well as managing defect information and supporting root cause analysis. This will require further improvements in the capability of the information systems used to support asset management. We recognise that we must continue to meet growing stakeholder expectations of asset information including regulatory, customers, shareholders, landowners, service providers and asset managers. We are in the process of ensuring our data capture requirements are relevant to our needs		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	Chapter 7 details the overall approach to risk, systems utilised, documents and risk management plans. We regularly review our key risks and improvement actions. We have an audited safety management system (SMS) in accordance with NZS 7901. ISO 9001 and ISO 14001 also used to identify risks. We undertake post incident reviews to ensure lessons learned and continuous improvement. Actions arising from incidents are logged and tracked in our QPulse system. Asset risk is managed through documented procedures including inspection and maintenance standards. We are building a better understanding of our asset risks through the development of asset health and criticality modelling		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Risks are identified and mitigated, and controls are linked to resourcing, competencies, and training plans. Investment plans are built up based on known asset risks. Our new learning management system manages competencies, and we engage regularly with our field service providers to ensure the right levels of competencies are held and maintained for staff working on the network. Where risks or incidents have identified competencies and/or training improvements are required, these are followed up on. We are developing an asset management competency framework to ensure that we have the right competencies in the team to manage risk.		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	We have a legal compliance programme, which includes a register of all material obligations and regular surveys run through Comply With, where all responsible persons are required to attest to the state of compliance in their business area. Results are reviewed by the executive and reported to the Audit and Risk Committee. In house legal counsel support with advice on legal and compliance issues. The Network Commercial and Regulatory Manager is responsible for oversight of regulatory compliance obligations. The AMP is reviewed by leadership team and an external specialist assesses compliance to support director certification. Staff have clear PDs and understand their area of responsibilities and authority.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	The AMP includes an annual programs of capital and operations activities. Approved annual capital and maintenance budgets reflect operational plans for programs of work (such as asset inspection, maintenance and asset renewals) and project works, such as power transformer replacements and upgrades. Work is overseen by the delivery team, and includes dedicated project managers. Work is issued to the field service providers and the program of works is governed by the SLA or other relevant contracts. Network standards and procedures define the requirements for design, equipment procurement, construction, commissioning, operation and ongoing inspection and maintenance. Our processes and documentation are being refined in some areas		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?	1.5	There are defined processes for inspections, recording defects and maintenance and other work on assets. We have refined some of these to provide better clarity on the classification of defects. We have defined timeframes for when each category of defect needs to be remediated. Progress against defect remediation is closely monitored and we continue to review our systems for areas for improvement. We audit the quality of work performance by our service providers. Our SLAs define clearly the requirements to be delivered. We are currently reviewing our asset lifecycle activities to ensure they are consistent with our asset management strategy and control cost, risk and performance as we develop our asset class strategies.		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?	1.5	Asset performances is monitored via reliability reporting, inspections, unplanned outages, major weather events and incidents. We are developing asset strategies which for major fleets define performance requirements across safety, reliability, cost and environment. We plan to further develop reporting across these metrics. Investigations are conducted for major asset failures to identify improvement opportunities. Debriefs are held following weather events and other incidents to identify improvement opportunities for asset selection, configuration and operational response. We are refining asset class strategies, asset modelling and data requirements.		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?	2	Requirements for reporting and handling of incidents, emergencies and non-conformances is outlined in written procedures and standards. Some are groupwide (e.g. Health and Safety Incident reporting), others are network specific (e.g. outage reporting, incident management plan). Responsibilities are outlined in those documents, as well as in the objectives and duties of the relevant staff. A companywide reporting system (NPSAFE) is used to report and follow up on HSQE incidents. Outages are reported in the faults Database, and results and trends monitored and reported monthly. Serious incidents are subject to ICAM investigation, either by internal staff or an independent investigator. QPulse is used to capture actions and non conformances to monitor progress of assigned actions. The leadership team undertakes weekly reviews of incidents and actions. Findings from investigations are shared across the organisation and other EDBs where warranted. We are improving our event management process and part of this will ensure clarity of responsibilities and authorities.		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	**Northpower**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1	We are certified to ISO9001:2015 which supports our quality management system. We are also certified to ISO14001:2015 for our Environmental Management System, and ASNZS 4801 for our Health and Safety Management System, and NZS 7901 Electricity and Gas Industries - Safety Management System for Public Safety. We undertake regular internal audits against these systems. HSQE audits are undertaken by staff to ensure contractors are delivering to our requirements. An area for improvement is to systemise audits of other key asset management processes. We are working on expanding our asset management framework and will ensure that an audit process is established to cover our entire asset management system.		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?	1.5	Our corrective action processes are actively managed through normal business activities, roles and responsibilities and contractor management process. The outage review process investigates significant outages and equipment failure events. The incident review process is used to investigate what defences failed and recommended corrective or improvement actions. All staff and contractors are aware that they must report all incidents and non-conformances. We are improving our event management process, part of this will ensure that corrective/preventive are clearly captured and followed through to delivery.		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?	1.5	We have some feedback loops to inform our continual improvement requirements and are in the process of improving our event management processes to ensure that continuous improvement is embedded in our operating model and part of BAU. Current improvements are identified through our business planning process and delivered through structured projects or programmes. We have set up delivery governance and investment governance committees to oversee our asset management processes to drive improvement.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	We source improvement information from several sources, both internal and external, including - equipment suppliers - Industry partners, including EDBS and the EEA, industry conferences, forums and trade shows. - engagement of consultants - Learnings from our field service provider, which is one of the largest electricity supply contractors in NZ, and works for a number of other network companies. Our staff participate in a range of industry groups and conferences, on issues topical to the management of our assets and the integration of new technologies. Testing of materials takes place 'in the field'. And is reported on. We are in the process of setting up some more formal processes and roles to ensure innovation is embedded in our business.		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 and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between constant and nominal prices is based on the New Zealand Institute of Economic Research (NZIER) June 22 consensus forecast through to FY26, after which it is based on an escalation of 2%.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

APPENDIX C. FURTHER NETWORK DETAILS

Summary of Key Investments

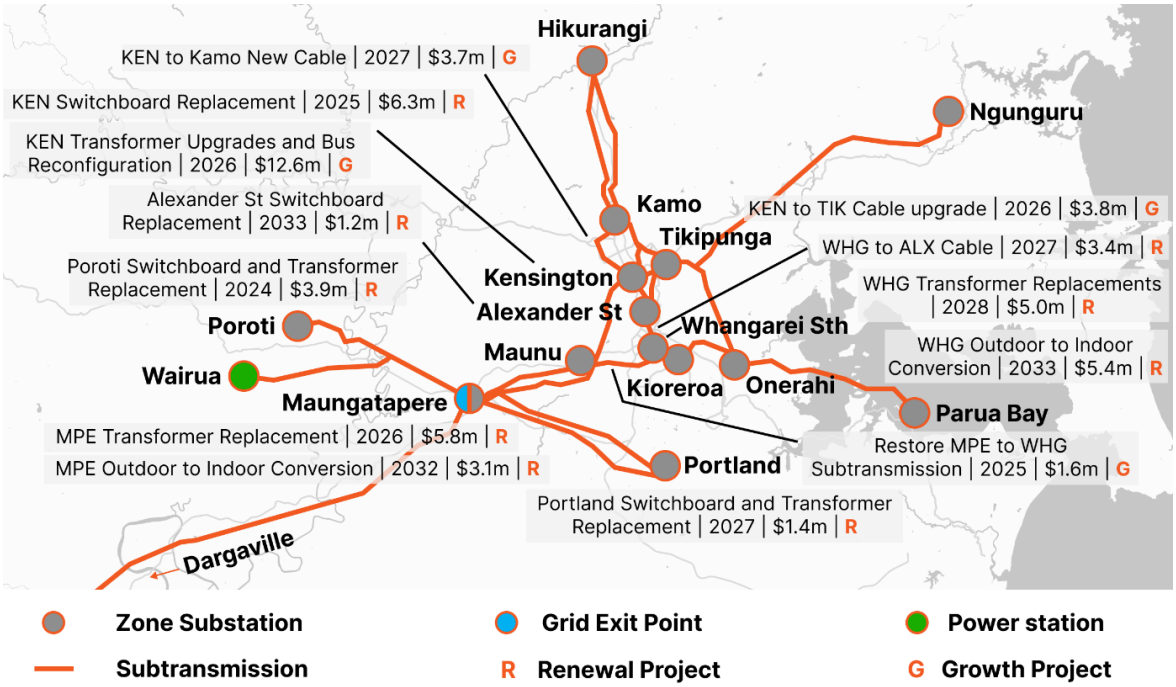
This section summarises the key investments on the network over the planning period, FY24-33, by the areas supplied from each GXP.

> **Scale of cyclone damage yet to be fully quantified**
>
> As discussed elsewhere, at the time of publishing this AMP we had not undertaken any material analysis of renewal and network remediation need beyond that required to restore customer service.
>
> We need to understand the condition of our network following this event and may need to rebuild certain parts of the network to restore a sustainable level of network condition. We are beginning to develop these plans and will include the required investments in future disclosures.

Maungatapere GXP

The below map shows the key investments in the areas supplied by Maungatapere GXP.

Maungatapere GXP key investments

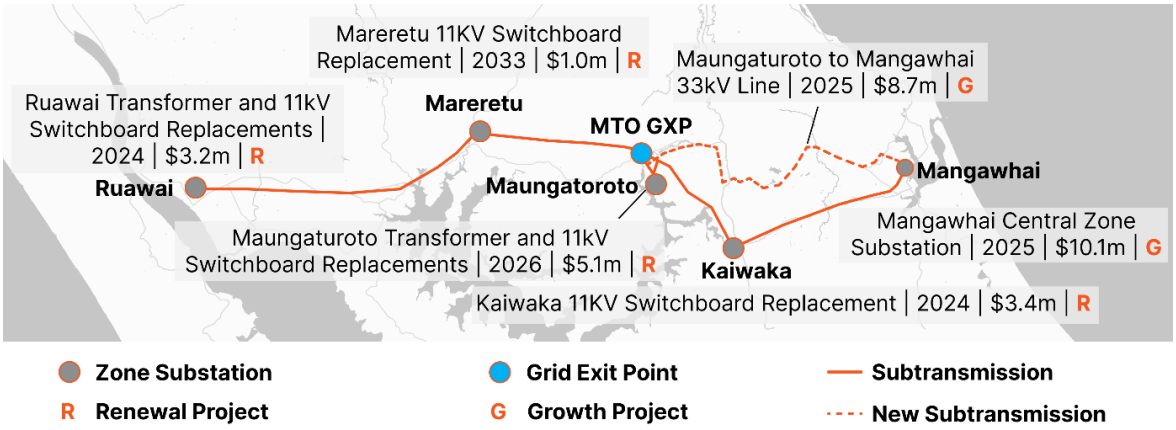


There are a number of projects being carried out on this part of the network over the planning period. Some of the larger investments include the Kensington upgrade which involves new transformers, switchboard, and bus configuration, and the MPE transformer replacement project. Other projects include end-of-life renewals and upgrades to enable load growth and improve security.

Maungaturoto GXP

The below map shows the key investments in the areas supplied by Maungaturoto GXP.

Maungaturoto GXP key investments

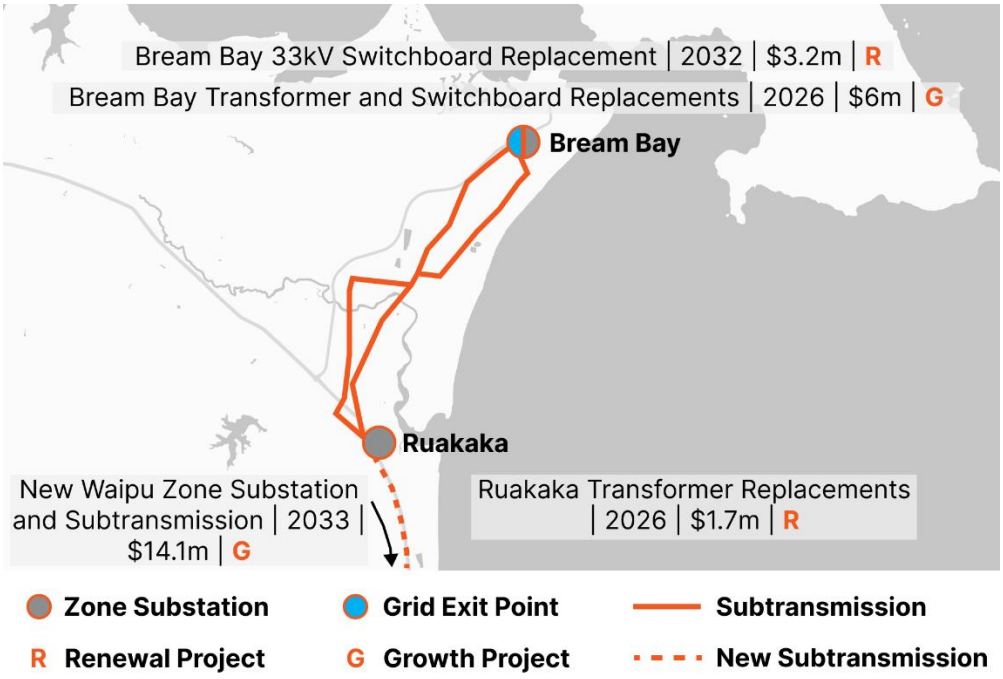


The significant expenditure in this region includes a new substation at Mangawhai and the new line between Mangawhai and this substation. We are also undertaking some renewal investments at other zone substations in the area where assets have reached end of life.

Bream Bay GXP

The below map shows the key investments in the areas supplied by Bream Bay GXP.

Bream Bay GXP key investments



The most significant project in this region over the planning period is the new Waipu zone substation and the subtransmission line from Ruakākā to this new zone substation. We also

have some replacements and upgrades planned at the Bream Bay zone substation to allow for growth in the area.

Zone substation investments and overview

This section covers some of the key information about each zone substation and the investments covered over the planning period.

Bream Bay zone substation

Substation overview

This substation supplies a mixture of industrial, commercial, and residential load. The potential for growth in the surrounding area is very high, with the district council designating large areas of land for heavy industry, service industry, and residential development.

The present 11kV load is increasing and is expected to increase substantially in the medium to long term due to the development of the deep-water port at Marsden Point, a newly established marina in the One Tree Point area, and other developments.

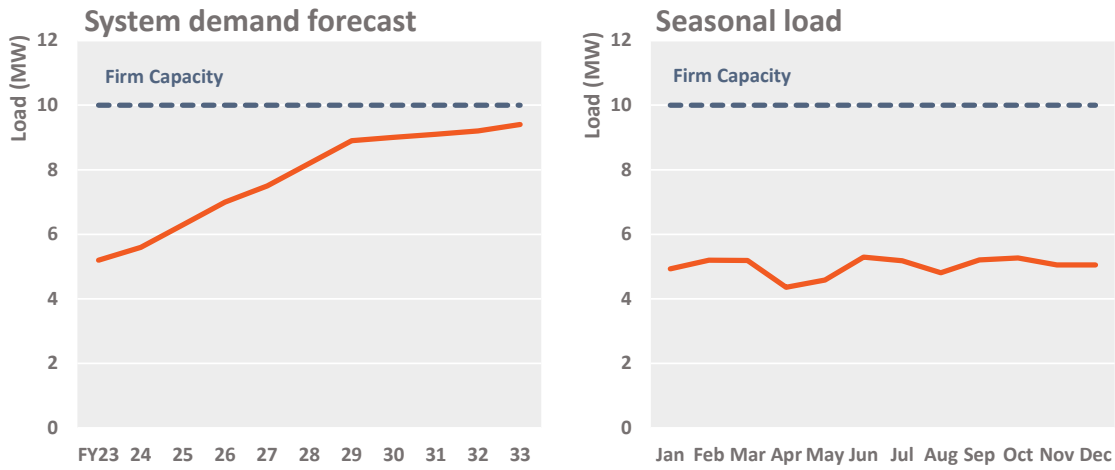
Installation of a second transformer is planned for the future (FY24–FY26) to increase security of supply as the load grows. The need for and timing of a second transformer will be taken into consideration including the 10MW peak lopping generation plant (connected to the station's 11kV bus) operated by an energy company, as this plant could be used for back-feeding purposes. An 11kV conductor upgrade project is currently underway to relieve a distribution constraint. Once completed, this will also allow for future load growth and improve 11kV feeder back-feed capability. The existing 11kV switchgear is planned for upgrade from FY24 to FY26.

Bream Bay zone substation technical summary

BREAM BAY ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 7.5MVA ONAN/10MVA OFAF	
Peak load			5MW	
Total number of customers supplied			1,603	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Marsden Bay	1,107	1,496	Overhead	Residential
Port Feeder	1,110	7	Underground	Industrial
Marsden South	1,111	100	Overhead	Residential/Commercial mix

Substation demand

Bream Bay zone substation forecast system demand and seasonal load

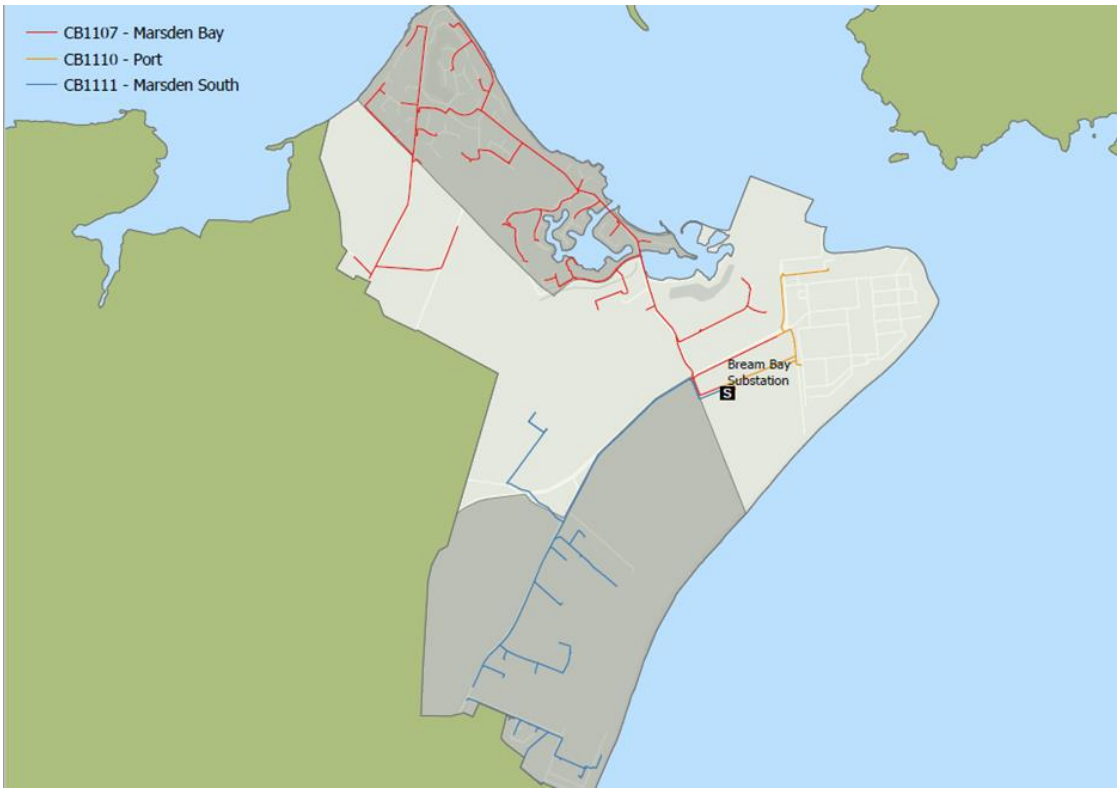


Forecast capital investment

Bream Bay zone substation key capex projects

GROWTH PROJECTS	TIMING
Bream Bay T2 and 11kV switchgear upgrade This project will install an additional 15/23MVA transformer to provide N-1 security to Bream Bay zone substation and meet growing demand. In conjunction, the existing 11kV switchboard will be upgraded.	FY24-26
RENEWAL PROJECTS	**TIMING**
Bream Bay 33kV switchboard replacement The project will replace a ~40-year-old switchboard which contains 12 CBs. The switchboard is a known arc flash hazard and lacks arc containment, which makes it unsafe for our staff to operate live.	FY30-32

Figure C.5: Bream Bay zone substation feeder map



Ruakākā zone substation

Substation overview

This substation is centred around the Ruakākā township and also supplies the surrounding rural dairying area, Waipu township, and the south-east coast holiday resort area. The rural area is becoming more lifestyle in nature and significant subdivision activity and growth is expected in the future. The switchboard incorporates a spare feeder for the anticipated future growth. In FY25–FY26 we plan on replacing transformer No.2 due to its condition. A project to increase the capacity of Marsden Point CB1 by offloading customers onto One Tree Point CB6 is planned for FY24.

A voltage regulator was installed on the Waipu feeder in 2016 to support the growing load in the area. We have recently identified an approaching capacity constraint for this regulator, and a feeder reconfiguration has been completed that has deferred this constraint. Another benefit from the feeder reconfiguration will be providing additional back-feed capacity to the Mangawhai substation.

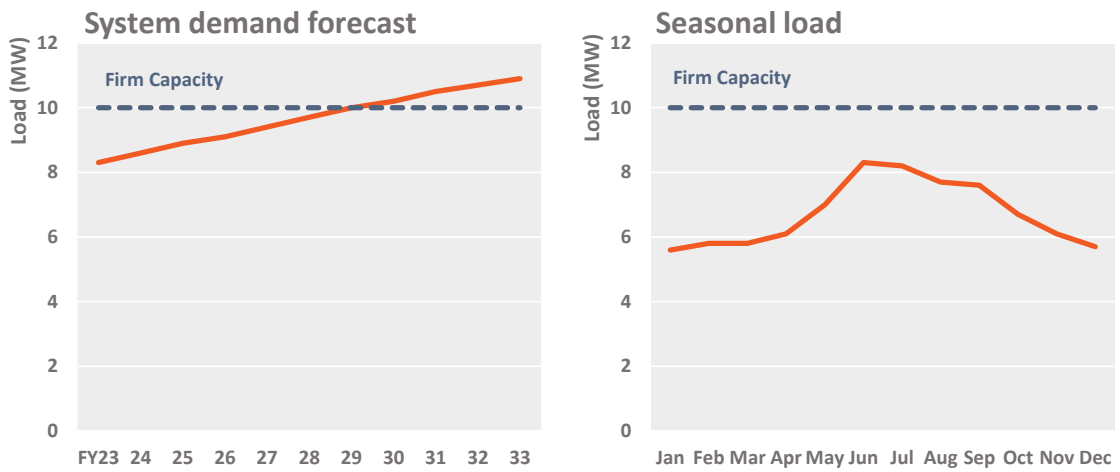
We have identified the need for a future zone substation in the Waipu area. The timing of this substation will allow for future anticipated load growth and development. This substation will also improve supply resilience in the area and provide greater backstop capability to Mangawhai and Ruakākā substations. Currently the substation is forecasted in FY31–FY33 and the 33kV line to supply the new substation is forecasted in FY29–FY31.

Ruakākā zone substation technical summary

RUAKĀKĀ ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 10MVA	
Peak load			8MW	
Total number of customers supplied			4230	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Marsden Pt	1	1,369	Overhead	Residential
Waipu	2	947	Overhead	Residential
Mata	3	433	Overhead	Residential
One Tree Point	6	389	Overhead	Residential
North River	7	1092	Overhead	Residential

Substation demand

Ruakākā zone substation forecast system demand and seasonal load



Forecast capital investment

Ruakākā zone substation key capex projects

GROWTH PROJECTS	TIMING
Ruakākā CB2 reconfiguration The project will install a new 3MVA voltage regulator and associated equipment and feeder reconfiguration to allow for additional back-feed capacity to the Waipu feeder. The reconfiguration will transfer around 240 customers from RKACB2 (Waipu feeder) to RKACB7 to provide full back-feed capacity. This will also provide RKA CB2 additional back feed to the Mangawhai substation.	FY25-26

RENEWAL PROJECTS	TIMING
Ruakākā T2 replacement Replacement of a 10MVA transformer which is in relatively poor condition. The transformer has relatively low paper degree of polymerisation (DP) readings, ranging from 200 to 500[41]. The transformer also has poor insulation resistance readings.	FY25-26

Ruakākā zone substation feeder map

Dargaville zone substation

Substation overview

A major reconfiguration of the 11kV feeders at this station was completed in 2015 to remove a double circuit line running through Dargaville township, and which optimised the 11 kV feeder loading.

This substation supplies a large rural area (mainly dairy farming) centred around Dargaville township. The meat works on the outskirts of the town and a sawmill to the north form the only significant industrial loads. Load growth has historically been very low, although there is a small amount of seasonal growth due to subdivision activity along the west coast, north of Dargaville.

41 A DP reading of 200 would warrant urgent replacement.

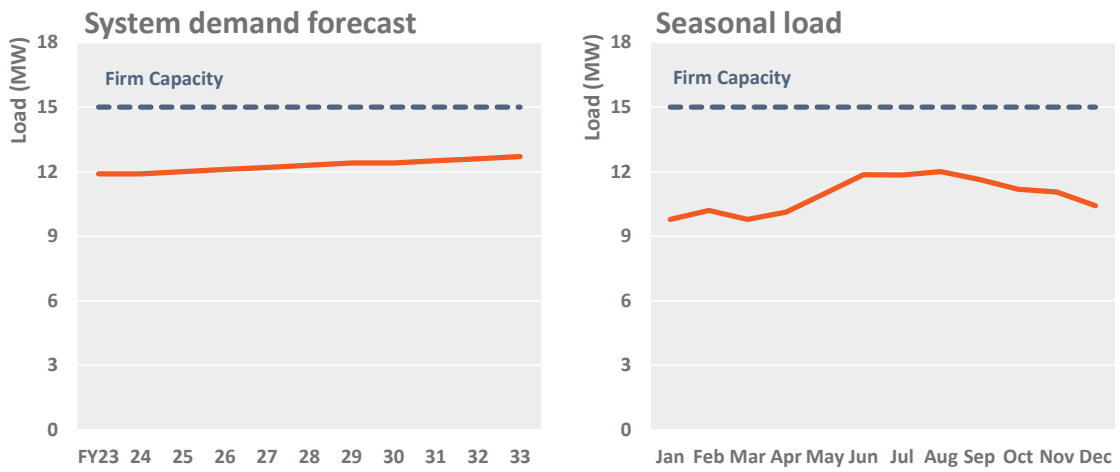
The mostly likely sector for significant future load growth is forestry, as the large plantations to the north of Dargaville mature. The growth in the medium to longer term is expected to be low. The area has attracted some interest for large DER connected to the network. In FY24 a new tie point between Dargaville CB4 and Dargaville CB8 is planned to increase the security of supply to the Dargaville CB4.

Dargaville zone substation technical summary

DARGAVILLE ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 7.5MVA ONAN/15 MVA OFAF	
Peak load			12MW	
Total number of customers supplied			5,926	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
North Dargaville	1	606	Overhead	Residential/Commercial mix
Te Kōpuru	2	931	Overhead	Residential
Town Dargaville	3	896	Overhead	Residential/Commercial mix
Awakino Point	4	375	Overhead	Residential
Coast	6	989	Overhead	Residential
Hokianga Rd	7	1,047	Overhead	Residential
Tangowahine	8	579	Overhead	Residential/Commercial mix
Turiwiri	9	503	Overhead	Residential/Commercial mix

Substation demand

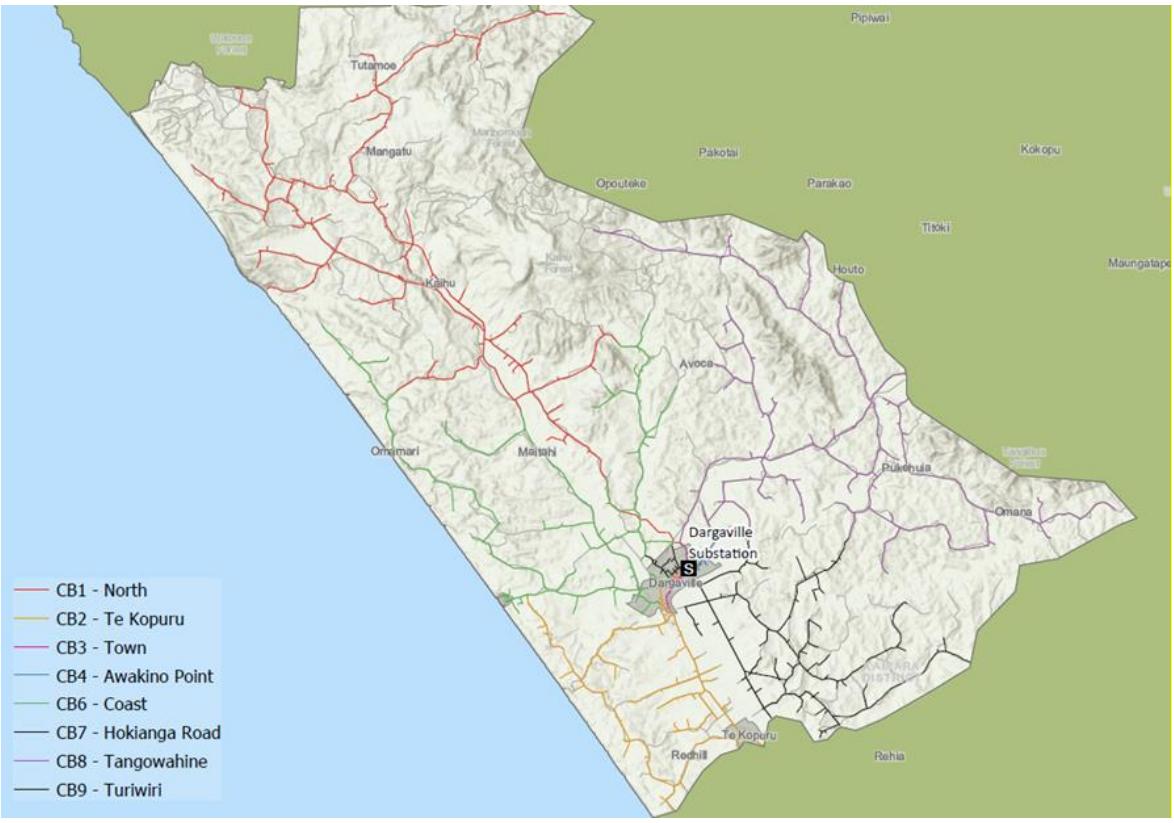
Dargaville zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Dargaville at this time

Dargaville zone substation feeder map



Alexander Street zone substation

Substation overview

This substation supplies the Whangārei city CBD and the central residential areas. The substation is supplied directly from Kensington 110/33kV regional substation.

The long-term load growth in the area is expected to be moderate, as the CBD area is almost fully developed. Business expansion taking place in Whangārei tends to be outside the current CBD area and a number of businesses have also relocated away from the central commercial area.

Some residential load was transferred from this station to the new Maunu substation, thus delaying the need to upgrade the transformers in the current 10-year planning horizon. The Maunu substation was constructed to address the growing needs in Maunu and provide contingency supply to Alexander Street, Whangārei South, and Maungatapere zone substations. The 33kV switchboard is scheduled for replacement in FY32–FY33 due to age.

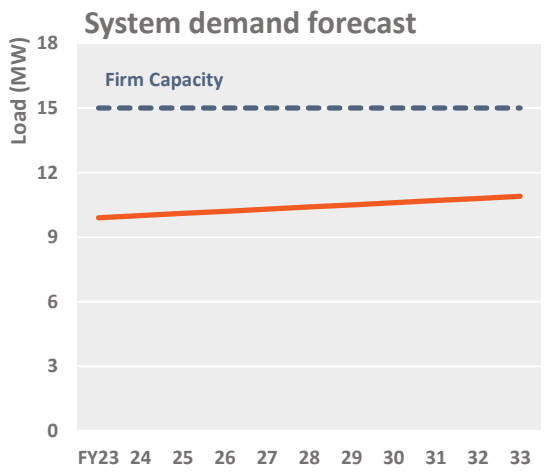
Alexander Street substation is an important backstop for any contingency at Whangārei South or Tikipunga substations. Alexander Street substation is fully restorable through the 11kV network.

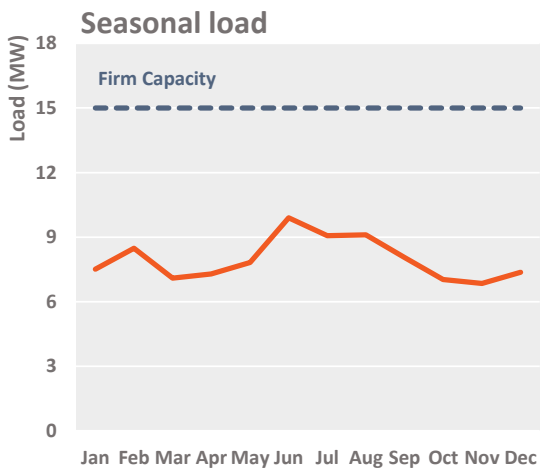
Alexander Street zone substation technical summary

ALEXANDER STREET ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 7.5MVA ONAN/15 MVA OFAF	
Peak load			10MW	
Total number of customers supplied			4,398	
FEEDER	CB	ICPs	LINES	CUSTOMER TYPE
Norfolk St	1	846	Underground	Residential
Forum North	2	406	Underground	Residential/Commercial mix
Second Ave	3	1,026	Underground	Residential
Bank of NZ	6	463	Underground	Residential/Commercial mix
Western Hills Dr	7	890	Overhead	Residential
Kensington	8	767	Overhead	Residential

Substation demand

Alexander Street zone substation forecast system demand and seasonal load





Forecast capital investment

Alexander Street zone substation key capex projects

RENEWAL PROJECTS	TIMING
Alexander Street 33kV switchboard replacement Replacement of ~35-year-old switchboard which contains 5 CBs. The switchboard has relatively high arc flash hazards and lacks spare parts for maintenance as the switchgear is now obsolete.	FY32-33

Alexander street zone substation feeder map

Hikurangi zone substation

Substation overview

The mainly dairy farming rural load surrounding Hikurangi township dominates the area supplied by this substation, although there is also some industrial load in the town. The substation also supplies a large flood-pumping scheme in the Hikurangi swamp area (occasional operation) as well as the coastal resort areas along the east coast as far north as Bland Bay.

The most likely prospect for growth is lifestyle sections and holiday resort development in the scenic east coast area. Hikurangi town itself could also see development as an overflow from Whangārei. To date, most of the coastal growth has been south of Whangārei and, to

a lesser extent, in the Tutukaka area. As these areas become more populated it is expected that the demand for coastal properties north of Whangārei will increase.

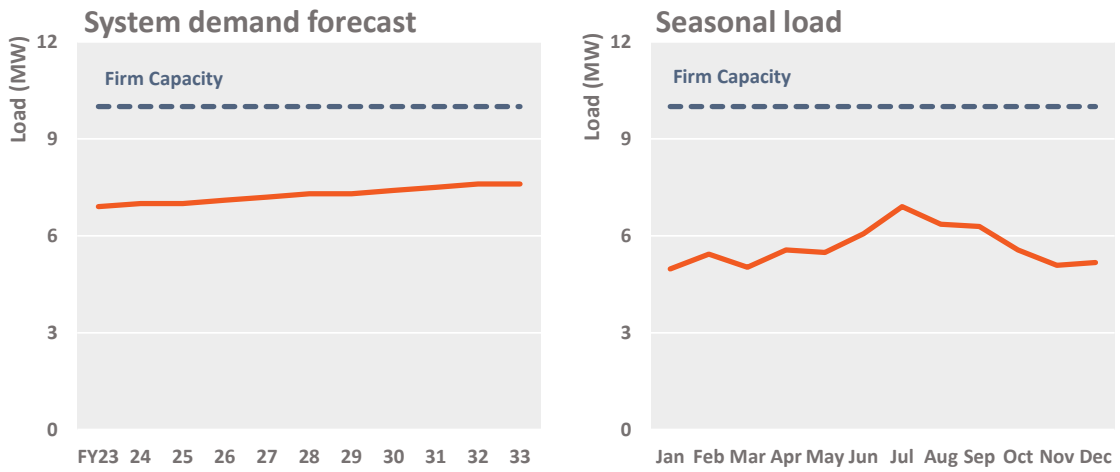
Load growth in the short to medium term is likely to be moderate but could increase in the longer term alongside growth in Whangārei. We have plans in place to upgrade and strengthen the 11kV network feeding the Helena Bay, Oakura, and Bland Bay areas. This will go ahead when the capacity of the existing network needs to be increased. The transformers were replaced with two 10MVA units in 2021, as well as the 11kV switchboard, thus providing capacity for the area for the foreseeable future.

Hikurangi zone substation technical summary

HIKURANGI ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 7.5MVA ONAN/10MVA OFAF	
Peak load			5MW	
Total number of customers supplied			1,603	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Whakapara	1,112	1,075	Overhead	Residential
Town Hikurangi	1,082	539	Overhead	Residential
Jordan Valley	1,102	468	Overhead	Industrial
Swamp South	1,092	22	Overhead	Residential/Commercial mix
Otonga	1,032	583	Overhead	Residential
Marua	1,022	308	Overhead	Residential
Swamp North	1,042	400	Overhead	Residential/Commercial mix

Substation demand

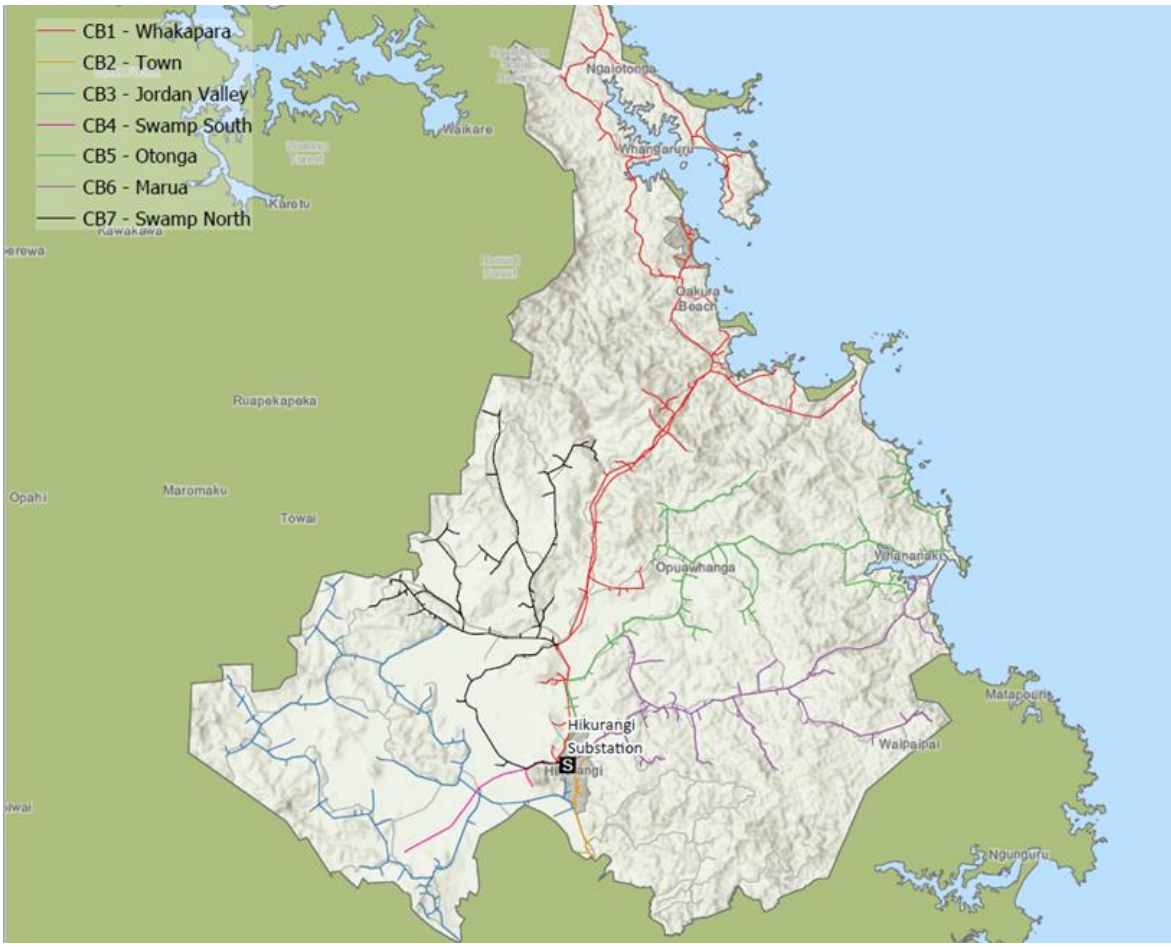
Hikurangi zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Hikurangi at this time.

Hikurangi zone substation feeder map



Kamo zone substation

Substation overview

Located on the northern boundary of Whangārei city, this substation supplies a mixture of industrial, commercial, residential, and rural load.

The industrial and commercial load is minimal, with the main growth occurring in the residential segment through a large number of lifestyle blocks and new residential developments. This trend is likely to continue. with planned development to the west. A relatively high growth rate can be expected over the next five to 10 years. Associated moderate commercial and light industrial load growth is also expected.

Due to the high growth rate of residential subdivisions in Kamo East, we have a feeder reconfiguration upgrade, to address a feeder network constraint, programmed in FY24.

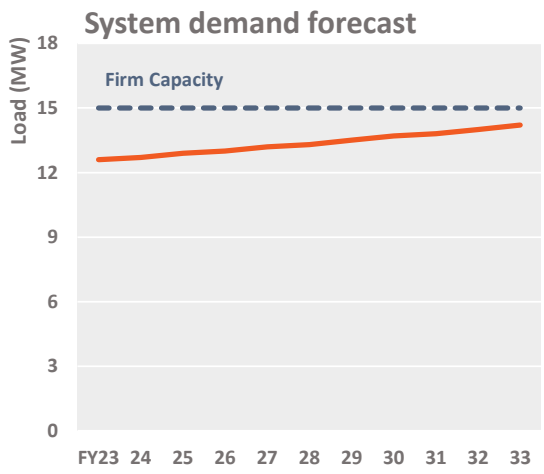
The 15MVA firm capacity at Kamo substation is adequate for the medium to long term. The 11kV switchboard upgrade was completed in 2011 and a new 11kV feeder was commissioned in 2015 to offload the Three Mile Bush feeder and reconfigure two other feeders to allow for load growth.

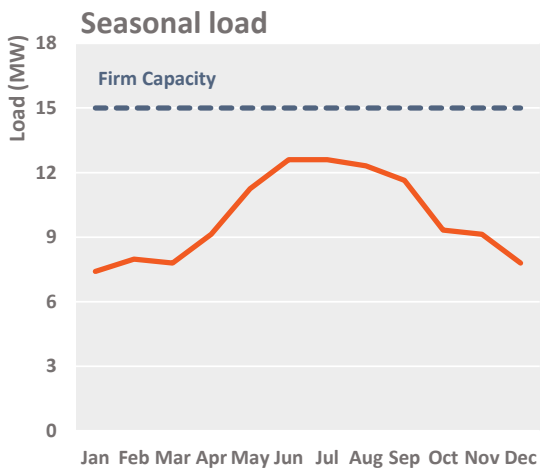
Kamo zone substation technical summary

KAMO ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 7.5MVA ONAN/15 MVA OFAF	
Peak load			13MW	
Total number of customers supplied			5,862	
FEEDERS	CB	ICPs	LINES	CUSTOMER TYPE
Springs Flat	1	654	Overhead	Residential
Charles St	2	1,660	Overhead	Residential
Three Mile Bush	3	870	Overhead	Residential
Ruatangata	6	736	Overhead	Residential
Kamo Town	7	697	Overhead	Residential
Ōnoke	8	1,245	Overhead	Residential

Substation demand

Kamo zone substation forecast system demand and seasonal load

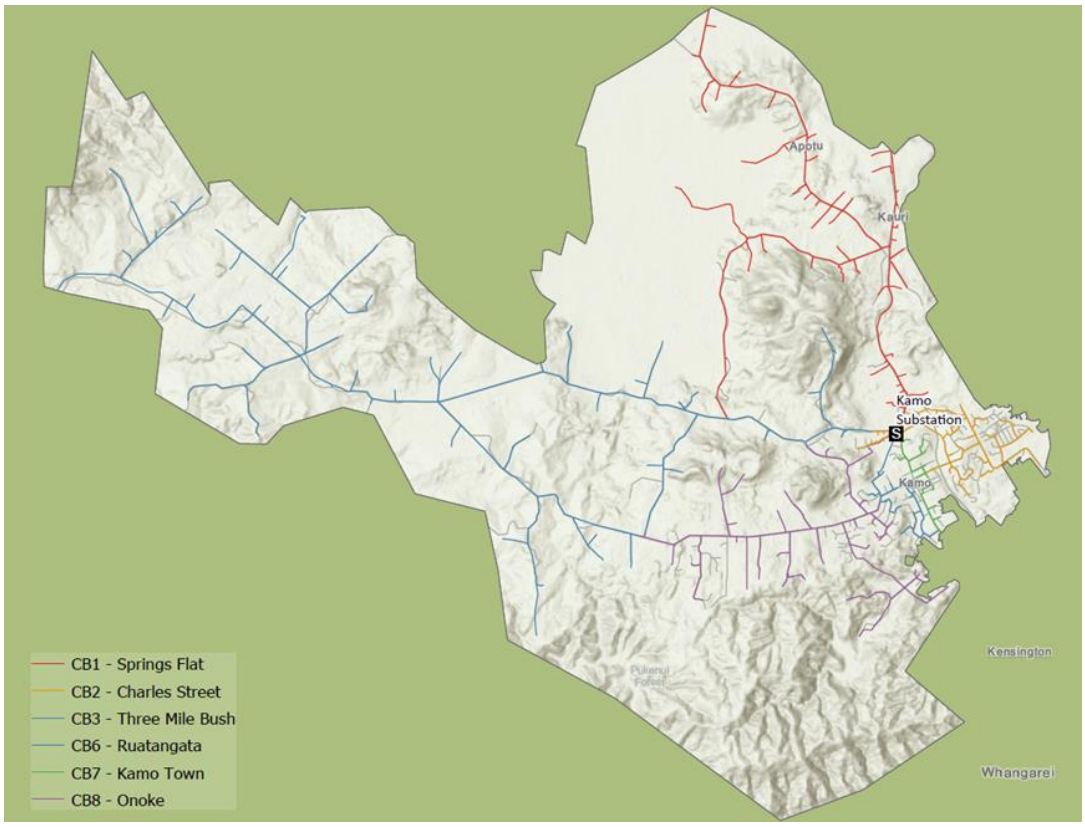




Forecast capital investment

No capital investment is forecast at Kamo at this time.

Kamo Zone Substation feeder map



Ngunguru zone substation

Substation overview

This substation supplies the Ngunguru township, Tutukaka, and Matapouri areas, made up mainly of residential load. Load growth has been fairly low; however, there is potential for significant development. The 3.75MVA transformer was replaced with a 5MVA unit in 2021 as it was reaching end of life. At the same time, the 11kV switchboard was replaced. The new transformer will have enough capacity to meet growth for the foreseeable future. Ngunguru has relatively low restorability due to the remote and coastal location.

We have identified a potential 11kV reinforcement upgrade that would allow for stronger backstopping to the area. This project has been included in the plan for completion in FY25–FY26.

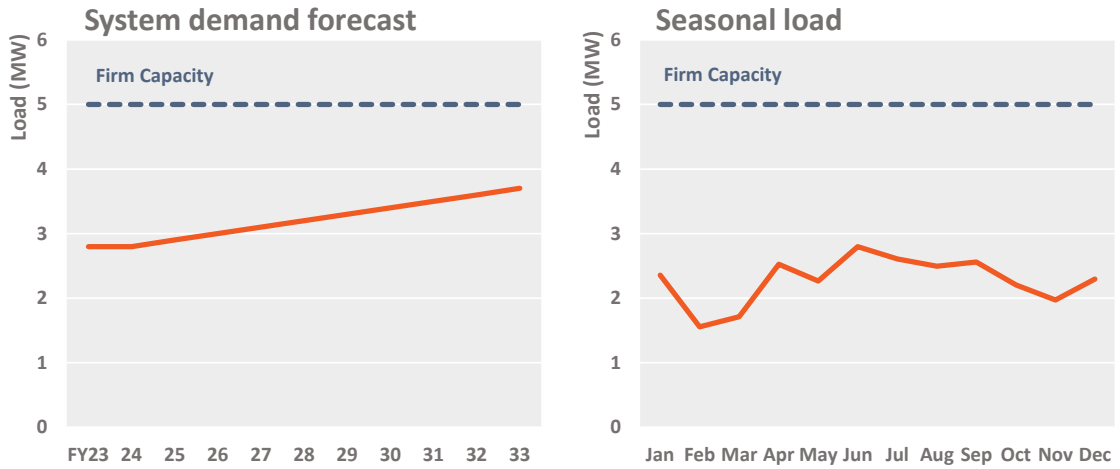
Ngunguru zone substation profile summary

NGUNGURU ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 5MVA	
Peak load			3MW	
Total number of customers supplied			2,087	
FEEDER	CB	ICPS	LINES	CUSTOMER
Tutukaka Block	1,082	641	Overhead	Residential

Kaiatea	1,072	677	Overhead	Residential
Matapouri	1,032	769	Overhead	Residential

Substation demand

Ngunguru zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Ngunguru at this time.

Ngunguru zone substation feeder map

Onerahi zone substation

Substation overview

This substation supplies the suburb of Onerahi (mainly residential with some commercial load) and the 11kV network also stretches out to the residential areas of Tamaterau, Manganese Point, and part of Riverside. There is a moderate amount of residential development in the area supplied from this substation and this is expected to continue.

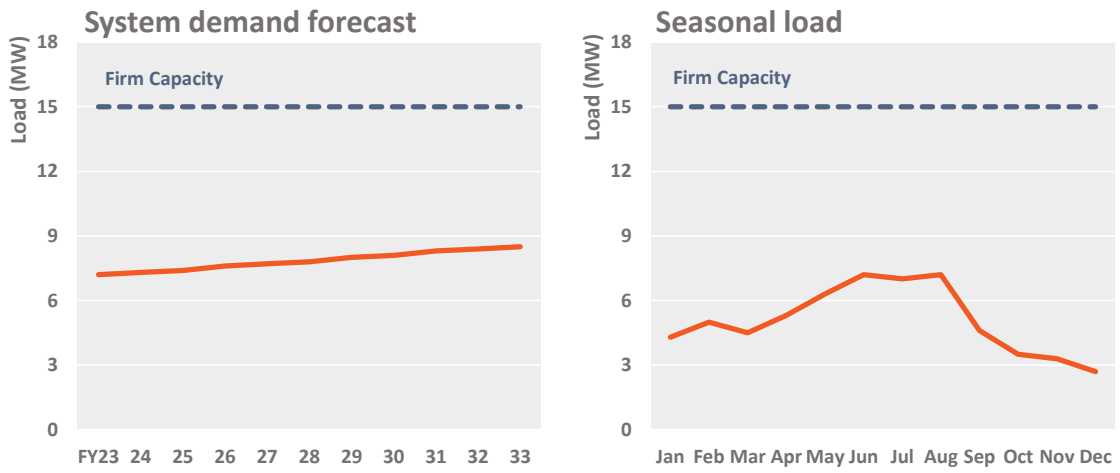
The 11kV switchboard at Onerahi substation was upgraded in 2010 and two 11kV feeders were reconfigured in 2015 to offload the Montgomery Road feeder. The two 7.5MVA 33/11kV transformers were replaced with two 15MVA transformers in 2019 to provide additional long-term capacity. The removed transformers have been refurbished and used in other parts of the network.

Onerahi zone substation technical summary

ONERAHI ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 15MVA	
Peak load			7MW	
Total number of customers supplied			4,030	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Beach Road	2	644	Overhead	Residential
Alamein Ave	3	1,010	Overhead	Residential
Cartwright Rd	6	796	Overhead	Residential
Tamaterau	7	557	Overhead	Residential
Montgomery Ave	8	1,023	Overhead	Residential

Substation demand

Onerahi zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Onerahi at this time.

Onerahi zone substation feeder map

Parua Bay zone substation

Substation overview

This substation supplies the Parua Bay, McLeod's Bay, Whangārei Heads, and Pataua areas, comprising mainly residential load. Load growth has been fairly low during the past five years; however, there is potential for significant development. This substation was commissioned early in 2007 utilising one of the refurbished 3.75MVA transformers relocated from the Hikurangi zone substation. This transformer is was replaced with a 5MVA unit in 2022 due to end of life. The new transformer will have enough capacity to meet forecasted incremental growth. A strategic spare transformer held in the second transformer bay will remain until it is no longer needed. An 11kV back feeding upgrade is planned for FY23–FY24. This project will increase the restorability of the single transformer zone substation significantly in preparation for the transformer upgrade.

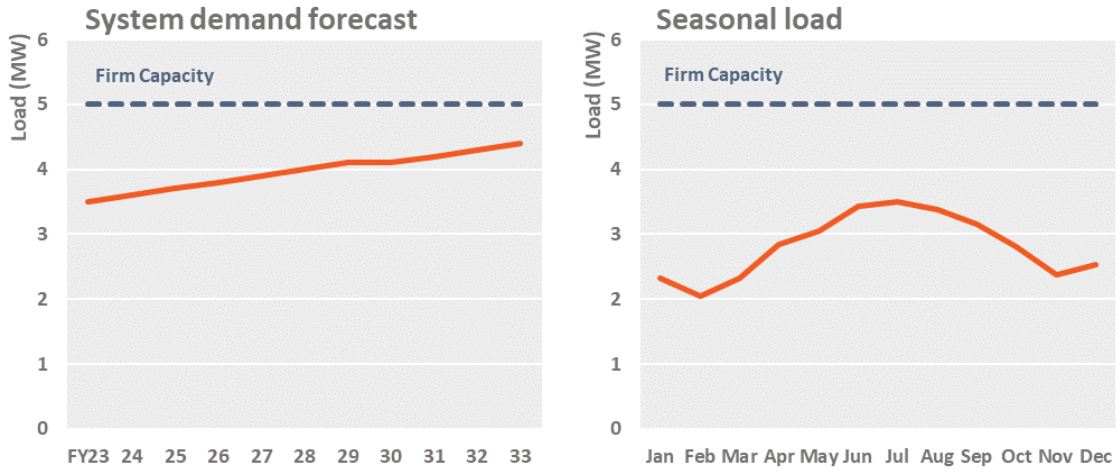
Parua Bay zone substation technical summary

PARUA BAY ZONE SUBSTATION PROFILE	
Transformer capacity	1 unit 5MVA
Peak load	3MW

Total number of customers supplied			2,278	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Pataua	1	928	Overhead	Residential
Parua Bay	2	572	Overhead	Residential
Whangārei Heads	3	778	Overhead	Residential

Substation demand

Parua Bay zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Parua Bay at this time.

Parua Bay zone substation feeder map

Tikipunga zone substation

Substation overview

This is Northpower's largest zone substation based on number of premises connected. Feeders supply the residential areas to the north of the CBD as well as the rural area to the north-east of Whangārei, which includes a large sawmill load. The substation load peaks in winter due to heating load. Load growth is moderate, driven primarily by residential growth

in the Kensington and Tikipunga suburbs, due to urban infill. Development is expected to continue in the area to the north and east of the substation.

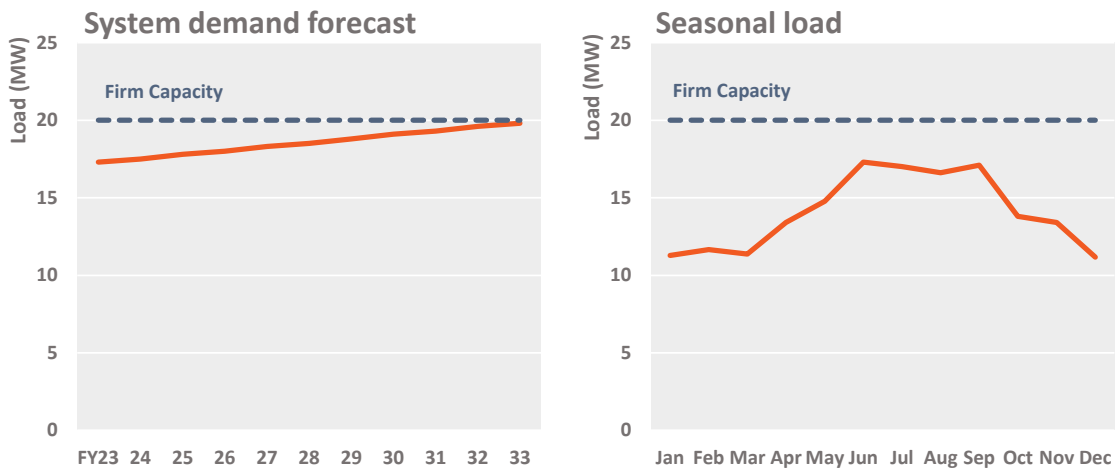
The 11kV oil switchgear at this station was replaced with modern gas insulated switchgear in 2008 and the transformers were upgraded to two 20MVA units in 2009. Some changes were recently made to feeder configurations, resulting in the transfer of some load from Kamo substation to Tikipunga substation.

Tikipunga zone substation technical summary

TIKIPUNGA ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 20MVA	
Peak load			17MW	
Total number of customers supplied			7,362	
FEEDER	CB	ICPS	LINE	CUSTOMER TYPE
Whau Valley	1	1,272	Overhead	Residential
Mains Ave	2	856	Overhead	Residential
Tikipunga Hill	4	1,005	Overhead	Residential
Cairnfield Rd	5	1,184	Overhead	Residential
Paranui	6	647	Overhead	Residential
Otangarei	7	948	Overhead	Residential
Kiripaka Rd	8	1,450	Overhead	Residential

Substation demand

Tikipunga zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Tikipunga at this time.

Tikipunga zone substation feeder map

Maungatapere zone substation

Substation overview

The substation supplies a predominantly rural area (dairy and fruit farming) around Maungatapere village, which includes Maungakaramea, Poroti, Tangiteroria, Puwera, and Mangapai.

Some load was transferred to Kioreroa substation in 2010 in order to maintain N-1 security. It is also possible to back feed some of the Maungatapere load via the 11kV network from Poroti substation if needed.

Some changes were recently made to feeder configurations in order to provide additional capacity in the Maunu area as an interim measure before the new Maunu substation is completed. Maungatapere substation transformers have been replaced by the two 7.5MVA 33/11kV transformers removed from Onerahi, providing the substation with the capacity required for the foreseeable future.

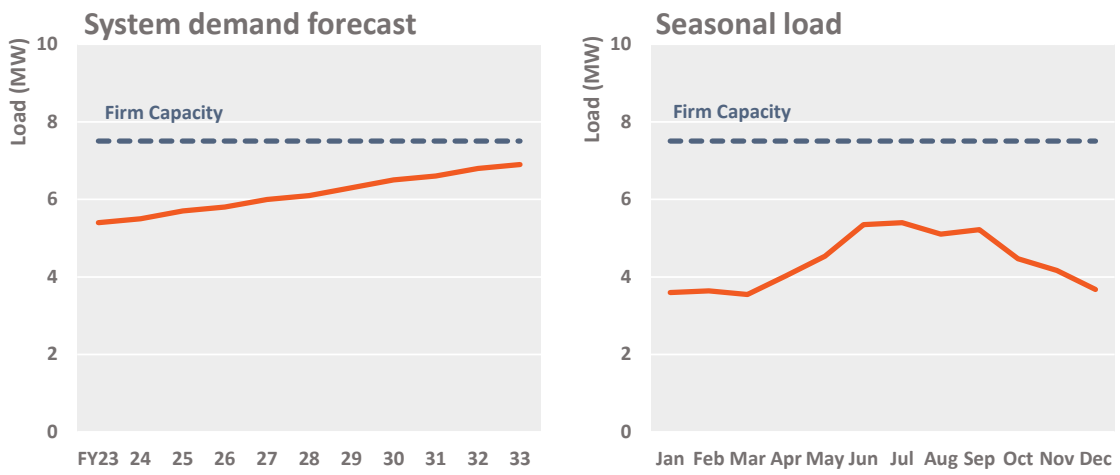
Maungatapere zone substation technical summary

MAUNGATAPERE ZONE SUBSTATION PROFILE	
Transformer capacity	2 units 7.5MVA
Peak load	5MW
Total number of customers supplied	2,815

FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Maunu Mountain	1	259	Overhead	Residential
Poroti	2	611	Overhead	Residential
Maungakaramea	3	599	Overhead	Residential
Maungatapere dairy factory	6	293	Overhead	Residential
Puwera	7	440	Overhead	Residential/Commercial mix
Whatitiri	8	613	Overhead	Residential

Substation demand

Maungatapere zone substation forecast system demand and seasonal load



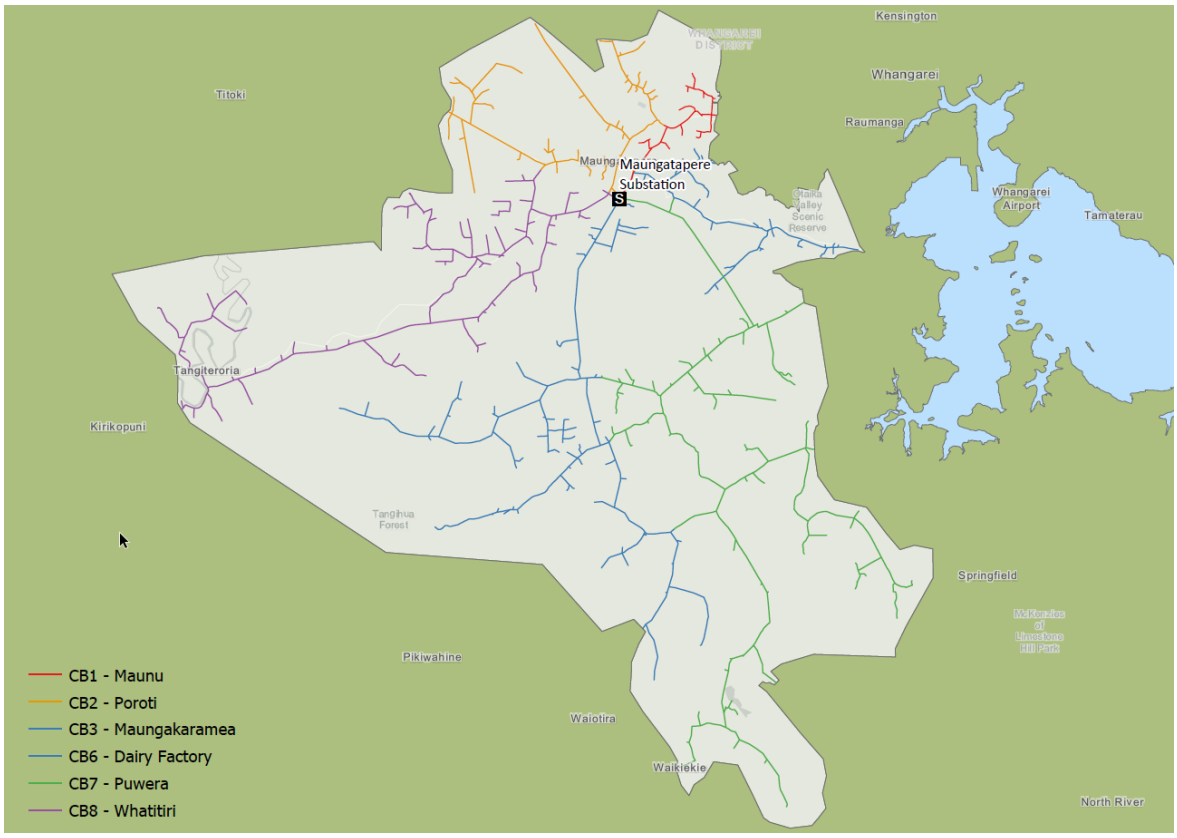
Forecast capital investment

Maungatapere zone substation key capex projects

GROWTH PROJECTS	TIMING
Restore the 33kV subtransmission from MPE to WHG The project will restore the connectivity of the existing 33 kV OH subtransmission line between Maungatapere regional substation and Whangārei South substation. The restoration of the disconnected subtransmission line, coupled with some network upgrades, will provide an additional 25MVA capacity to the subtransmission circuits. This will resolve the issue of supply security for the Kensington regional substation and meet the GPD of Whangārei, Maunu, and Kioreroa substations.	FY24-25

RENEWAL PROJECTS	TIMING
Maungatapere 110/33kV transformer replacements We are planning to replace two transformers that have poor winding insulation resistance readings and have poor external condition. These transformers have leaked in the past and are known to have design issues, resulting in corroded seals and drive shafts.	FY24-26
Maungatapere 33kV bus outdoor to indoor conversion The outdoor 33kV switchyard comprises strung bus and minimum oil circuit breakers. The strung bus and circuit breakers are arranged in a manner that doesn't meet modern safety clearances. The circuit breakers are also of an older type which is maintenance intensive and due for renewal. The insulators on the 33kV bus are pin-type insulators which have a known failure mode, causing insulation breakdown and flashover. The 33kV bus currently does not have a bus section breaker. A bus fault will result in the loss of supply to the entire region.	FY31-32

Maungatapere zone substation feeder map



Maunu zone substation

Substation overview

Maunu supplies a predominant residential area to the west of Whangārei city. There is a significant amount of lifestyle development in the rural areas and this trend is expected to continue in the future.

Maunu substation also offloaded parts of Whangārei South and Alexander Street substations. Maunu substation gives Whangārei hospital an extra level of security as it can be used as an additional supply if needed.

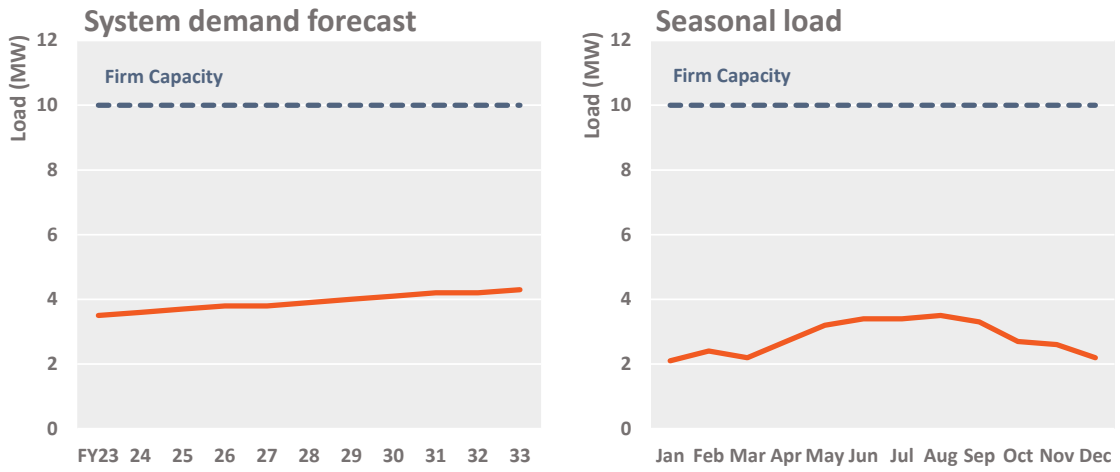
A large amount of upmarket subdivision activity is expected in the Maunu area as Whangārei city spreads westward. This is expected to result in substantial residential load growth in the medium to long term. We received an application for a retirement home in this area.

Maunu zone substation technical summary

MAUNU SUBSTATION PROFILE				
Transformer capacity			1 unit 10MVA	
Peak load			4MW	
Total number of customers supplied			1,634	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Te Hihi	1,022	349	Overhead	Residential
Maunu	1,032	828	Overhead	Residential
Austin Road	1,072	457	Overhead	Residential

Substation demand

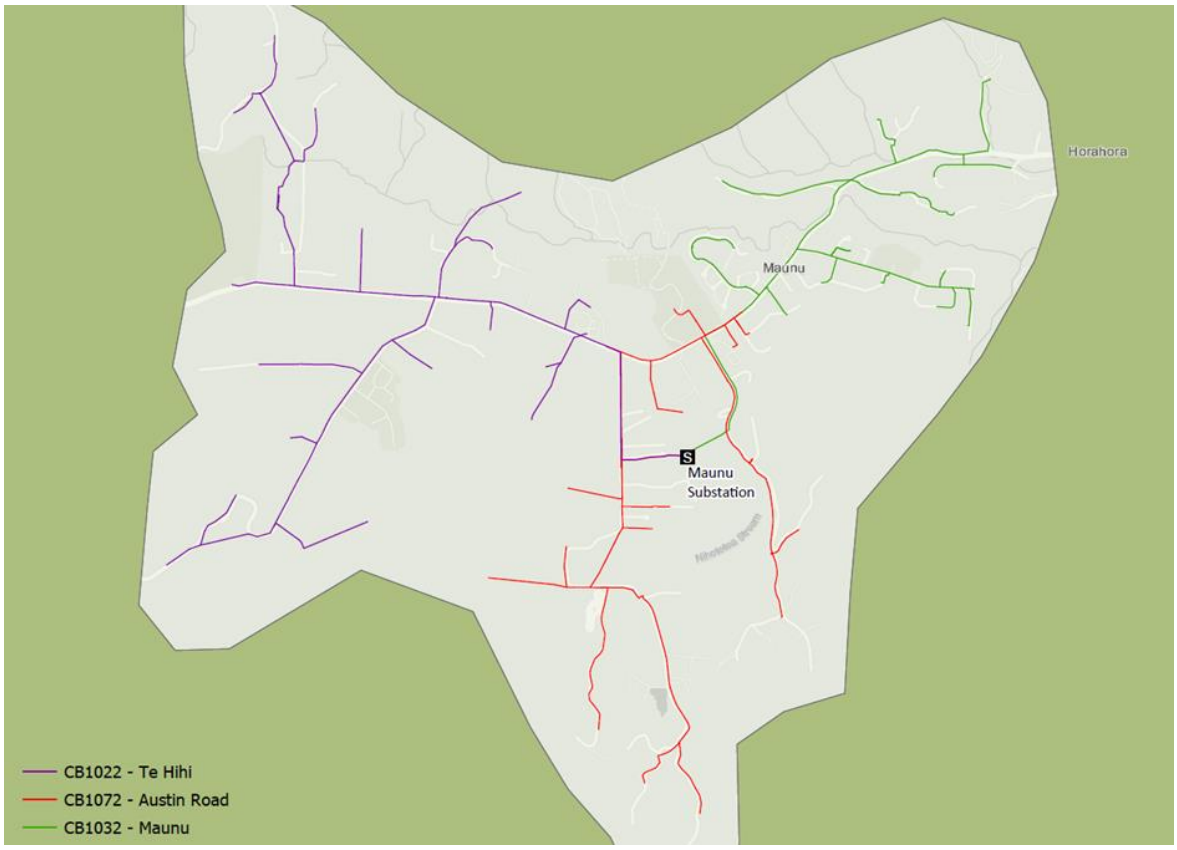
Maunu zone substation forecast system demand and seasonal load



Forecast capital investment

No capital investment is forecast at Maunu at this time.

Maunu zone substation feeder map



Kioreroa zone substation

Substation overview

The area supplied by this substation is dominated by heavy industry with associated light industry and commercial loads. The Portland area to the south of Whangārei is also supplied from this substation and includes some rural load. Load growth has been high in the past, due to the expansion of some industries, but has been marginal in recent years. With the development of Port Road we expect a significant amount of future growth as more land will become available for development. There was a large industrial load that has recently been decommissioned on CB1, allowing capacity for new connections in the area.

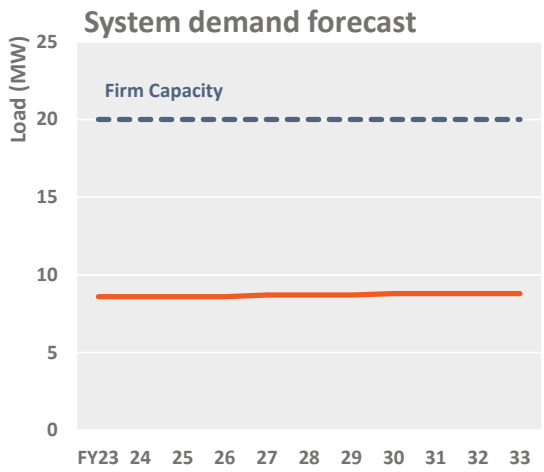
The two 10MVA transformers at this station were upgraded to two 15/20MVA in early 2006 in anticipation of the expected future load growth, as well as to support the upgrading of the transformers at three other zone substations. Some rural load south of Whangārei was transferred to this station from Maungatapere substation in 2010 in order to offload the transformers at the latter station. An additional 11kV feeder was commissioned in 2014 to offload Whangārei South substation and optimise feeder loadings.

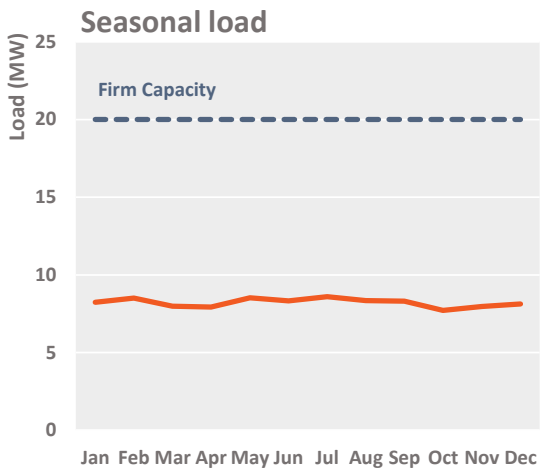
Kioreroa zone substation technical summary

KIOREROA ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 15MVA ONAN/20 MVA ONAF	
Peak load			9MW	
Total number of customers supplied			1,154	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Union East	1	141	Overhead	Residential/Commercial mix
Treatment	2	216	Overhead	Residential/Commercial mix
CHH Supermill	3	1	Underground	Industrial
Fraser	5	78	Overhead	Industrial
Fert. Works	6	95	Overhead	Industrial
ToeToe Rd	7	623	Overhead	Residential

Substation demand

Kioreroa zone substation forecast system demand and seasonal load

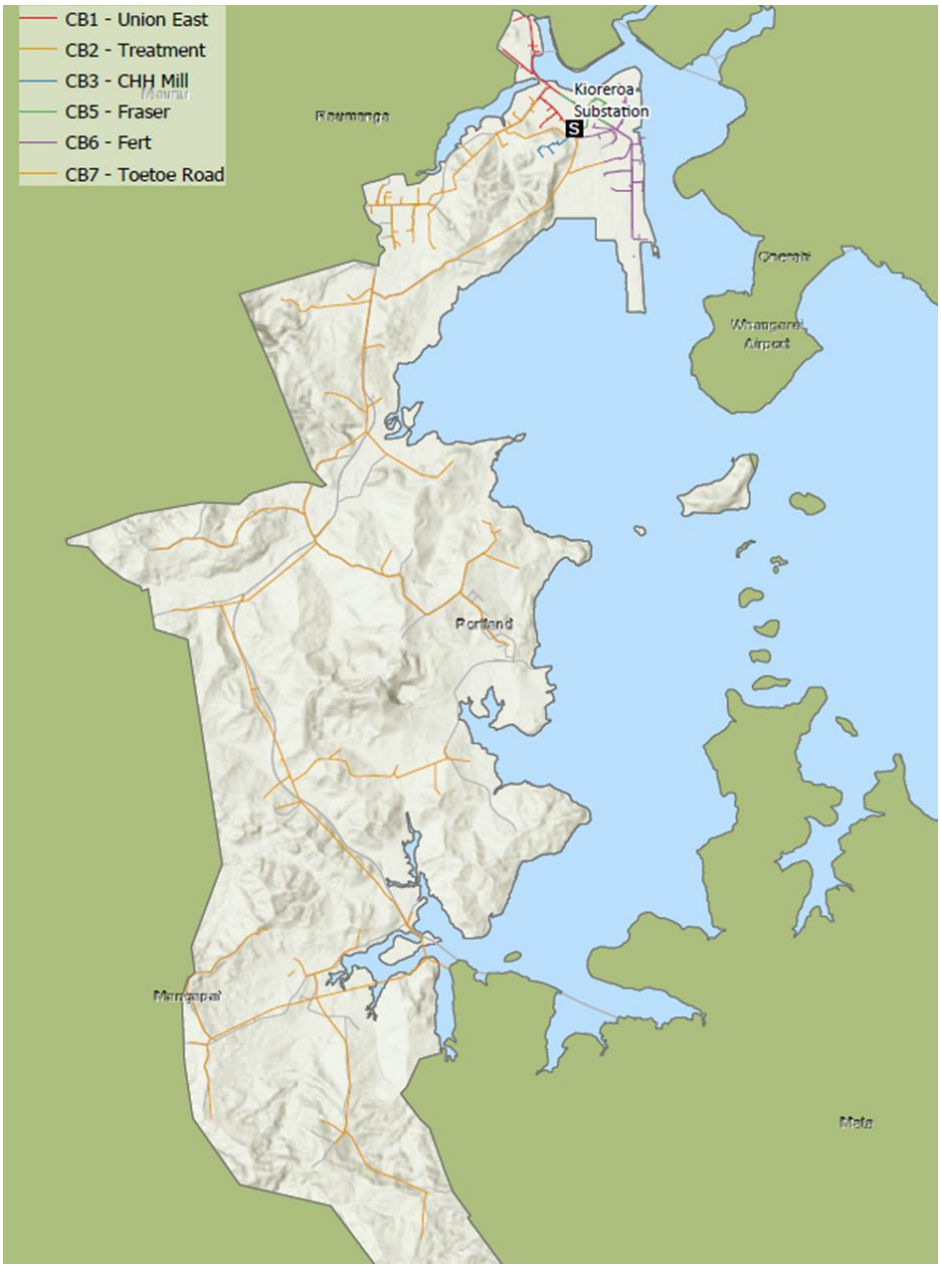




Forecast capital investment

No capital investment is forecast at Kioreroa at this time.

Kioreroa zone substation feeder map



Poroti zone substation

Substation overview

This substation supplies a predominantly rural region with no significant urban centres other than Titoki village. The substation covers a large area with a relatively small total load. Load growth is low with no signs of development, and future growth is also expected to be low. Poroti substation was built in 1990 to provide capacity for a large irrigation scheme proposed for the area. The scheme never developed as planned, but some dairy farms in the Titoki area later installed irrigation schemes.

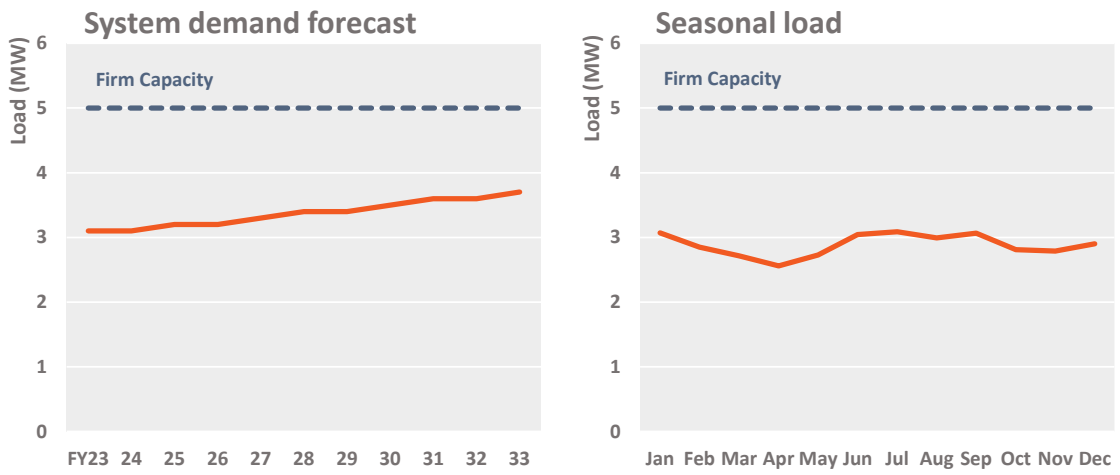
The load is seasonal and weather dependent. Residential and lifestyle growth is relatively low and any significant growth is more likely to come from additional irrigation schemes. The 5MVA transformer capacity at the substation is considered adequate for the medium term. The transformer and 11kV switchboard are planned to be replaced between FY23 and FY24 due to their age.

Poroti zone substation technical summary

POROTI ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 5MVA	
Peak load			3MW	
Total number of customers supplied			1,350	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Titoki	1	762	Overhead	Residential/Commercial mix
Hotel	4	116	Overhead	Commercial
Wharekohe	5	72	Overhead	Residential/Commercial mix
Kokopu	6	400	Overhead	Residential

Substation demand

Kioreroa zone substation forecast system demand and seasonal load



Forecast capital investment

Poroti zone substation key capex projects

RENEWAL PROJECTS	TIMING
Poroti transformer replacement The sole transformer at Poroti has poor winding insulation resistance test results and is of a type where spare parts are becoming scarcer to source. Failure of this transformer would result in a complete loss of supply to the Poroti community for a long period of time.	FY23-24

RENEWAL PROJECTS	TIMING
Poroti 11kV switchboard replacement The switchboard is made up of ~50-year-old oil type switchgear. Oil type switchgear is considered unsafe and has been phased out since the 1980s. This type of switchgear is more maintenance intensive compared to modern types. The 11 kV bus is also not segregated by a circuit breaker, meaning a bus fault will result in a complete loss of supply to the Poroti area.	FY23-24

Poroti zone substation feeder map

Whangārei South zone substation

Substation overview

This substation is situated to the south of Whangārei CBD and supplies a mixture of residential, commercial, and light industrial load. Two major customers are supplied from Whangārei South: Whangārei Hospital and Northland Polytechnic. The transformers at this station were upgraded to two 10MVA in 2006. The removed transformers have been refurbished and used in other parts of the network.

The peak load exceeds the transformer N-1 capacity; however, due to the close proximity of Alexander Street and Kioreroa substations, it is possible to transfer load if needed. We plan to replace these transformers in FY26–FY28 due to condition.

The new Maunu zone substation that was completed in FY22 allowed a transfer of some residential load lying to the west of Whangārei South. This has freed up some capacity to accommodate anticipated new load to the south, as well as some marginal growth of existing load.

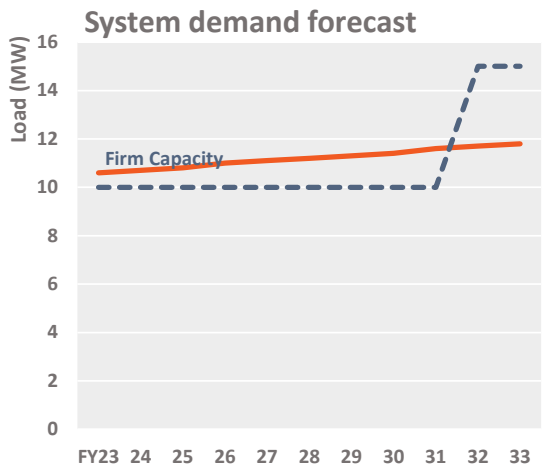
The commissioning of a new feeder at Kioreroa substation in 2014 allowed a portion of load from Whangārei South substation to be transferred to Kioreroa substation.

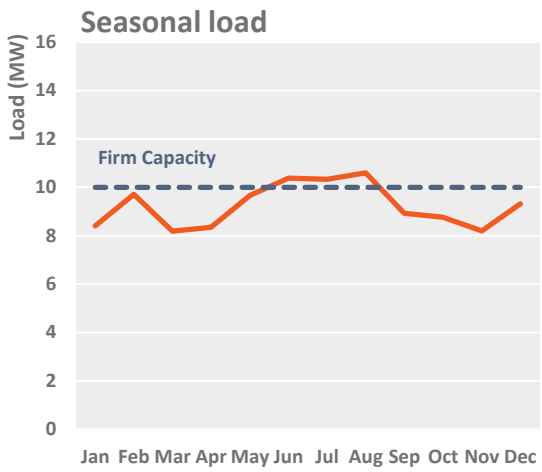
Whangārei South zone substation technical summary

WHANGĀREI SOUTH ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 10MVA	
Peak load			11MW	
Total number of customers supplied			3,300	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Otaika	1,042	47	Overhead	Residential
Kaka St	1,032	364	Overhead	Residential/Commercial mix
Te Mai	1,102	936	Overhead	Residential
Rewa Rewa Rd	1,082	909	Overhead	Residential
Okara Drive	1,092	478	Overhead	Residential
Walton St	1,022	566	Overhead	Residential

Substation demand

Whangārei South zone substation forecast system demand and seasonal load



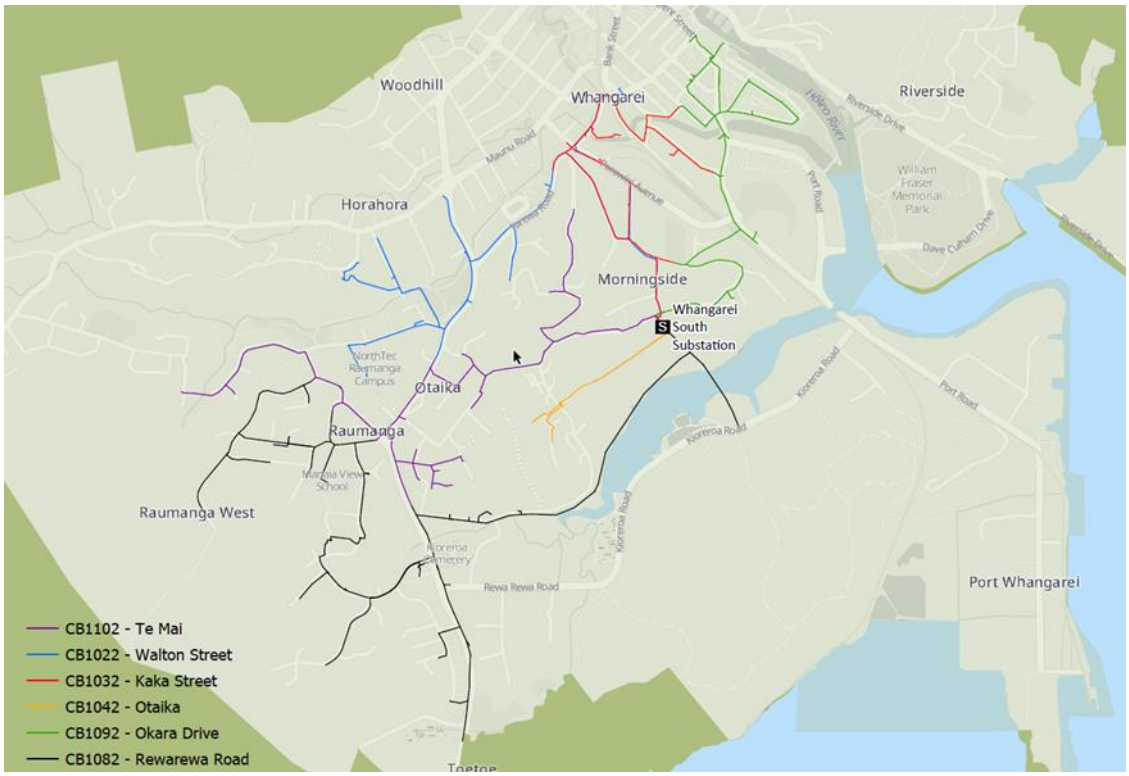


Forecast capital investment

Whangārei South zone substation key capex projects

RENEWAL PROJECTS	TIMING
WHG to ALX 33kV oil cable replacement The WHG to ALX cable circuit comprises a 56-year-old, 2.2km oil cable. This cable has leaked extensively in the past and oil pressure has consistently dropped, which increases its risk of insulation failure. The cable is predominantly used for back-feed purposes. We anticipate the back feed will be required more frequently in the future due to increasing extreme weather events. Replacing this cable will make the 33kV subtransmission network around the Whangārei area more resilient against these events.	FY26-27
Whangārei South transformer replacements There are two transformers feeding the Whangārei South zone substation. One of the transformers has poor winding condition and recent impedance testing indicate that there is deformation. The other transformer also has low insulation resistance test results and there is a risk of catastrophic failure for both transformers. Replacing these transformers will address this risk.	FY26-28
Whangārei South 33kV outdoor to indoor conversion The 33kV outdoor switchyard at Whangārei South has space constraints and does not meet modern safety clearance requirements. It also comprises old switchgear which will be due for renewal by the end of the period. Converting the outdoor switchyard to indoors will increase overall reliability as indoor switchgear are less prone to unplanned outages.	FY32-33

Whangārei South zone substation feeder map



Maungaturoto zone substation

Substation overview

The load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand. The dairy factory load is expected to increase in the short to medium term. The remainder of the load comprises Maungaturoto township and large surrounding rural area, in which the load is predominantly dairy farming. Maungaturoto substation is an important backstop for Kaiwaka and Mareretu single transformer substations.

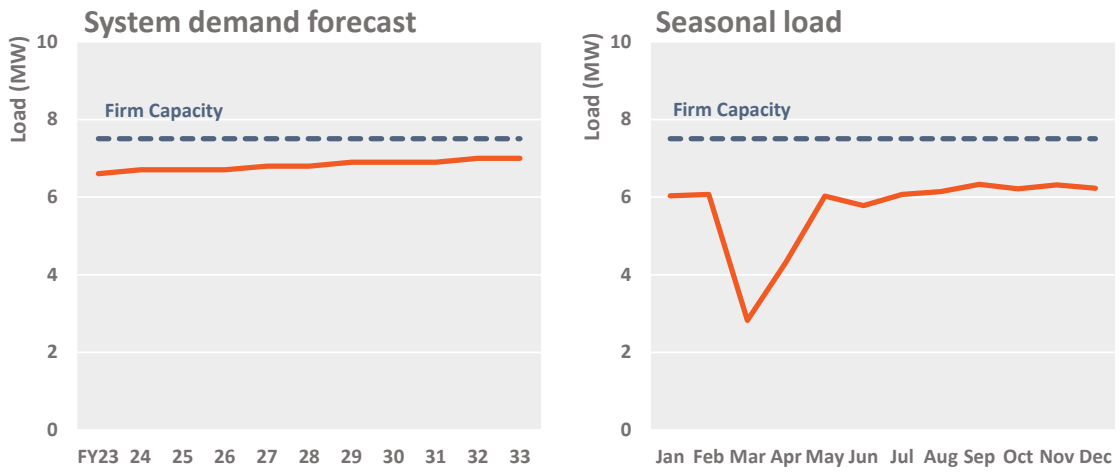
Growth in the township and surrounding area is low. Future load growth potential is mainly driven by the possible expansion of the dairy factory in the longer term. The two 5MVA transformers at this station were replaced with 7.5MVA units in 2006. The 10-year plan makes provision for upgrading the 11kV switchboard and replacing the transformers in FY24 to FY26 for age reasons.

Maungaturoto zone substation technical summary

MAUNGATUROTO ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 7.5MVA	
Peak load			7MW	
Total number of customers supplied			945	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Brynderwyn	1	188	Underground	Residential/Commercial mix
Bickerstaff	2	752	Overhead	Residential
Maungaturoto dairy factory	4	5	Overhead	Industrial

Substation demand

Maungaturoto zone substation forecast system demand and seasonal load



Forecast capital investment

Maungaturoto zone substation key capex projects

GROWTH PROJECTS	TIMING
Maungaturoto to Mangawhai new 33kV Line The project will install a new 28km subtransmission cable/line from Maungaturoto substation to Mangawhai substation to improve the reliability and security of supply to Kaiwaka and Mangawhai zone substations. This will also support the growing demand in the Mangawhai area and provide contingency supply under planned outages to perform asset renewal and maintenance. The design is complete and project is underway.	FY23-25
RENEWAL PROJECTS	**TIMING**
Maungaturoto transformer replacements This project will replace two transformers that have poor internal winding condition. Recent tests have failed insulation resistance between HV and LV windings, despite a mid-life overhaul being undertaken.	FY24-26
Maungaturoto 11kV switchboard replacement The 11kV switchboard at Maungaturoto is ~50 years old and is made up of five oil filled switchgear. This switchboard has relatively high arc flash incident energy which elevates worker safety risks. The switchboard is also obsolete as spare parts are becoming scarcer to source. We will replace this switchboard at the same time as the transformer so we can deliver this project more efficiently.	FY24-26

Maungaturoto zone substation feeder map

Kaiwaka zone substation

Substation overview

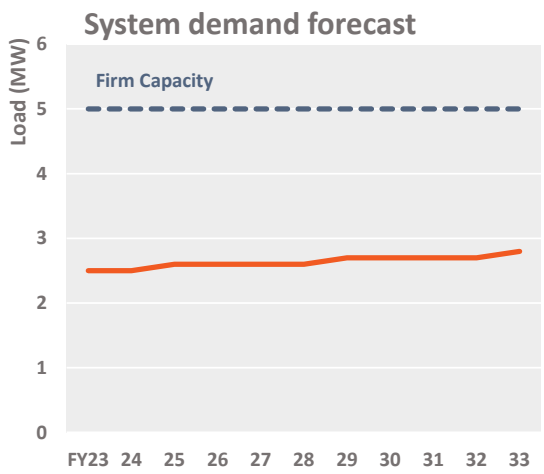
This substation supplies Kaiwaka township and the surrounding rural area, which is predominantly dairy farming. There is, however, an increasing amount of lifestyle block development. The demand for lifestyle properties is expected to continue or even increase due to the proximity to Auckland and the development in the Oneriri and Topuni (Kaipara Harbour) areas. The 11kV switchboard is planned to be replaced in FY23 to FY24.

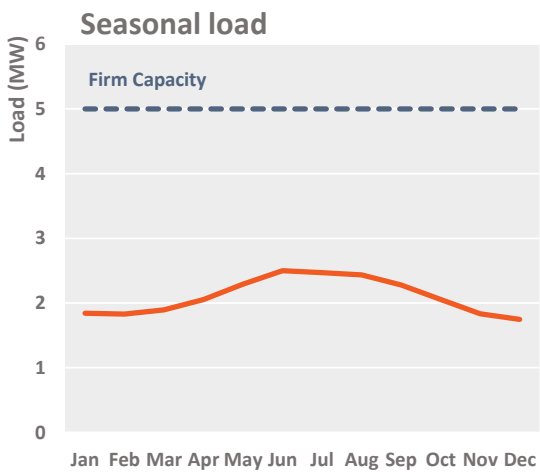
Kaiwaka zone substation technical summary

KAIWAKA ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 5MVA	
Peak load			3MW	
Total number of customers supplied			1,951	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
North Kaiwaka	1	214	Overhead	Residential
Kaiwaka town	4	473	Overhead	Residential
Hakaru	5	764	Overhead	Residential
Topuni	6	500	Overhead	Residential

Substation demand

Kaiwaka zone substation forecast system demand and seasonal load





Forecast capital investment

Kaiwaka zone substation key capex projects

RENEWAL PROJECTS	TIMING
Kaiwaka 11kV switchboard replacement The project will replace a 54-year-old 11kV oil filled switchboard. This switchboard is now obsolete, with no spare parts to service it. Replacement will address its failure and obsolescence risk.	FY23-24

Kaiwaka zone substation feeder map

Mangawhai zone substation

Substation overview

The load on this substation is made up primarily of coastal residential, with holiday homes and rural lifestyle dominating. Some commercial connections are present and there is also some dairy farming in the Tara area. The urban areas include Mangawhai Heads, Mangawhai Village, Langs Cove, and Waipu Cove. The substation load is characterised by high peak demands during holiday periods. The load has grown at a higher rate in recent years compared to other parts of Northpower's network distribution. Further growth is expected in the future due to Mangawhai's proximity to Auckland.

A second 5MVA transformer was commissioned at this station at the end of 2009 for both capacity and security of supply reasons. The Moir Point feeder was extended by a cable link to offload the Mangawhai Heads feeder as well as providing feeder backstopping capability. A significant amount of investment is forecasted between FY23 and FY25, consisting of 11kV backfeed upgrades, a new 33/11kV zone substation, and a new 33kV line from Maungaturoto to Mangawhai. These upgrades are driven by the rapid growth in the area.

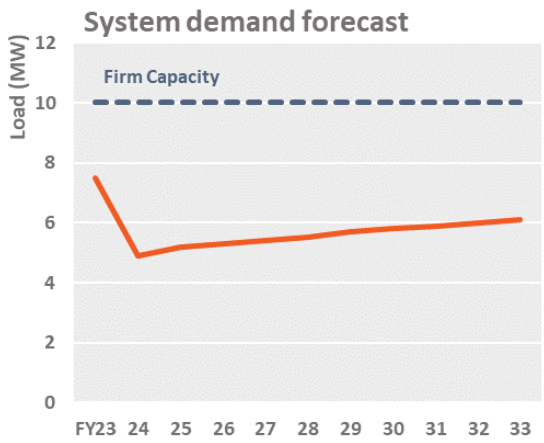
A new township is currently under development which will connect into Moir Point feeder, driving the need for further capacity upgrades.

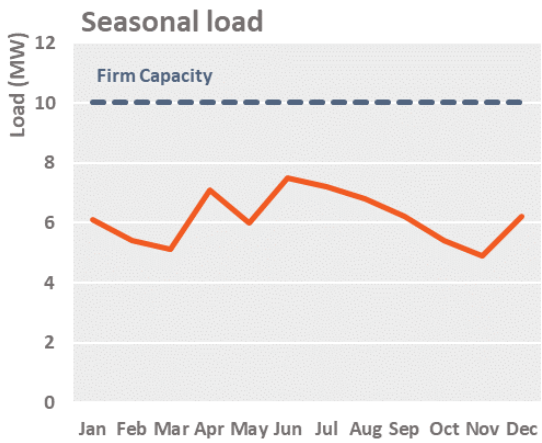
Mangawhai zone substation technical summary

MANGAWHAI ZONE SUBSTATION PROFILE				
Transformer capacity			2 units 5MVA	
Peak load			8MW	
Total number of customers supplied			4,448	
FEEDER	CB	ICP	LINES	CUSTOMER TYPE
Mangawhai Heads	1	1,360	Overhead	Residential
Tara	2	840	Overhead	Residential
Langs Beach	3	747	Underground	Residential
Moir Point	4	1,501	Overhead	Residential

Substation demand

Mangawhai zone substation forecast system demand and seasonal load[42]





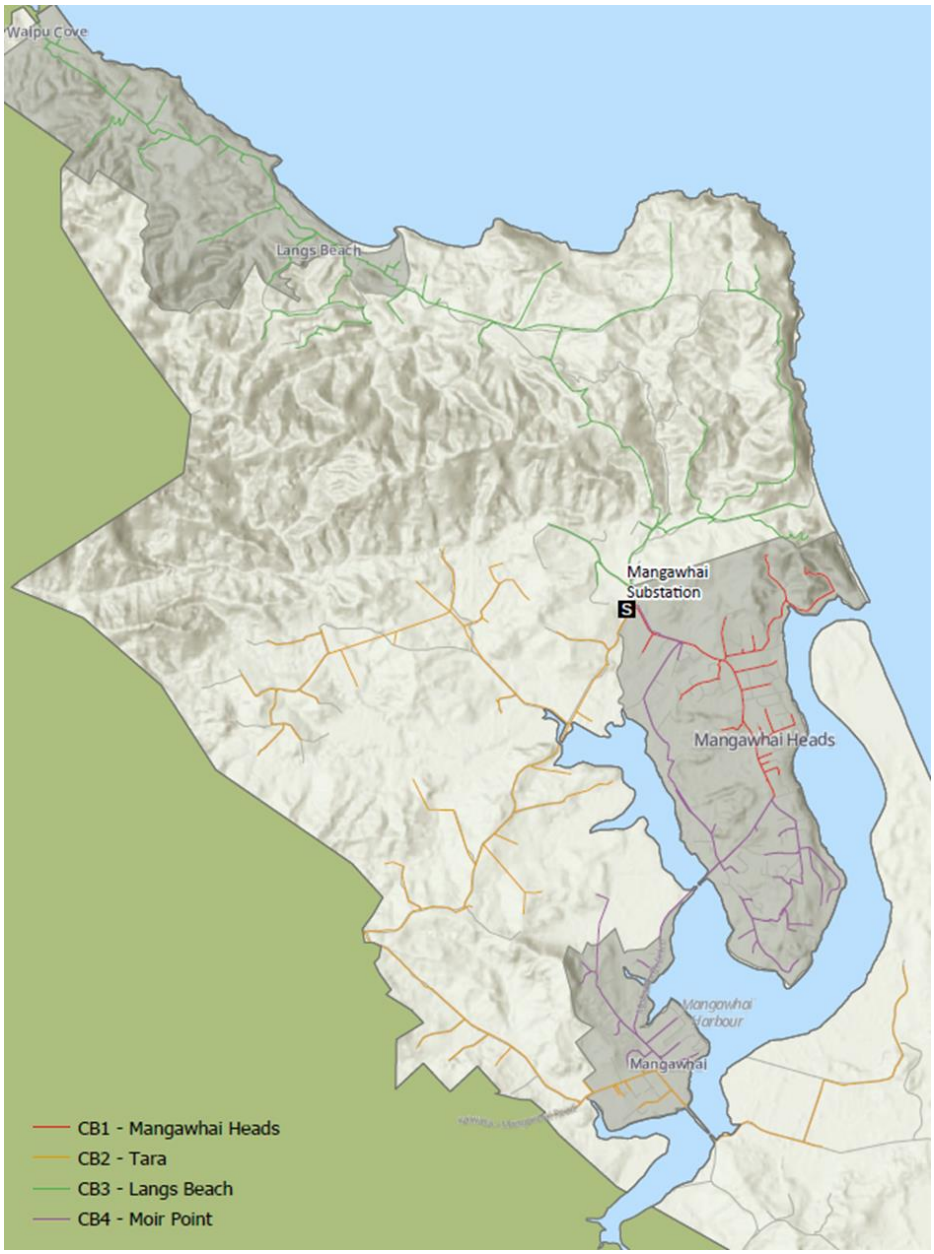
Forecast capital investment

Mangawhai zone substation key capex projects

GROWTH PROJECTS	TIMING
Mangawhai Central zone substation The project will install a new 15/23MVA substation to support the emerging load growth. Growth in the Mangawhai area has accelerated since 2020. An upgrade in network capacity is required to support further development and security of supply. The design is complete, and the project is underway.	FY23-25

42 The firm capacity is shown as 10MW at Mangawhai. This is because once the new Mangawhai Central zone substation is built this will provide N-1 to the existing Mangawhai substation. The current N-1 capacity is 5MW.

Mangawhai zone substation feeder map



Mareretu zone substation

Substation overview

The load on this substation is predominantly rural dairy farming with no significant urban centres other than Paparoa village. The substation supplies a large area, although the total load is relatively small. Load growth is low, with no sign of significant development in the short to medium term. There is, however, significant potential for lifestyle development in the Matakohe and Tinopai areas.

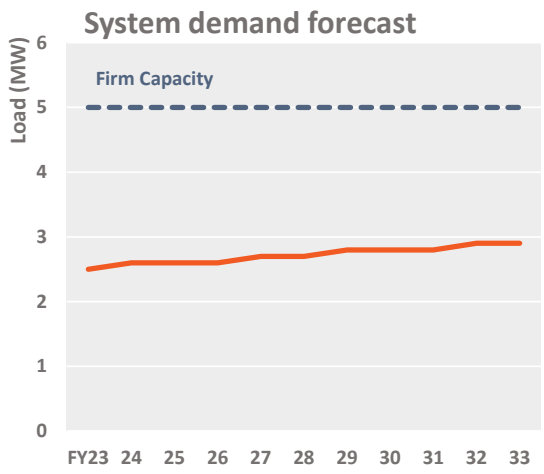
In FY33 the 11kV switchboard is forecasted for replacement due to condition.

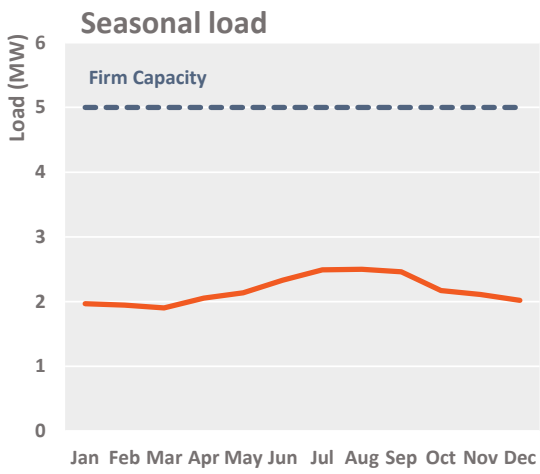
Mareretu zone substation technical summary

MARERETU ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 5MVA	
Peak load			3MW	
Total number of customers supplied			2,086	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Taipuha	1	454	Overhead	Residential/Commercial mix
Ararua	2	640	Overhead	Residential
Wairere	5	397	Overhead	Residential
Paparoa	6	595	Overhead	Residential

Substation demand

Mareretu zone substation forecast system demand and seasonal load





Forecast capital investment

Mareretu zone substation key capex projects

RENEWAL PROJECTS	TIMING
Mareretu 11kV switchboard replacement The Mareretu 11kV switchboard comprises five oil filled switchgear which are now ~40 years old. The switchboard is also obsolete and there are no spare parts available. We are replacing this switchboard in order to address its failure and obsolescence risk.	FY33-34

Mareretu zone substation feeder map

Ruawai zone substation

Substation overview

This substation supplies Ruawai town, with demand dominated by the surrounding rural dairy farming area. Growth is low and this trend is expected to continue for the short to medium term.

Some load was transferred from the Dargaville area in 2015, which resulted in a fairly significant increase in substation peak load. The 11kV switchboard is planned to be replaced in FY23–FY24 for condition reasons. At the same time, the 5MVA transformer will also be replaced.

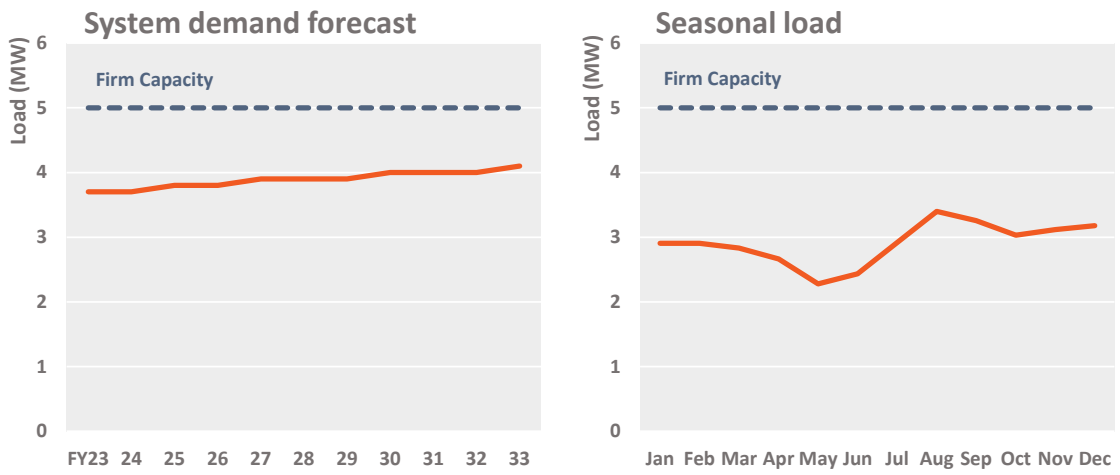
Ruawai has relatively low restorability due to the remote, coastal location.

Ruawai zone substation technical summary

RUAWAI ZONE SUBSTATION PROFILE				
Transformer capacity			1 unit 5MVA	
Peak load			3MW	
Total number of customers supplied			1,676	
FEEDER	CB	ICPS	LINES	CUSTOMER TYPE
Dunns Rd	1	368	Overhead	Residential/Commercial mix
Ruawai town	4	327	Overhead	Residential
Tangaihe	5	644	Overhead	Residential/Commercial mix
Access Rd	6	337	Overhead	Residential/Commercial mix

Substation demand

Ruawai zone substation forecast system demand and seasonal load

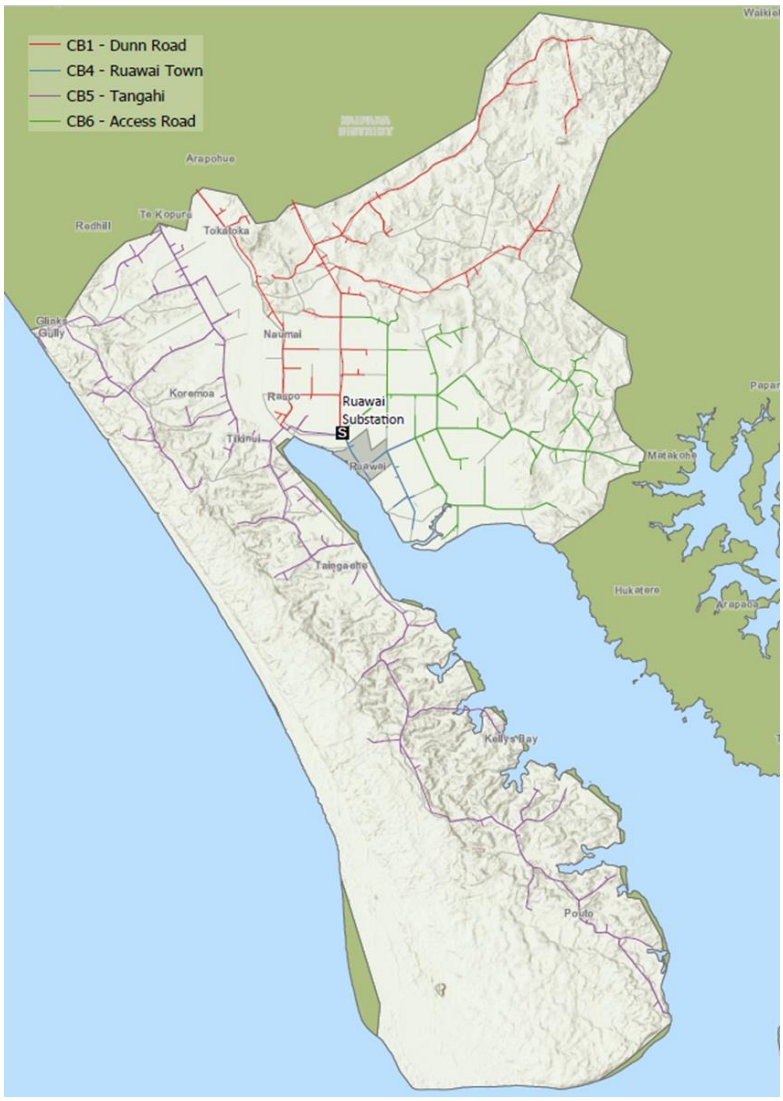


Forecast capital investment

Ruawai zone substation key capex projects

RENEWAL PROJECTS	TIMING
Ruawai transformer replacement The sole transformer feeding Ruawai is currently leaking, despite a number of repairs. A recent furans test resulted in a DP reading of ~400, indicating the transformer is nearing the end of its life. The insulation resistance test has shown moderate deterioration in the winding insulation. Overall, the transformer is in poor condition and we are replacing it in the next two years to address this failure risk.	FY23-24
Ruawai 11kV switchboard replacement This project will replace a ~50 year old switchboard which contains five oil filled switchgear. The switchboard has exceeded its expected life and spare parts are becoming scarcer. We are replacing this switchboard to address its failure and obsolescence risk. We are also replacing the transformer to optimise delivery.	FY23-24

Ruawai zone substation feeder map



Significant projects investment analysis

The following section covers more detail on the significant network development projects and the options analysis undertaken to identify the preferred option.

Mangawhai Central zone substation

Preferred option identified:

New single transformer zone substation in Mangawhai township.

Alternative options considered:

We reviewed 13 different options to address the security of supply and reliability need. Four of these options were subsequently shortlisted for detailed costing and economic analysis, as summarised in the following table.

The status quo option was not shortlisted, as refusing to connect new customers is not a feasible solution. We did not shortlist the option of upgrading the existing substation as it only meets the short-term need and would be unable to pick up the load growth in southern Mangawhai without significant feeder upgrades.

A non-network solution was considered, using a mixture of battery storage and diesel generation as peak lopping to reduce the load of the existing substation. This would not improve reliability or security of supply to Mangawhai so was not shortlisted.

Overview of the economic analysis of the short-listed options

	NPV COSTS($)			
OPTIONS	CAPEX	RELIABILITY	OPEX	TOTAL
New 2 transformer substation north of causeway	$9.1m	$3k	-	$9.1m
New 2 transformer substation in Mangawhai Township	$8.4m	$3k	-	$8.4m
New single transformer substation north of causeway	$7.6m	$8k	-	$7.6m
Recommended New single transformer substation in Mangawhai township	$7.2m	$8k	-	$7.2m

Maungaturoto to Mangawhai 34km 33kV subtransmission line

Preferred option identified:

Construct a new 33kV cable from MTO - Mt. Rd - SH1 - KAI – MWI Central

Alternative options considered:

We reviewed 14 different options to address the constraint, with four options shortlisted for costing and economic analysis, as summarised in the following. The status quo option (i.e. do nothing) was not shortlisted, because investment is required in the near term to meet the N security constraint. Therefore, in this analysis, we are looking for the lowest-cost option to address the network constraint.

The analysis shows that the lowest-cost option is to construct a new 33kV cable/line between MTO and MWI. The expected upfront cost of the overhead line is lower; however, due to the lower ongoing reliability risk associated with a cable and higher maintenance costs associated with an overhead line, the whole-of-life costs of a cable are lower.

Due to the uncertainty in the estimates (in particular consenting costs), the solution will likely be a mix of overhead line and underground cable where it works practically, and where easement costs can be minimised.

A non-network solution was considered using a mixture of battery storage and diesel generation as peak lopping to reduce the load of the existing substation. This would not improve reliability or security of supply to Mangawhai so was not shortlisted.

Overview of the economic analysis of the short-listed options

	NPV COSTS($)			
OPTIONS	CAPEX	RELIABILITY	OPEX	TOTAL
Construct a new 33kV line from MTO to MWI via KAI largely following the route of the existing 33kV line and pass through future growth areas (30km)	$13.4m	$4.3m	$1.9m	$19.6m
Construct a new 33kV line from MTO - Mt. Rd - SH1 - KAI – MWI South – MWI	$14.3m	$1.3m	$0	$15.6m
Construct a new 33kV cable from MTO - SH12 - SH1 - Bld. Rd - MWISouth - MWI by pass KAI	$14.3m	$2.7m	$1.9m	$18.9m
Recommended Construct a new 33kV cable from MTO - Mt. Rd - SH1 - KAI – MWI Central	$17.2m	$1.3m	$0	$18.5m

Kensington 110 kV bus reconfiguration

Preferred option identified:

Install a 110kV bus arrangement with bus section circuit breaker.

Alternative options considered:

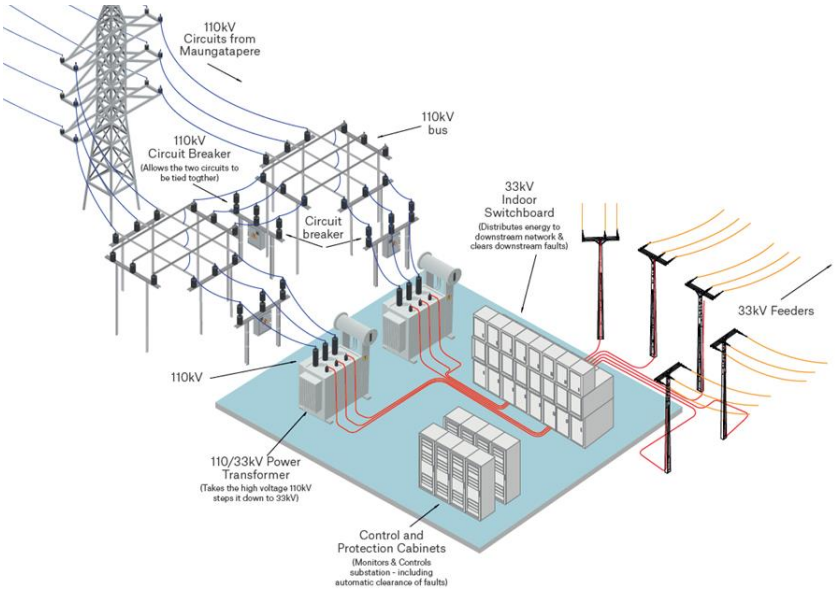
The current 110kV arrangement at Kensington means that each of the two incoming lines feed one transformer each. Without a bus on the 110kV, both lines cannot feed one transformer (or one line cannot feed both transformers). If a transformer is out of service for an extended period and the opposite line has a significant fault, supply to all of the downstream customers would be lost until the line and transformer can be restored. This would have a significant impact on our network. This event is a high impact low probability (HILP) risk and the consequence of this event occurring is not acceptable. We have chosen to mitigate this risk by creating a 110kV bus. Therefore, the do nothing option was not considered.

The options identified to address this risk were:

- install a bus arrangement with a bus section disconnector
- install a bus arrangement with a bus circuit breaker.

The bus circuit breaker was chosen as the preferred option as it only has marginally higher costs than the disconnector and would allow switching to occur remotely and without an outage, minimising downtime on the network. This would also give flexibility to keep the other assets in service during an outage of either line or either transformer and effectively remove the possibility of this high-consequence event. Having circuit breakers on the 110kV bus would have the added benefit that the protection system would not rely on a communications link back to Transpower Maungatapere substation circuit breakers.

Kensington substation with 110kV bus arrangement installed (simplified for illustrative purposes)



APPENDIX D. FURTHER RISK INFROMATION

High Impact Low Probability (HILP) events are rare, but when they do occur, they have a more significant impact than that is usually catered for in our security of supply criteria. They include extended outages and major common mode failure events. The following sections discuss externally driven and asset specific HILP risks.

Externally Driven HILP Risks

We have identified the following list of low-probability, externally driven events that could have unacceptable consequences on our operations.

Table D.1: Externally Driven HILP Risks

EVENT DESCRIPTION	HILP SCENARIO	IMMEDIATELY AVAILABLE ACTIONS (OPERATIONAL)	INVESTMENT OPTIONS FOR RISK REDUCTION	ACTIONS: FY24 – 26
Major natural disaster, such as earthquake, tsunami, cyclone	Multiple parts of the network damaged and widespread outages Increasing impacts of climate change e.g. severe flooding	Repair and restoration through emergency response Backfeed where possible through parts of network where supply was maintained Civil Defence and Emergency Management (CDEM) responses	Systems to support restoration activities. Network 'hardening' Changes to standards and security of supply criteria	Continue our active role in CDEM to ensure appropriate planning has taken place Complete deployment of ADMS and outage management system Development of formal climate change and resilience strategies
Catastrophic incident at transmission level	Loss of majority or all of network supply	Engagement with Transpower and provide support in restoration activities	Engage with Transpower to provide resilience of supply to the upper North Island	Engage with Transpower to understand vulnerabilities and look at investment options

EVENT DESCRIPTION	HILP SCENARIO	IMMEDIATELY AVAILABLE ACTIONS (OPERATIONAL)	INVESTMENT OPTIONS FOR RISK REDUCTION	ACTIONS: FY24 – 26
Pandemic	Widespread lockdowns, minimal ability to work	Staff who can work from home, work from home Implement working "bubbles" to minimise transmission between staff Follow public health advice	Investment in systems to enable and improve remote working ability.	Continue to move paper-based processes online to be able to be carried out remotely. Continue to improve remote-working tools and management.
Major Cyber Security Attack	Loss of control of network, widespread loss of supply	Disconnect comprised systems from the network. Manual operation of equipment. Engage external specialists to assess and control the situation.	Continued investments in cyber security capability. Continued investment in lifecycle renewals and removal of legacy systems.	Completion of a cybersecurity review and penetration test, progress remedial actions. The development of a formalised disaster recovery plan. The gradual introduction of continuous vulnerability detection and protection from distributed denial of services attacks.

Asset Specific HILP Risks

The following are asset-specific high consequence events that could occur. These events have very low probability of occurring however the consequence of these occurring is not acceptable. We are working to put in place appropriate plans to mitigate these risks over the coming years.

Table D.2: Asset Specific HILP Risks

ASSET DESCRIPTION	HILP SCENARIO	IMMEDIATE ACTIONS (OPERATIONAL)	INVESTMENT OPTIONS FOR RISK REDUCTION (CAPEX)	OTHER RESPONSE OPTIONS	ACTIONS: FY24 – 26
2 x 110kV lines Maungatapere to Kensington	Loss of one or multiple towers resulting in loss of double circuit.	Perform 33kV switching to transfer load to MPE. This has limited capability in high load times.	Build one new 110kV line from MPE to KEN. Build stronger interconnections in the 33kV network to backup from MPE.	Deploy emergency response system (Lindsay Towers) as a temporary measure to reinstate 110kV supply to Kensington. Assess and commence works to rebuild tower(s).	1) Assess for each tower site: access, stability, vulnerability, suitability for the deployment of emergency response system. 2) Define scope of works to improve any shortfalls in 1. 3) Improve asset management approach of towers.
Kensington 110/33kV transformers	Loss of both 110kV/33kV transformers at Kensington.	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Purchase a spare transformer. Enter into an agreement with other utilities to share a 110/33 kV spare.	Repair transformer.	1) Investigate purchase of a spare 110/33kV TX. 2) Assess risks associated with Kensington site and mitigate as far as practicable.
Kensington 33kV bus	Loss of entire 33kV bus	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Upgrade 33kV switchboard to have two separate 33kV buses. Upgrade 33kV interconnections to MPE.	Carry out sufficient repairs to get half the bus operational.	Upgrade 33kV switchboard is underway. We expect this risk will be removed by FY24.

ASSET DESCRIPTION	HILP SCENARIO	IMMEDIATE ACTIONS (OPERATIONAL)	INVESTMENT OPTIONS FOR RISK REDUCTION (CAPEX)	OTHER RESPONSE OPTIONS	ACTIONS: FY24 – 26
Maungatapere regional substation 110/33kV transformers	Loss of all 110/33kV transformers.	Perform 33kV switching to transfer load to MPE. Deploy generators to restore load.	Install third 110/33kV transformers in nearby location as a backup that are seismic rated.	Repair transformer.	Investigate purchase of a spare 110/33kV TX.
Maungatapere 33kV bus	Loss of entire 33kV bus.	Perform 33kV switching to transfer load to KEN. Deploy generators to restore load.	Install an modern indoor 33kV switchboard that has fast acting protection and 2 separate bus sections. Upgrade 33kV interconnections with KEN.	Ensure spares are available and repair any damage to the 33kV bus.	1) Investigation ODID option for MPE 33kV. 2) Investigate further reinforcement options between MPE and KEN.
2 x 50kV lines Maungatapere to Dargaville	Loss of one or multiple towers resulting in loss of both 50kV circuits.	Perform 33kV switching to transfer load to KEN. Deploy generators to restore load.	Build new 50kV line from MPE to DAR to establish an alternate 50kV ring. Reinforce 11kV to improve backfeed capability.	Deploy emergency response system (Lindsay Towers) as a temporary measure to reinstate 110kV supply to Kensington. Assess and commence works to rebuild tower(s).	1) Assess for each tower site: access, stability, vulnerability, suitability for the deployment of emergency response system. 2) Define scope of works to improve any shortfalls in 1. 3) Improve asset management approach of towers.

APPENDIX E. DISCLOSURE REQUIREMENTS

This compliance matrix provides a look-up reference for each AMP-related Information Disclosure requirement.

Table E.1: Disclosure requirements checklist

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6	**ASSET MANAGEMENT PLANS AND FORECAST INFORMATION**	
2.6.1	Except as provided in clause 2.6.1A, and subject to clause 2.6.3, before the start of each disclosure year commencing with the disclosure year 2014, Each EDB must complete an AMP that- (1) Complete an AMP that— (a) relates to the electricity distribution services supplied by the EDB; (b) meets the purposes of AMP disclosure set out in clause 2.6.2; (c) has been prepared in accordance with (i) in Aurora's case, clauses 1 to 18 of Attachment A; and (ii) in the case of each other EDB, clauses 1 to 17 of Attachment A; (d) contains the information set out in the schedules described in clause 2.6.6; (e) contains the Report on Asset Management Maturity as described in Schedule 13; (2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and (3) Each EDB must publicly disclose the AMP. (4) Each EDB may choose to publicly disclose the information in clauses 17.117.6 of Attachment A in any of the following forms: (a) wholly in the EDB's AMP, in line with clause 2.6.1 above; or (b) wholly in a document(s) separate to the AMP, provided that- (i) the document is made publicly available on the EDB's website; and (ii) the contents page of the EDB's most recent AMP includes a hyperlink reference to the website where the document(s) can be located; (5) Contains the Report on Asset Management Maturity set out in Schedule 13.	(1) (a) This is addressed in the Executive Summary. (b) Refer to 2.6.2 below. (c) Compliance with Attachment A is demonstrated in this compliance matrix. (d) This information is included in Appendix B. (1) (e), (2), (5): AMMAT report is included in Appendix B. (3) We have published the AMP on our website (4) We have addressed these requirements in the AMP, referencing supporting material on our website

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6.1A	Despite clause 2.6.1 (1) Clause 3.11.1(e) and (f) and clauses 12.5-12.7 of Attachment A do not apply in respect of the AMP required to be disclosed before the start of disclosure year 2024; (2) In respect of the AMP required to be disclosed before the start of disclosure year 2024, if an EDB chooses to publicly disclose the information in clauses 17.1-17.6 of Attachment A in a document separate to the AMP in line with clause 2.6.1A(2)(b), the EDB— (a) must publicly disclose that information by 30 June 2023; and (b) is not required to include in its AMP for disclosure year 2024 (publicly disclosed by 31 March 2023) a hyperlink reference to the website where the document(s) can be located. (3) In fulfilling the requirements of clause 2.6.1A(2) above, EDBs are exempt from the director certification requirements set out in clause 2.9 below in respect of the information disclosed in line with the requirements under clauses 17.1-17.6 of Attachment A, contained in either: (a) the EDB's AMP required to be disclosed before the start of disclosure year 2024; or (b) in a document(s) separate to the AMP, which must be made publicly available on the EDB's website by 30 June 2023.	(2) We have addressed these requirements in the AMP, referencing supporting material on our website
2.6.2	The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP— (1) Must provide sufficient information for interested persons to assess whether- (a) assets are being managed for the long term; (b) the required level of performance is being delivered; and (c) costs are efficient and performance efficiencies are being achieved; (2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets; (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	(1)(a) Chapter 2 describes our business, Chapter 3 provides an overview of our network and Chapters 6, 8 and9 discuss the management of our assets. (1)(b) Our levels of performance are set out in Chapter 5 while Chapter 2 explain sets out information on customer preferences. (1)(c) We refer to expected efficiencies in a number of sections, including Chapter 11 (2) We have included a glossary in Appendix A which will aid in understanding. (3) Risk management and resilience is discussed in several sections and Appendix D.
2.6.3	Subject to clause 2.6.4, an EDB may elect to complete and publicly disclose an AMP update, as described under clause 2.6.5, before the start of a disclosure year, instead of an AMP, as described under clause 2.6.1(1), unless the start of that disclosure year is- (1) one year after the start of the DPP regulatory period; or (2) two years before the start of the next DPP regulatory period.	We are publishing a full 2023 AMP.

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6.4	An EDB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.	We are publishing a full 2023 AMP.
2.6.5	For the purpose of clause 2.6.3, the AMP update must— (1) Relate to the electricity distribution services supplied by the EDB; (2) Identify any material changes to the network development plans disclosed in the last AMP under clause 11 and clause 17.5-17.7 of Attachment A or in the last AMP update disclosed under this clause; (3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 12 of Attachment A or in the last AMP update disclosed under this section; (4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b; (5) Identify any changes to the asset management practices of the EDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and (6) Contain the information set out in the schedules described in clause 2.6.6.	(1) Confirmed in Chapter 1 (2) See Chapter 11 (3) See Chapter 11 with background provided in Chapter 9 (4) Included in Chapter 11 (5) Discussed in Appendix B (6) See 2.6.6 below
2.6.6	Each EDB— (1) must, except as provided in subclause 2.6.6(2), before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports— (a) the Report on Forecast Capital Expenditure in Schedule 11a; (b) the Report on Forecast Operational Expenditure in Schedule 11b; (c) the Report on Asset Condition in Schedule 12a; (d) the Report on Forecast Capacity in Schedule 12b; (e) the Report on Forecast Network Demand in Schedule 12c; (f) the Report on Forecast Interruptions and Duration in Schedule 12d; (2) for the purposes of the Report on Forecast Capital Expenditure set out in Schedule 11a required under clause 2.6.6(1)(a), and the Report on Forecast Operational Expenditure set out in Schedule 11b required under clause 2.6.6(1)(b),- (a) is not required to publicly disclose information on cybersecurity expenditure, but must provide that information to the Commission; and	(1) This information is included in Appendix B. (2) Noted (3) Not applicable

REGULATORY REQUIREMENTS		AMP REFERENCE
	(b) in respect of disclosures before the start of disclosure year 2024, is not required to- (i) complete and publicly disclose the information on cybersecurity expenditure in these reports; or (ii) provide the information required on cybersecurity expenditure to the Commission); and (3) must, if the EDB has sub-networks, complete and publicly disclose the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the report.	
2.7	**EXPLANATORY NOTES TO DISCLOSED INFORMATION**	
2.7.2	Before the start of each disclosure year, every EDB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	This information is included in Appendix B.
2.9	**CERTIFICATES**	
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	A copy of the certificate is included in Appendix F.
AMP design		
1.	The core elements of asset management— 1.1 A focus on measuring network performance, and managing the assets to achieve service targets; 1.2 Monitoring and continuously improving asset management practices; 1.3 Close alignment with corporate vision and strategy; 1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets; 1.5 That responsibilities and accountabilities for asset management are clearly assigned; 1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets; 1.7 An emphasis on optimising asset utilisation and performance; 1.8 That a total life cycle approach should be taken to asset management;	1.1 Chapter 5 discusses our service performance. 1.2 Recognition of the need to improve our asset management capabilities and results of our AMMAT assessment are included in Chapter 6. 1.3 Chapter 4 details group strategy and how that aligns with asset management strategy. 1.4 Chapter 4 sets out our business strategies and how these inform asset management practices and performance objectives and targets. 1.5 Chapter 2 discusses our governance structures, governance roles and responsibilities. 1.6 Chapter 3 provides an overview of our network assets. Chapter 9 includes more detailed information.

REGULATORY REQUIREMENTS		AMP REFERENCE
	1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	1.7 Chapters 5 and 8 discuss how we manage asset utilisation. 1.8 Chapter 6 explains our lifecycle based approach to managing our assets. 1.9 Chapter 8 sets out our approach to using non-network solutions.
2.	The disclosure requirements are designed to produce AMPs that— 2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1; 2.2 Are clearly documented and made available to all stakeholders; 2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets; 2.4 Specifically support the achievement of disclosed service level targets; 2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment; 2.6 Consider the mechanics of delivery including resourcing; 2.7 Consider the organisational structure and capability necessary to deliver the AMP; 2.8 Consider the organisational and contractor competencies and any training requirements; 2.9 Consider the systems, integration and information management necessary to deliver the plans; 2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and 2.11 Promote continual improvements to asset management practices.	2.1 The elements of asset management identified in clause 1 are referenced above, while further elements are discussed throughout the AMP itself. 2.2 Our AMP is made available on our website to all stakeholders. 2.3 Our evaluation of our asset management processes is contained in Schedule 13 (Report on Asset Management Maturity) – refer to Appendix B. Asset management capability is discussed in Chapter 6. 2.4 Chapter 5 discusses our service performance and supporting initiatives. 2.5 Chapter 7 discuss risk management in general. Chapter 9 discusses the performance and risk for each individual fleet. 2.6 Works delivery is discussed in Chapters 2 and 6. 2.7 Governance roles are discussed in Chapter 2 and capability is further discussed in Chapter 6. 2.8 Chapters 2 and 6 discuss organisational competencies. 2.9 Chapter 10 discusses our supporting ICT systems. 2.10 We have included a glossary in Appendix A. 2.11 Chapter 4 discusses asset management objectives and strategy. Chapter 6 discusses our asset management capability, including our current capability and planned improvements.

REGULATORY REQUIREMENTS		AMP REFERENCE
Contents of the AMP		
3.	The AMP must include the following-	
	3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	3.1 The Executive Summary provides a brief overview and highlights significant information.
	3.2 Details of the background and objectives of the EDB's asset management and planning processes;	3.2 Chapters 4, 8 and 9 discusses our management strategy and planning approaches.
	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; and 3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	3.3.1 Purpose statement is included in Chapter 1 3.3.2 Chapter 4 sets out our group strategy and how this relates to asset management 3.3.3 Chapter 4 discusses our planning documents. 3.3.4 Chapter 4 sets out our document hierarchy. 3.3.5 Chapter 4 details our strategy and governance.
	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;	Chapter 1 details the period covered by the AMP.
	3.5 The date that it was approved by the directors;	Chapter 1 includes the date it was approved by directors.
	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; and 3.6.4 how conflicting interests are managed;	3.6 Chapter 2 explains our approach to stakeholder management and addresses these points.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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; and 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;	Chapters 2 and 6 explain our governance approaches 3.7.1 Chapter 6 explains our asset management governance approach. 3.7.2 Section 2.2.1 discusses our executive team. 3.7.3 Section 2.2.4 discusses service delivery.
	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; and 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;	3.8.1 We comment on the possible impacts of certain assumptions in Chapter 11 and where forecasts are discussed. These assumptions are qualified where possible. 3.8.2 Significant assumptions are discussed throughout the AMP, including in Chapters 8 and 9. 3.8.3 Not directly applicable. 3.8.4 Sources of uncertainty (and the potential effect of the uncertainty on information) are discussed throughout the AMP. For example, forecast uncertainty in Chapter 11. 3.8.5 Chapter 11 discusses inputs and assumptions underpinning our forecasts.
	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;	We comment on the possible expenditure variance due to the impact of Cyclone Gabrielle recovery on renewal expenditure. We also note that future disclosed forecasts may vary due to efficiency improvements and other improvements to our asset management systems and modelling.

REGULATORY REQUIREMENTS		AMP REFERENCE
	3.10 An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-* *(i) how the asset management strategy is consistent with the EDB's other strategy and policies;* *(ii) how the asset strategy takes into account the life cycle of the assets;* *(iii) the link between the asset management strategy and the AMP; and* *(iv) processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	(i) This is illustrated in Chapter 4 where we explain our strategic framework, our group strategy and asset management policy. (ii) This is explained in Chapter 6. (iv) The link between asset management strategy and the AMP is discussed in Chapter 4. (iv) Chapters 6 and 7 discuss our governance and risk management processes respectively.
	3.11.1 An overview of systems and information management data; *(a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;* *(b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;* *(c) the systems and controls to ensure the quality and accuracy of asset management information; and* *(d) the extent to which these systems, processes and controls are integrated* *(e) how asset management data informs the models that an EDB develops and uses to assess asset health; and* *(f) how the outputs of these models are used in developing capital expenditure projections.*	(i) Renewal drivers such as asset health and asset condition are discussed in Chapters 6 and 9. Chapter 10 provides an overview of our asset management data systems. (ii) Chapter 10 provides an overview of our asset management data systems. Chapter 9 discusses information requirements including our asset management system and asset condition, including details on inspections and reporting on asset condition and performance for each fleet. (iii) Asset management systems discussed in Chapter 10, and improvements discussed in Chapter 6. (iv) System integration is discussed in Chapter 10 (iv) Overarching approach is discussed in Chapter 6 with specific details included throughout Chapter 9. (iv) Overarching approach is discussed in Chapter 6 with specific details included throughout Chapter 9.
	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;	Limitations and initiatives to improve data are discussed in Chapters 6 and 9.

REGULATORY REQUIREMENTS		AMP REFERENCE
	3.13 A description of the processes used within the EDB for- 3.13.1 managing routine asset inspections and network maintenance; 3.13.2 planning and implementing network development projects; and 3.13.3 measuring network performance;	3.13.1 Chapters 6 and 9 set out our operations and maintenance approach in terms of fleet management. Maintenance approaches for fleets are discussed in detail in Chapter 9. 3.13.2 Our approach to developing our network is discussed in Chapter 8. 3.13.3 Performance is discussed in Chapter 5.
	3.14 An overview of asset management documentation, controls and review processes. *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-* *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system;* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system.*	Chapters 4 and 6 discusses our strategy and governance. In particular: • Section 4.5 discusses documentation for our Asset Management System. • Section 4.2 discusses our strategic framework. • Section 4.3.1 discusses our asset management policy. • Section 4.4 discusses our asset management focus areas. • Section 6.4 discusses asset management governance. • Chapter 6 explains how we assess and manage our asset manage capability .
	3.15 An overview of communication and participation processes; *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* *(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	Chapter 2 sets out our communication and engagement processes. (i) Chapter 2 discuss our interactions with external stakeholders (ii) Chapter 2 discuss our internal engagement on in the efficient and cost effective delivery of the asset management requirements.
	3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Expenditure and related charts are set out in constant price New Zealand dollars.
	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.	The structure of the AMP is detailed in Section 1.2.

REGULATORY REQUIREMENTS		AMP REFERENCE
Assets covered		
4.	The AMP must provide details of the assets covered, including-	An overview of assets included in Chapter 3, with more detailed information in Chapter 9 and Appendix C.
	4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including- 4.1.1 the region(s) covered; 4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities; 4.1.3 description of the load characteristics for different parts of the network; 4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	4.1 Service areas are discussed in Chapter 3 and Appendix C. 4.1.1 The regions covered by our network are discussed in Chapter 3. 4.1.2 Major customers are discussed in Section 3.4. 4.1.3 Load characteristics are discussed in Chapter 3 and Appendix C 4.1.4 Set out in Chapter 8.
	4.2 a description of the network configuration, including- 4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the network's distribution substation arrangements; 4.2.5 a description of the low voltage network including the extent to which it is underground; and 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems. *To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.*	Network configuration is discussed in Chapter 3 and Appendix C. 4.2.1 This information is set out in Section 3.2 and Chapter 8 4.2.2 Chapter 3 describes our subtransmission network. The capacity and security ratings of individual zone substations is set out in Chapter 8. 4.2.3 Chapter 3 and Appendix C describe our distribution network. 4.2.4 An overview is provided in Appendix C. 4.2.5 Section 3.3.4 and Appendix C describes our low voltage network. 4.2.6 An overview of secondary systems is provided in Chapter 9. Appendix C includes network maps and a single line diagram.

REGULATORY REQUIREMENTS		AMP REFERENCE
	4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	Not applicable.
	Network assets by category	
	4.4 The AMP must describe the network assets by providing the following information for each asset category- 4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	4.4 Network assets are detailed in Chapters 3 and 9. 4.4.1 These are provided, where relevant, in Chapter 3. 4.4.2 Chapter 9 provides detailed description for each fleet. 4.4.3 These are described individually for each fleet in Chapter 9. 4.4.4 These are described individually for each fleet in Chapter 9.
	4.5 The asset categories discussed in clause 4.4 should include at least the following- 4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); 4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others; 4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.4 other generation plant owned by the EDB.	4.5.1 Chapter 9 discusses our fleets individually. 4.5.2 This is discussed in Section 3.2. 4.5.3 Discussed in Section 3.3.5. 4.5.4 Discussed in Section 3.3.5.
Service Levels		
5.	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Chapter 5 sets out our performance indicators and targets. Where applicable we have indicated whether targets apply for the full planning period.
6.	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	These are set out in Chapter 5.

REGULATORY REQUIREMENTS		AMP REFERENCE
7.	Performance indicators for which targets have been defined in clause 5 should also include- 7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and 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.	7.1 Performance indicators for safety and reliability are discussed in Chapter 5. In addition, we discuss feedback from customers on our performance. Satisfaction measures are broken out into residential and commercial. 7.2 This is discussed in Section 5.6.
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.	Chapter 5 discusses our performance targets and strategies.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Chapter 5 sets out historical performance where these are available and equivalent.
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance. *Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.*	This is discussed for individual targets in Chapter 5.
Network Development Planning		
11.	AMPs must provide a detailed description of network development plans, including—	Network development is discussed in Chapter 8.
	11.1 A description of the planning criteria and assumptions for network development;	Our planning process is discussed in Section 8.3.
	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;	Our planning criteria are discussed in Section 8.3.2.
	11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	Cost efficiency is discussed in a number of sections, including Chapters 5 and 6.
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; and 11.4.2 the approach used to identify standard designs;	Section 6.2.2 discusses our use of standard designs. Chapter 9 discusses assets and designs that are standardised.
	11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Section 8.3.3 discusses our use of customer demand management including ripple control.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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; *The criteria described should relate to the EDB's philosophy in managing planning risks.*	Chapter 8 discusses the role of system demand (capacity) in informing investment decisions. Asset and network planning in terms of asset risk management are discussed in Chapter 7.
	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;	In Chapters 6 and 8 we explain investment drivers and how these align with our objectives and vision.
	11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	11.8 System demand is discussed, and demand forecasts are provided, in Section 8.4. 11.8.1 The methodology used for load forecasting is set out in Section 8.3.1. 11.8.2 Load forecasts are set out in Section 8.4.4. 11.8.3 Network constraints are discussed in Section 8.5. 11.8.4 This is explained in Section 8.3.1.
	11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and 11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Major projects are discussed in Section 8.6 and Appendix C.

REGULATORY REQUIREMENTS		AMP REFERENCE
	11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; *For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.*	Network development investments are discussed in Section 8.6, in particular Section 8.6.1. Further detail on these projects (including alternative options considered and the reasons for choosing the selected option) is set out in Appendix C.
	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; and	Distributed generation is discussed in Sections 3.5 and 8.7.
	11.12 A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address network problems or constraints.	Non-network solutions are discussed in Section 8.8.
Lifecycle Asset Management Planning (Maintenance and Renewal)		
12.	The AMP must provide a detailed description of the lifecycle asset management processes, including—	Our lifecycle management approach is discussed in Chapters 6 and 9.
	12.1 The key drivers for maintenance planning and assumptions;	These are discussed in Section 9.2.2

REGULATORY REQUIREMENTS		AMP REFERENCE
	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;	Our approach to maintenance is set out in Chapters 6 and 9.. 12.2.1 Chapter 9 explains our approach to inspecting and maintaining each category of assets. 12.2.2 Chapter 9 provides this information for each fleet individually. 12.2.3 Forecast maintenance expenditure is included in Chapter 11
	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 that have deferred asset replacements; 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; and	12.3 Refurbishment and renewal is discussed in Chapters 6 and 9. 12.3.1 Chapter 9 provides this information for each fleet individually. 12.3.2 These are addressed in Chapter 6.4. 12.3.3 This is included in Appendix C 12.3.4 This is included in Appendix C 12.3.5 This is discussed in Chapter 9 for each fleet.
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Chapter 9 provides this information for each fleet individually.
	12.5 Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of: 12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and 12.5.2 the rationale for using the approach for each asset category.	12.5.1 Approach to developing capital expenditure projections for lifecycle asset management is set out in Chapters 6 and 9. 12.5.2 The appro Section 11.5 ach for individual asset fleets is set out in Chapter 9.
	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.	Our approach to vegetation management is set out in Chapter 9.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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;	Our overarching approach is discussed in Section Chapter 8.9.
Non-Network Development, Maintenance and Renewal		
13.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including— 13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; and 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	Chapter 10 explains our overarching approach to managing our non-network assets. This includes how we identify the need for investments and operational expenditure. Where these are confirmed we discuss material items of future expenditure.
Risk Management		
14.	AMPs must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events; 14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and 14.4 Details of emergency response and contingency plans.	14.1 Risk management is discussed in Chapter 7. 14.2 We discuss our methodology and key risks in Chapter 7 14.3 We discuss our methodology in Section 8.5.2 and include planned controls (where identified) in Appendix D. 14.3 We discuss emergency response and contingency plans in Section 8.5.1
Evaluation of performance		
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including-	
	15.1 A review of progress against plan, both physical and financial; *referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;* *commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and*	This is addressed in Chapter 11.

REGULATORY REQUIREMENTS		AMP REFERENCE
	commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	
	15.2 An evaluation and comparison of actual service level performance against targeted performance; *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	Chapter 5 discuss our network reliability performance, our primary service performance measure. We have also set out updated reliability measures and new metrics.
	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.	In Chapter 6 we discuss the implications of our AMMAT result and set our improvement initiatives.
	15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Chapters 5 and 6 set out improvement initiatives for performance and asset management capability, respectively.
Capability to deliver		
16.	AMPs must describe the processes used by the EDB to ensure that- 16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	16.1 Chapter 4 discusses our objectives, strategy and governance practices that guide our decision-making. 16.2 An overview of our ownership and governance structure is included in Chapter 2 along with roles and responsibilities.
Requirements to provide qualitative information in narrative form		
17	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
	17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	We explain our approach to notifying customers about outages in Chapter 2.

REGULATORY REQUIREMENTS		AMP REFERENCE
	Voltage Quality	
	17.2 a description of the EDB's practices for monitoring voltage, including:	
	17.2.1 the EDB's practices for monitoring voltage quality on its low voltage network;	This is discussed in Chapter 8.
	17.2.2 how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	We explain our approach to notifying customers about voltage issues in Chapter 2.
	17.2.3 how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	We explain our approach to notifying customers about voltage issues in Chapter 2.
	17.2.4 any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	This is set out in Chapter 2.
	Customer service practices	
	There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.	
	17.3 a description of the EDB's customer service practices, including:	This is discussed in Chapter 2.
	17.3.1 the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	We explain our customer satisfaction performance and related activities in Chapters 2 and 5.
	17.3.1 the EDB's approach to planning and managing customer complaint resolution;	We explain our approach to customer complaints in Chapter 2
	Practices for connecting new consumers and altering existing connections	
	17.4 a description of the EDB's practices for connecting consumers, including:	We explain our approach to customer connections in Chapter 2
	17.4.1 the EDB's approach to planning and management of-	We explain how we manage the planning and management of customer connections in Section 3.4.5
	17.4.1(a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	We explain our approach in Section 3.4.5
	17.4.1(b) alterations to existing connections (offtake and injection connections);	We explain our approach in Section 3.4.5

REGULATORY REQUIREMENTS		AMP REFERENCE
	17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections;	We discuss our approach to fair pricing in Section 5.6.1
	17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections; and	We explain our approach in Section 3.4.5
	17.4.4 commonly encountered delays and potential timeframes for different connections.	This is discussed in Section 3.4.5
	New connections likely to have a significant impact on network operations or asset management priorities	
	The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment.	
	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:	This is discussed in relation to our load forecasting approach in Chapter 8.
	17.5.1(a) how the EDB measures the scale and impact of new demand, generation, or storage capacity;	This is discussed in relation to our load forecasting approach in Chapter 8.
	17.5.1(b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account;	We explain our approach in Section 8.3.1
	17.5.1(c) how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	We explain our approach in Section 8.3.1
	17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	This is discussed in relation to our identification of network constraints, discussed in Section 8.3.
	Innovation practices	
	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;	This is discussed in Section 8.8.6
	17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	These are primarily based on our 'BAU' desired outcomes discussed in Chapters 4 and 5.

REGULATORY REQUIREMENTS		AMP REFERENCE
	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;	This is discussed in Section 8.8.6
	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	This is discussed in Section 8.8.6
	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.	This is discussed in Section 8.8.6
	17.6 For the purpose of disclosing the information required under clauses 17.6.117.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	Noted

APPENDIX F. DIRECTOR'S CERTIFICATE

We, Mark Trigg and Michael James, being directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a 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 Northpower Limited's corporate vision and strategy and are documented in retained records.

Director	Director
29 March 2023	29 March 2023
Date	Date

Northpower

Head Office:
Northpower Limited 28
Mt Pleasant Road
Raumanga, Whangārei 0110
New Zealand

Postal Address:
Northpower Limited
Private Bag 9018
Whangārei Mail Centre 0148
New Zealand

Ph: 09 430 1803
Fax: 09 430 1804
Email: info@northpower.com
www.northpower.com