mainpower

2026

Asset Management Plan

mainpower

Welcome to MainPower.
We’re delighted that you’re here.

Waiau

Strategic overview

Our commitment to you

We are MainPower.
We are a consumer-trust-owned electricity distribution business proudly serving North Canterbury for 100 years. We connect the lives of nearly 90,000 people across Waimakariri, Hurunui, and Kaikōura, delivering electricity to more than 46,000 homes and businesses.

Your network at a glance

As your electricity distributor, we carry the responsibility of keeping your lights on, today and tomorrow. This Asset Management Plan (AMP) represents our commitment to you: **reliable power and an affordable future for everyone in our community.**

This plan has been shaped by what you told us matters most. Through extensive engagement with customers across our region, you've been clear about your priorities:

- **Reliability is paramount;** you want the power to stay on.
- **Affordability matters;** rising costs are a real concern.
- **Safety is non-negotiable;** for your families and our people.
- **Resilience is essential;** our network must withstand severe weather.

We have listened, and this plan reflects your expectations.

Connections	**46,000+**
Circuit length	**5,800 km**
Service area	**10,000 km²**
Peak demand	**115 MW**

What this means for your power bills

The bottom line: Over the next 10 years, we will invest approximately $521 million in maintaining and improving your electricity network. This investment will deliver dependable electricity at the lowest possible cost while preparing for future growth.

The Bottom Line

$521 million

Where your dollar goes

Your investment delivers:

- continued reliable power supply with 99.9% availability
- network capacity to support regional growth in Rangiora, Kaiapoi, Woodend, and surrounding areas
- improved resilience against severe weather and natural hazards
- support for new technologies like electric vehicles (EVs) and solar panels
- ongoing safety for communities and our people.

Asset Management Plan 2026

Strategic overview

How we have shaped this plan around you

Your voice has guided many of the decisions in this plan. Here's what you told us, and how we've responded:

Customer investment priorities

Reliability:
"Keep the lights on"

What you said:

Reliability is your top priority. In our Customer Engagement Survey, customers allocated 34% of preferred investment to improving reliability – more than any other area. Most customers rate their power supply as reliable, but you want us to maintain and improve this performance.

Our response:

- We will maintain SAIDI (average outage duration) targets of 381.8 minutes per year and SAIFI (average outage frequency) targets of 1.89 interruptions per year.[1]
- We are investing $15 million annually in asset replacement and renewal to prevent failures before they occur.
- We are implementing advanced network monitoring tools to identify and address issues proactively.
- We are automating switchgear across the network to restore power faster when faults occur.

[1] SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index.

Percentage allocation of priorities as identified during our AMP engagement sessions.

Affordability:
"Keep costs fair and manageable"

What you said:

The rising cost of living is a real concern. Most customers don't want to pay more for improvements if it means higher bills. You want value for money.

Our response:

- We have balanced our investment programme to deliver reliability improvements while managing cost impacts.
- We are maintaining strong cost efficiency, targeting performance below the 75th percentile for both operating and capital expenditure per customer compared with other networks.
- We are using risk-based decision-making to invest where it matters most, avoiding unnecessary gold-plating.
- Our investment in innovation and digital tools will drive long-term efficiency savings.

Resilience:
"Prepare for extreme weather"

What you said:

In our Customer Engagement Survey, customers allocated 24% of preferred investment to resilience. You've experienced severe storms and understand that climate change means more extreme weather events ahead.

Our response:

- We are strengthening critical infrastructure in high-risk areas.
- We are upgrading vegetation management using artificial intelligence (AI) and satellite technology to identify trees that pose risks before they cause outages.
- We are investing in network redundancy so that alternative supply paths are available during major events.
- We are improving our emergency response capability with better tools and processes.

Future technology:
"Support our choices"

What you said:

You're aware of new technologies like EVs and solar panels, though most of you (81%) aren't prepared to pay more for network upgrades to support them yet. You want the network ready when you choose to adopt these technologies.

Our response:

- We are monitoring technology trends and preparing the network for gradual adoption.
- We are investing in smart meter data analytics to understand low-voltage network capacity.
- We are developing flexibility solutions that will help manage peak demand as EV charging increases.
- We are ensuring new infrastructure is designed to accommodate future technology needs.

Strategic overview

Our strategic direction

Our network development strategy is built around five key commitments to you:

1

Enable and support regional growth:

As North Canterbury grows, your electricity supply will keep pace.

2

Provide appropriate security of supply:

Your power will be reliable, with backup systems ready when needed.

3

Facilitate continual improvement in network reliability:

We are continually working to reduce the frequency and duration of outages.

4

Standardise subtransmission and distribution assets:

Using standard designs and equipment keeps costs down and makes maintenance more efficient.

5

Facilitate consumer-driven technology adoption:

Whether it's solar panels, EVs, or batteries, our network will support your choices.

The asset lifecycle

Major projects map

Strategic overview

Major investments over the next decade

We have planned the following strategic investments to address capacity constraints, improve reliability, and prepare for growth.

Major projects
FY27–FY36

$101 million

Major investments over the next decade

FY26 FY27 FY28 FY29 FY30 FY31 FY32 FY33 FY34 FY35 FY36 FY37

Project	Description	Timeframe
Waimakariri Coldstream 66 kV subtransmission circuit upgrade	Long-term capacity solution.	FY28–FY31
Waimakariri Coldstream zone substation	66 kV substation east of Rangiora to support residential and commercial growth in Woodend, Ravenswood, and Pegasus areas.	FY27–FY29
Hurunui Amberley zone substation upgrade	Capacity increase to support industrial and residential growth.	FY26–FY27
Hurunui Amberley 66 kV conversion	Long-term capacity solution.	FY34–FY36
Hurunui Hanmer Springs zone substation upgrade	Tourism growth and residential development support.	FY27–FY31
Hurunui Hanmer Springs subtransmission upgrade	Security of supply improvement.	FY29–FY30
Hurunui Mouse Point zone substation upgrade	Long-term capacity solution.	FY32–FY34
Hurunui Hawarden zone substation upgrade	Agricultural intensification support.	FY31–FY33
Kaikōura Cheviot to Kaikōura 66 kV circuit	Improved resilience following earthquake recovery.	FY26–FY28
Kaikōura Kaikōura zone substation upgrade	Tourism growth and seismic resilience.	FY29–FY32
Network reinforcement $35 million	Targeted reliability improvements, including: • Island Road feeder extension bringing more capacity to southeast Kaiapoi • Rangiora North feeder bypass addressing bottlenecks on East Belt • Fernside network reconfiguration for more reliable supply • Automation of switchgear for faster fault response • Woodend, Loburn, and coastal area reinforcements	FY27–FY36
Asset replacement & renewal $160 million	Systematic replacement of ageing assets before they fail: • Overhead line conductors and poles • Switchgear and protection systems • Power transformers • Underground cables • Secondary systems	FY27–FY36
Maintenance $96 million	Preventive care to extend asset life and prevent failures: • Vegetation management using AI-powered risk assessment • Routine inspections and condition monitoring • Corrective maintenance addressing emerging issues • Emergency response capability	FY27–FY36

Asset Management Plan 2026

Understanding our network and challenges

Network overview

Service territory
10,000 km² across Waimakariri, Hurunui, and Kaikōura

10,000 km²

Network length
5,300 km of overhead and underground lines

5,300 km

Connected customers
46,000+ residential and business connections

46,000+

Peak demand
115 MW (summer peak driven by irrigation and cooling)

115 MW

Network configuration
Predominantly overhead rural network

76%

Key challenges we are managing

1. Regional growth

North Canterbury, particularly the Waimakariri area, continues to experience strong population and economic growth. Rangiora, Kaiapoi, Pegasus, and Woodend are expanding rapidly due to proximity to Christchurch and improved transport links. This growth drives demand for new connections and increased network capacity.

2. Climate change and extreme weather

Our predominantly overhead network spanning large rural areas is exposed to increasingly severe weather events. Climate change is driving more frequent and intense storms, requiring targeted resilience investments and improved vegetation management.

3. Aging asset base

A significant portion of our network was installed in the 1960s–1980s and is now reaching end-of-life. We must systematically replace these assets before they fail, balancing investment timing with cost impacts.

4. Technology transition

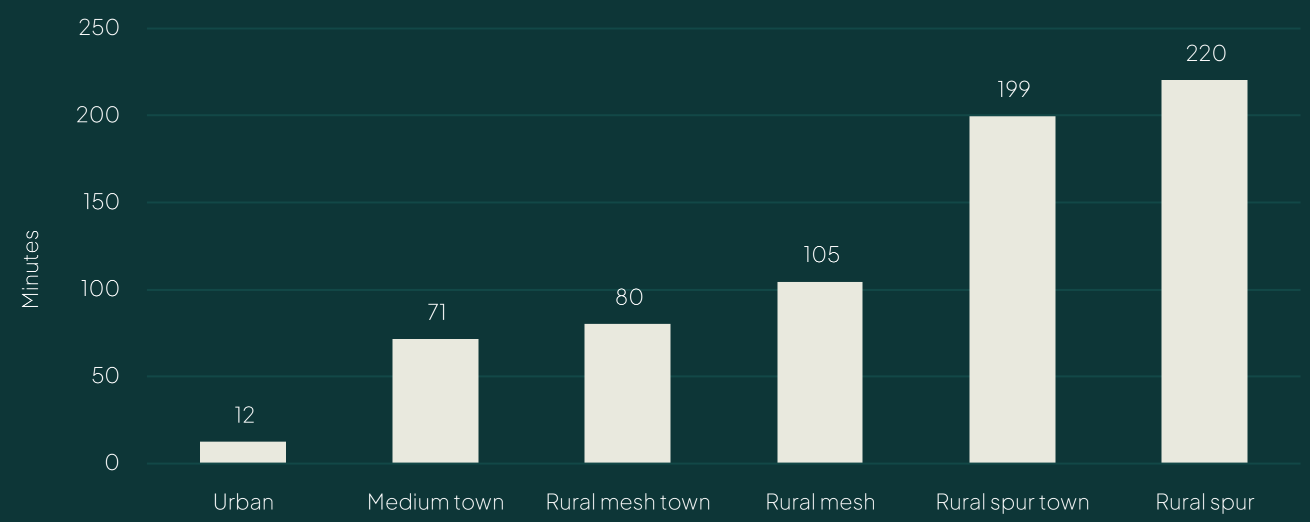
The electricity sector is transforming with distributed generation (e.g. rooftop solar), EVs, battery storage, and demand flexibility. While adoption is currently modest in our region, we must prepare the network for gradual uptake over the planning period.

5. Cost pressures

Material costs, labour rates, and compliance requirements continue to rise. We must deliver our work programme efficiently while maintaining quality and safety standards.

Network performance by area

Average outage duration in FY25, by network segment



How we manage risk to deliver value

We recognise the ongoing trade-off between reducing risks and maintaining affordability. Every decision balances safety, reliability, and cost.

Our risk management framework

- Identify risks through assessments across all activities
- Assess likelihood and impact using quantitative risk modelling
- Prioritise based on risk appetite aligned with customer priorities
- Mitigate through targeted controls and investments
- Monitor effectiveness and adjust as conditions change

Key risks we are managing

- **Safety risks:** Public safety around electricity infrastructure, worker safety
- **Network risks:** Asset failure, capacity constraints, supply security
- **External risks:** Severe weather, seismic events, third-party damage
- **Business risks:** Regulatory compliance, financial sustainability, cyber security

Our risk appetite

We are committed to keeping risks as low as reasonably practicable. This means:

- Averse to safety risks that could cause harm to the public and our workers
- Low appetite for network reliability impacts on urban customers
- Moderate appetite for rural network reliability given cost–benefit considerations
- Balanced approach to growth and technology transition investments

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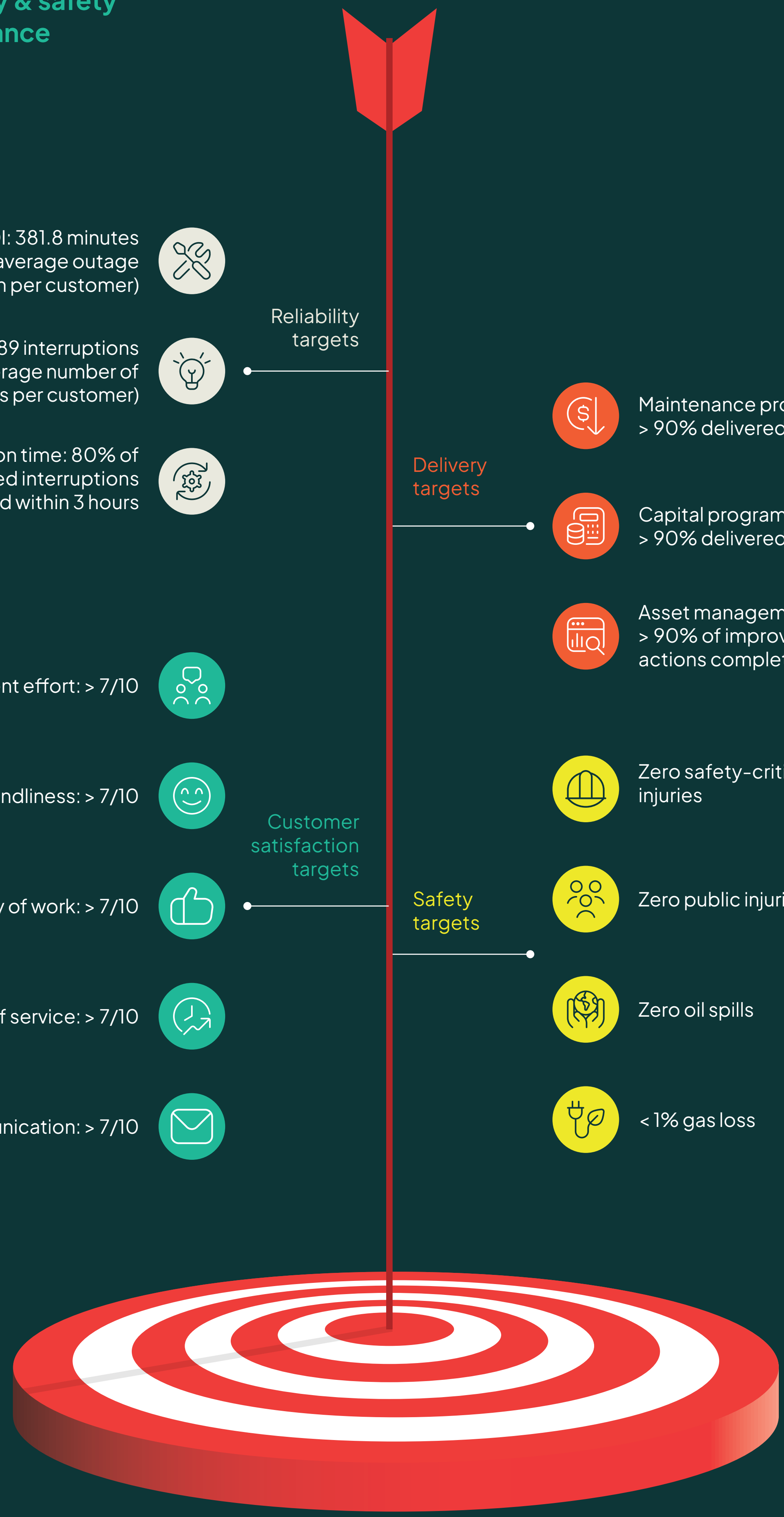
Strategic overview

Our performance commitments

Your reliability performance

Reliability & safety performance



Reliability targets

- SAIDI: 381.8 minutes per year (average outage duration per customer)
- SAIFI: 1.89 interruptions per year (average number of outages per customer)
- Restoration time: 80% of unplanned interruptions restored within 3 hours

Delivery targets

- Maintenance programme: > 90% delivered to budget
- Capital programme: > 90% delivered to budget
- Asset management maturity: > 90% of improvement actions completed

Customer satisfaction targets

- Engagement effort: > 7/10
- Staff friendliness: > 7/10
- Quality of work: > 7/10
- Timeliness of service: > 7/10
- Communication: > 7/10

Safety targets

- Zero safety-critical injuries
- Zero public injuries
- Zero oil spills
- < 1% gas loss

Asset Management Plan 2026

Innovation and capability

To deliver this plan efficiently, we are investing in people, systems, and innovation.

Innovation highlights

Innovation via digital transformation

- **AI-powered vegetation management:** Predicting tree growth and risk using satellite imagery and machine learning
- **Smart meter analytics:** Understanding low-voltage network performance and customer energy use patterns
- **Enhanced geographic information system (GIS) applications:** Better asset data management and decision support
- **Digital data capture:** Real-time field data collection for accurate asset records
- **Customer portal:** Online project tracking and communication

Development of our people

- Maintaining skilled internal teams for core activities
- Strategic contractor partnerships for specialised work and peak demand
- Ongoing training and competency development
- Succession planning for critical roles

Asset management systems

- ISO 55001-aligned practices[2]
- Risk-based decision frameworks
- Data-driven asset health monitoring
- Continual improvement culture

[2] *ISO 55001 is an international standard that specifies the requirements for an asset management system.*

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Expenditure summary

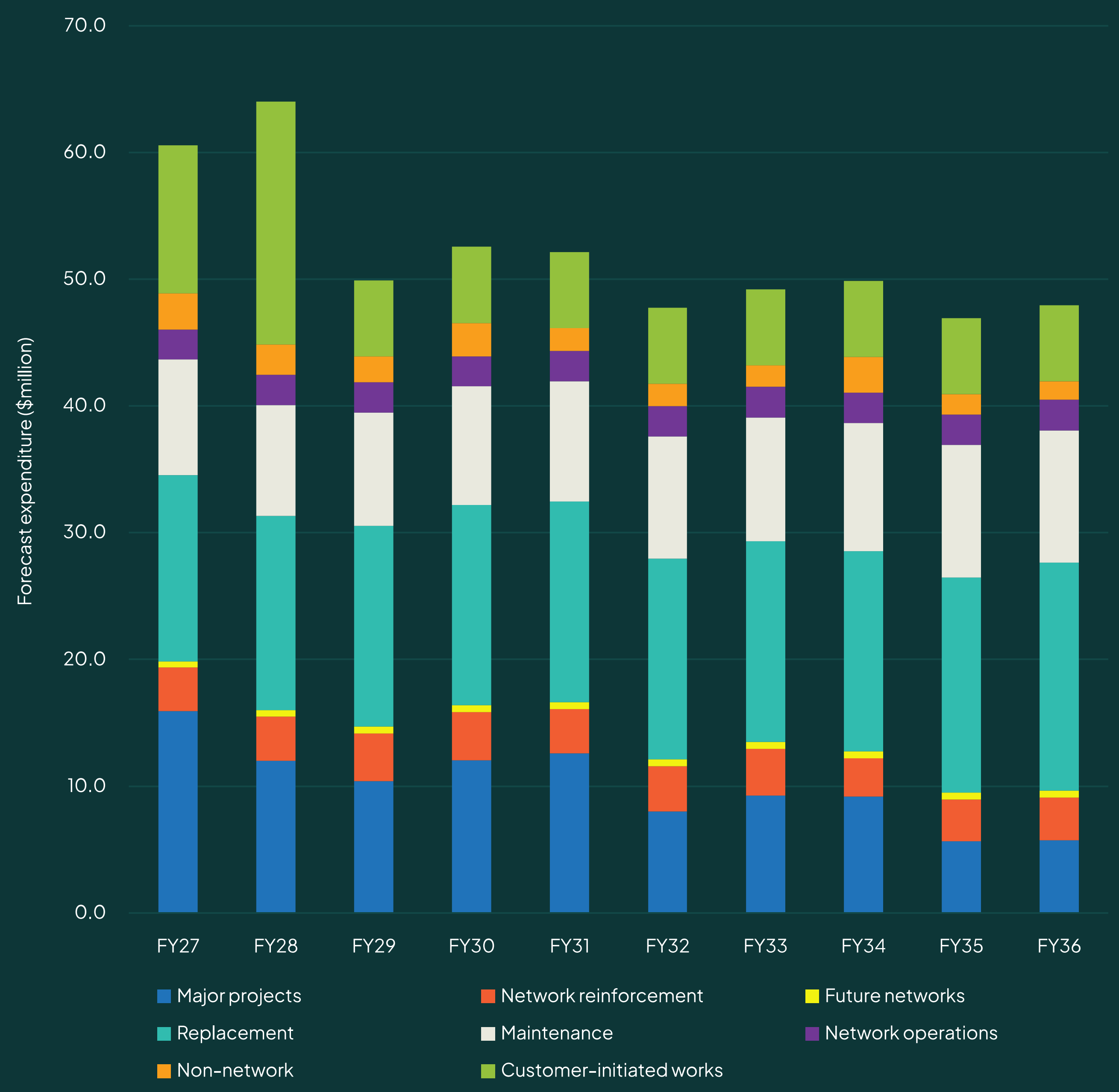
Category	FY27 budget	10-year total
Major projects	$15.9 million	$101 million
Network reinforcement	$3.4 million	$35 million
Future networks (operating expenditure (OPEX))	$0.5 million	$5 million
Asset replacement & renewal	$14.7 million	$160 million
Maintenance (OPEX)	$9.1 million	$96 million
Network operations (OPEX)	$2.4 million	$24 million
Customer-initiated works	$11.7 million	$79 million
Non-network assets	$1.3 million	$6 million
Non-network OPEX	$1.5 million	15 million
Total	**$60.6 million**	**$521 million**

Note *All figures in constant FY26 prices*

Total network expenditure (FY27–FY36)

$521 million

10-year investment programme



Expenditure profile

Investment is slightly higher in the early years of the forecast FY27–FY36 reflecting major project delivery of committed projects, and then again towards the mid-term of the forecast when the subtransmission upgrade and zone substation upgrade projects are being implemented. This profile balances addressing immediate capacity constraints with longer-term security requirements while maintaining uniform expenditure to ensure affordability.

Asset Management Plan 2026

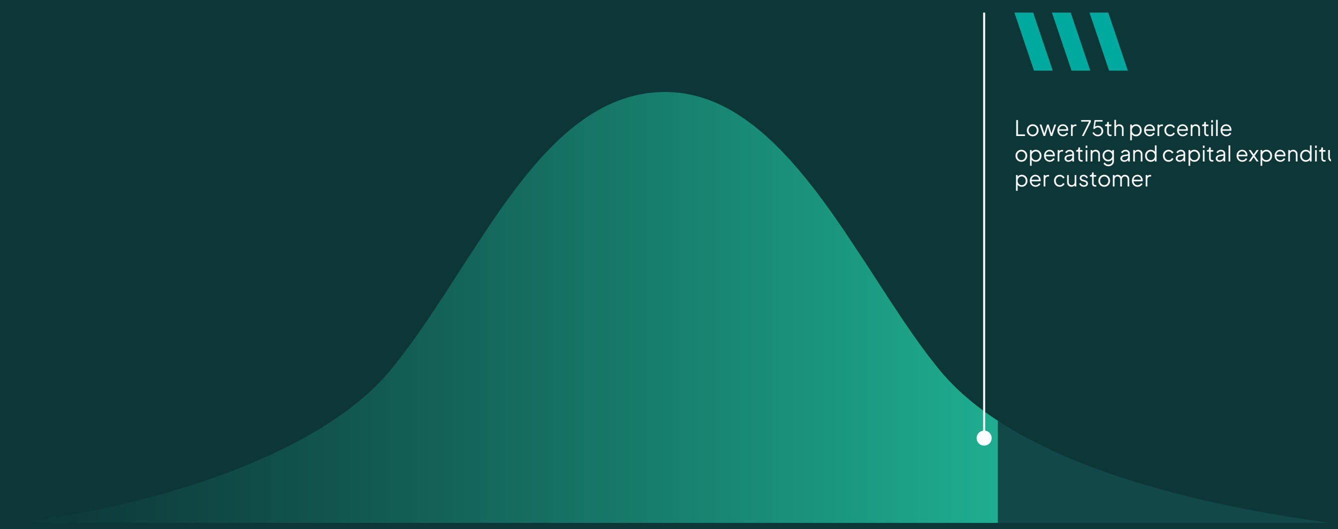
Strategic overview

Value for money

We are committed to delivering maximum value from every dollar invested. Our approach centres on three fundamental principles:

1. Cost efficiency

We actively manage our costs to deliver competitive performance compared with peer networks across New Zealand. Our targets position us below the 75th percentile for both operating and capital expenditure per customer, demonstrating our commitment to efficient service delivery. Benchmarking against comparable electricity distribution networks nationally allows us to identify opportunities for improvement and adopt industry-leading practices that benefit our customers.



2. Prudent planning

Investment decisions are guided by risk-based prioritisation, directing resources to areas where they deliver the greatest benefit for safety, reliability, and customer value. We apply whole-of-life cost analysis to major decisions, considering not just initial capital costs but also ongoing maintenance, operational efficiency, and eventual replacement. Our planning process systematically evaluates non-network alternatives such as demand management and distributed generation before committing to traditional network solutions. We stage investments carefully to align with demand growth timing, avoiding premature expenditure while maintaining adequate capacity for future needs.

3. Continual improvement

Our ISO 9001[3] quality management system provides the framework for systematic improvement across all business activities. We regularly assess our asset management maturity using the Commerce Commission's assessment tool, developing targeted improvement plans to address capability gaps. Innovation programmes explore new technologies and methods that can drive efficiency gains, from AI-powered vegetation management to digital data capture in the field. We maintain a culture of regular review and refinement, learning from our performance and adapting our practices to deliver better outcomes for customers.

[3] *ISO 9001 is an international standard for quality management systems.*

Our path forward

This AMP sets out our direction for the next decade. We understand that circumstances will change, and we will adapt our plans as needed while maintaining our commitment to reliable and affordable electricity for North Canterbury.

For households

We will maintain reliable electricity supply, with most outages restored within hours. The network will have capacity for new technologies like EVs as you choose to adopt them. Our investment programme balances necessary improvements with careful cost management.

For communities

Our investment will support population and economic growth across the region. We will continue improving network resilience against severe weather and remain committed to safety and environmental responsibility.

For businesses

Network capacity will be available to support your operations and growth. We will maintain service reliability and work with you to deliver connection projects that meet your needs.

Strategic overview

How to provide feedback

This is your AMP. We welcome your feedback and will continue engaging throughout the period to ensure we are meeting your evolving needs.

Contact us

Web

www.mainpower.co.nz

Email

info@mainpower.co.nz

Phone

0800 30 90 96

Address

172 Fernside Road, Rangiora 7400

Asset Management Plan 2026


Waiau

CEO message

Chief Executive's message

Tēnā koutou katoa,

It is my privilege to present our 2026 AMP as Chief Executive, having joined the organisation in early 2026. This plan sets out our commitment to the communities of Waimakariri, Hurunui, and Kaikōura over the coming decade: to deliver safe, reliable, and sustainable electricity that supports our region to thrive.

Responding with accountability

The severe weather events of late 2025 tested both our network and our communities. Extended outages in areas such as Culverden, Hanmer Springs, and the Lees Valley and the disruption to critical services like water supply were unacceptable outcomes that demand our urgent response.

This plan reflects that response through accelerated investment in climate adaptation and network resilience. We are strengthening vulnerable circuits, enhancing our emergency response capabilities, and deploying smart technology that enables faster fault detection in remote areas. Our approach is informed by enhanced climate modelling and focused on protecting the essential services our communities depend on.

Creating a smarter future to deliver local value

Our vision extends beyond maintaining the status quo. Through our MPowered Future strategy, we are positioning MainPower to support North Canterbury's economic growth, enable the transition to a low-carbon economy, and adapt to rapidly evolving customer needs.

The region's strong development is driving load growth, with electrification of transport and heating increasing demand for network capacity. Simultaneously, customers are becoming active participants in the energy system – generating their own solar power, installing batteries, and seeking greater control over their energy use. Our network must evolve to support these changes.

Balancing reliability, sustainability, and affordability

Customer engagement confirms that reliability remains the top priority for our communities. Through surveys and direct consultation, customers have told us they value resilience against extreme weather events and network capability to support future technologies.

Our capital expenditure programme of $47 million forecast for FY27 reflects these priorities while maintaining focus on affordability. We are investing in substation replacements, network reinforcement, smart infrastructure, and targeted resilience improvements. Every project is evaluated against robust cost-benefit criteria to deliver optimal value.

This is the energy trilemma in action: balancing the imperative for reliable supply against the requirements of decarbonisation and the necessity of managing costs for our communities.

Technology as an enabler

Digitalisation is central to our strategy. Smart metering and advanced network monitoring provide unprecedented visibility into network performance, enabling more efficient operations, faster fault response, and better integration of distributed energy resources.

These technologies serve practical purposes: reducing operational costs, improving customer information, enabling faster restoration after outages, and supporting the flexible, responsive network our communities will require as the energy sector continues to evolve.

Our people and our region

Our capability rests in our people, from line mechanics to engineers, customer service teams, and support staff, who together deliver essential services under all conditions. We remain committed to workforce development, apprenticeships, and maintaining the strong safety culture that protects our team and the public.

Beyond our operations, we recognise our broader role in North Canterbury's social and economic fabric. Our values guide both how we work and how we contribute to our communities through partnerships and support.

A confident path forward

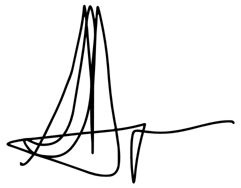
The decade ahead presents clear challenges: ongoing climate impacts, growth-driven capacity requirements, evolving customer expectations, and increasingly rigorous regulatory obligations. We approach these with confidence, grounded in robust planning and genuine commitment to serving our communities well.

This AMP is our roadmap for that decade. It balances the lessons learned from recent challenges with the opportunities presented by technological change and regional growth. It prioritises investments that matter most to our customers while maintaining the financial discipline our communities expect.

Our purpose is unchanging: to deliver the reliable, sustainable electricity supply that underpins everything our region does. The lights staying on. Businesses operating without interruption. Farms and homes powered safely and efficiently. Communities that can depend on their electricity infrastructure, even in the toughest conditions.

I look forward to working with our customers, our Board, our team, and our stakeholders to deliver on this commitment.

Ngā mihi nui,



Sean Horgan
Chief Executive

MainPower New Zealand Limited
March 2026

Asset Management Plan 2026

Contents

Mt Grey

1
Your network, your priorities

Some of the MainPower at Head Office

This section explains how we have shaped our Asset Management Plan (AMP) around what matters most to you. We show you how the network has been performing, what you have told us about your priorities, and how we are planning for the future based on your feedback and the growth happening across North Canterbury.

What you will find in this section

- How we listen to you and involve you in our planning
- What you have told us matters most
- How reliable your power supply has been
- The service standards we commit to delivering
- How you can connect to the network and resolve any concerns
- How we measure our performance against industry peers

1.1 Your voice shapes our plan

Listening to you is at the heart of how we plan for the future. Every major decision in this AMP has been shaped by what our customers and community told us matters most. We do not work in isolation. We actively seek your input, understand your concerns, and respond to your priorities.

We engage with a wide range of people who have an interest in our network – from the customers who rely on it daily, to the communities we serve, to the organisations we work with to deliver electricity safely and reliably. Understanding what each group needs helps us make better decisions about how we invest in and manage your network.


Rangiora

1.1.1 Who we engage with

We recognise that different groups have different interests in our network. Figure 1.1 shows the diverse stakeholders who shape our planning.

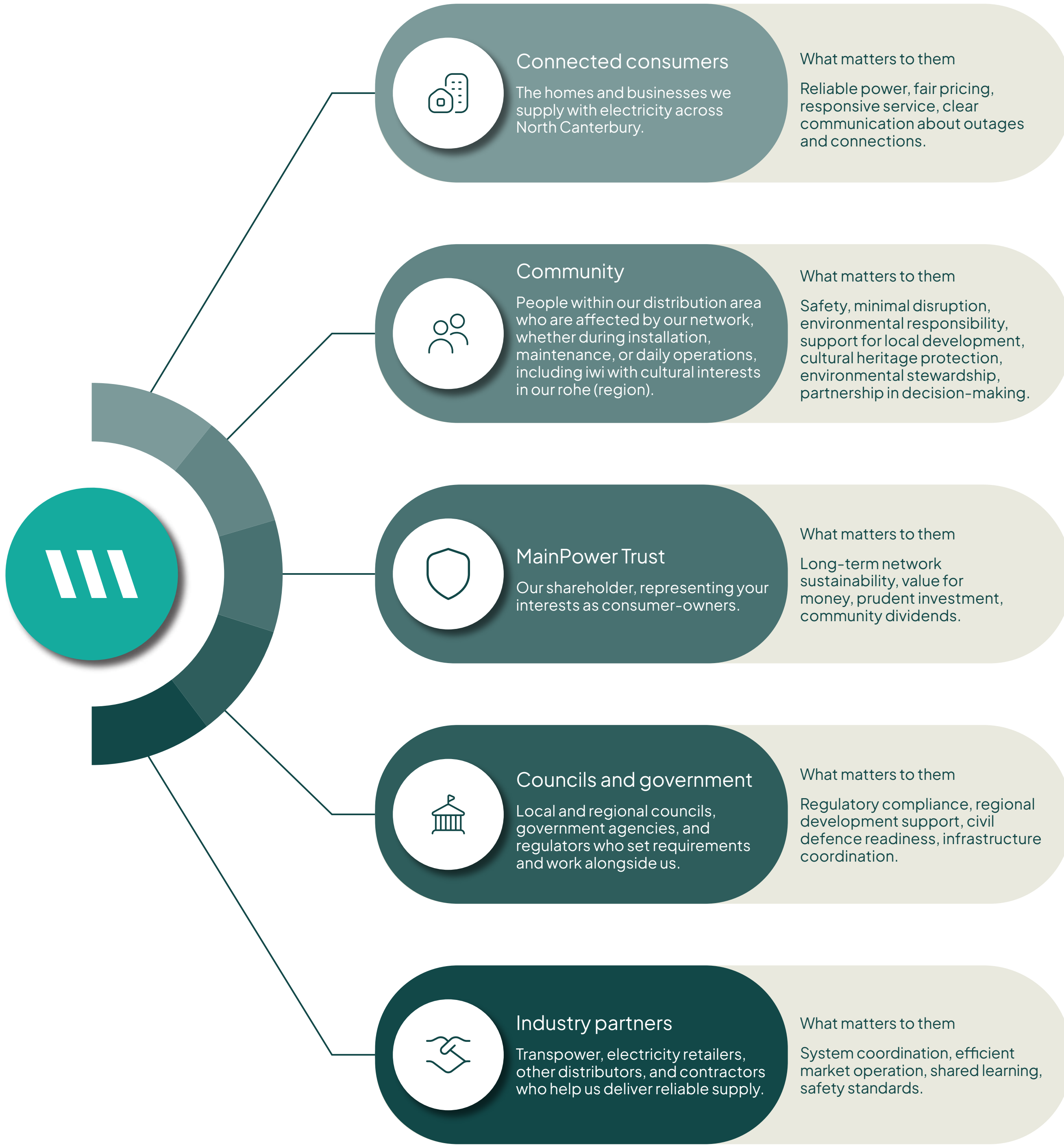


Figure 1.1 Our stakeholders

1.1.2 How we listen and respond

We use multiple channels to understand what matters to each group, from large-scale customer research to one-on-one conversations. Table 1.1 shows how we engage with different stakeholders and, critically, what they told us and how we have responded in this plan.

Table 1.1 Customer engagement methods

Stakeholder group	How we engage	What we heard	How we have responded
Connected consumers	• AMP Customer Engagement Quantitative surveys (925 responses FY25) • AMP Customer Satisfaction Survey (ongoing at service touchpoints) • Customer Pulse Survey (annual, minimum 400 responses) • World Café style AMP Customer Engagement workshops (20–24 participants per session, three regional sessions) • Direct feedback via customer service • Annual meetings and public sessions	• Reliability is customers' top priority (34% of preferred investment) • 86% of customers rate supply as reliable or very reliable • Safety and resilience against extreme weather both matter (24% allocation for each) • Most customers (81%) are not willing to pay significantly more for new technology support • Most customers (65%) prefer no change to current pricing or outage levels • Only 38% of customers are satisfied with price (93% rate price as important) • Communication during outages is important: customers want 1-week notice for planned outages, and notice within 1 hour for unplanned outages • Customer satisfaction challenges: timeliness (6.4/10), quality (5.3/10), and website (5.4/10) below target of 7.0, but friendliness strong (7.4/10)	• Maintained reliability (SAIDI/SAIFI)[*] targets balancing reliability and cost (381.8 minutes, 1.89 interruptions) • Focused investment on reliability (34%) and resilience (24%) as priority areas • Enhanced outage notification system (short messaging service (SMS) alerts, online mapping, advance notice protocols) • Service Delivery Team resourcing to improve timeliness and communication • Technology investment only where proven value (e.g. smart meter analytics)
Community & representative groups	• Consumer feedback/ interactions • Forums and working groups • One-on-one meetings with community leaders • Public consultations on major projects • Submissions on discussion papers • Consultation on projects affecting culturally significant areas (wāhi tapu) • Participation in regional resource management processes • Consultation required – under Heritage New Zealand Pouhere Taonga Act 2014 and Resource Management Act 1991	• Safety messaging: 89% recall at least one safety message (tree trimming and storm preparation most recalled) • Concerns about safety around worksites and infrastructure • Interest in corporate social responsibility and community contribution • Desire for transparent communication during outages • Protection of wāhi tapu and cultural sites • Environmental protection of taonga and waterways	• Zero public safety incidents achieved (FY25 target) • Enhanced safety protocols and public communication campaigns • Continued sponsorship and community programmes (MainPower Community Fund) • Improved outage notification system (SMS, website outage map, social media) • Cultural protocols when working near culturally significant sites • Proactive consultation during network planning and major project development
MainPower Trust (shareholder)	• Consumer feedback/ interactions • Forums and working groups • One-on-one meetings with community leaders • Public consultations on major projects • Submissions on discussion papers	• Deliver secure and reliable supply • Maintain and grow shareholder value • Prudent risk management approach • Innovation that delivers value	• Reliability targets maintained (SAIDI 381.8 minutes, SAIFI 1.89 interruptions) • Balanced investment programme maintaining efficient cost structure • Risk register and mitigation planning (ISO 31000:2018 framework,[†] bow-tie methodology for 10 safety-critical and 5 business-critical risks) • Technology investments focused on proven return on investment
District & regional councils	• Consultation on district plans • Coordination meetings on major projects • Joint infrastructure planning	• Coordinate infrastructure investment with roading and development • Support regional economic development and growth • Environmental protection and compliance	• Integrated planning with Woodend Bypass and roading projects (referenced in growth areas) • Network development aligned with district growth projections • ISO 14001:2015 environmental management system[†‡] • Compliance with Resource Management Act 1991 and local council requirements
Industry partners	• Joint planning with Transpower (operational interface) • Retailer liaison meetings (customer feedback/ interactions, industry collaboration, informal discussions, one-on-one meetings) • Industry forums and working groups • Participation in industry (including membership in Electricity Engineers' Association) • Submissions on discussion papers • Disclosure requirements	• Coordinated investment to avoid duplication • Reliable data exchange and system interfaces • Collaborative approach to industry challenges	• Long-term planning investigation with Transpower • Enhanced data systems and smart meter integration • Active participation in Electricity Engineers' Association and industry submissions

** SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index.*

† ISO 31000:2018 is an international standard that provides principles and guidelines for risk management.

‡ ISO 14001:2015 is an international standard for environmental management systems.

1.1.3 Managing conflicting interests of our stakeholders

Sometimes different stakeholders want different things. Our role is to balance these competing priorities in a way that delivers the best overall outcome for North Canterbury.

Example 1: Reliability vs affordability

Some customers want the highest possible reliability regardless of cost, while others prioritise keeping bills low. We balance this by setting service levels that meet the expectations of most customers (informed by surveys showing 89% satisfaction with current reliability), while targeting investment at the worst-performing parts of the network where improvements deliver the greatest benefit.

Example 2: Growth vs existing network

New developments require network extensions and upgrades, but we must maintain investment in the existing network for current customers. Our capital contributions policy allocates costs fairly between new and existing customers, while our investment plan prioritises both growth and renewal.

Example 3: Planned outages vs operational needs

Customers want minimal disruption, but essential maintenance requires planned outages. We minimise planned interruptions by scheduling work during low-demand periods, providing advance notice (48 hours minimum), and completing multiple tasks during single outages wherever possible.

How we make these decisions:

- Customer research and surveys to understand priorities
- Cost-benefit analysis to assess options objectively
- Transparent explanation of trade-offs
- Regulatory framework providing guidance on service standards
- Trust governance oversight of major strategic decisions

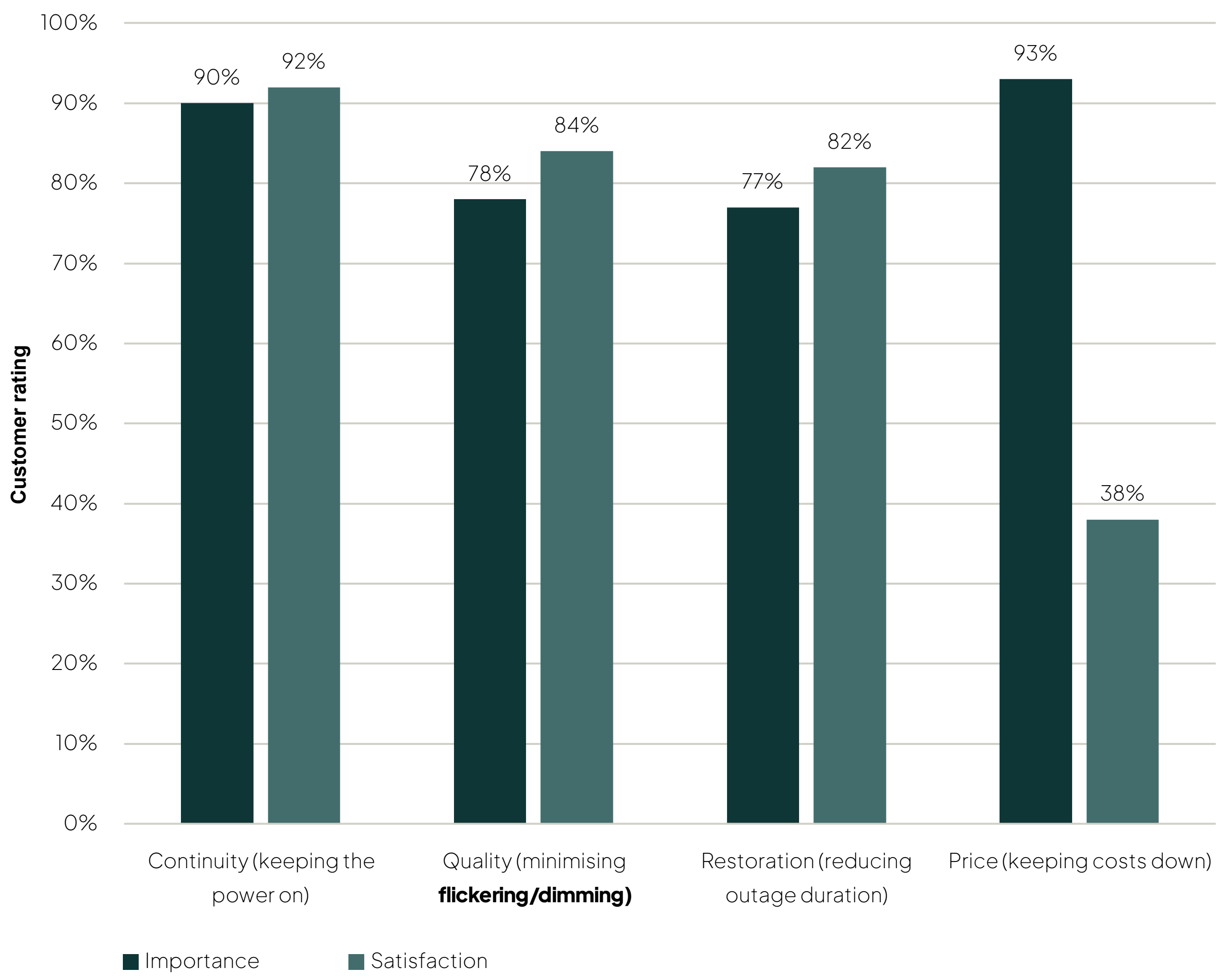
Hanmer Springs

1.2
What you have told us matters most

Through our extensive engagement programme, clear priorities have emerged. Understanding these priorities has directly shaped where we invest and how we plan.

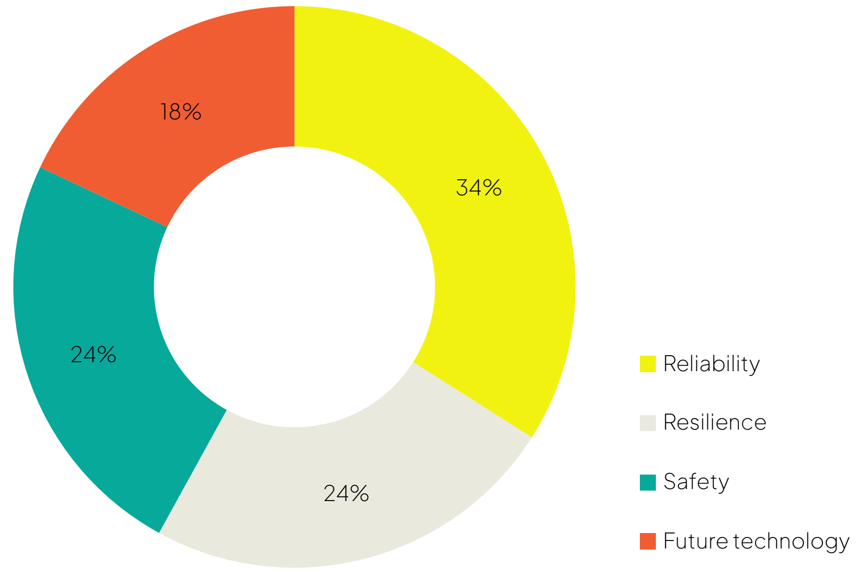
1.2.1 Customer priorities: the clear message

Our FY25 customer research involving almost 1,000 customers across North Canterbury shows strong and consistent priorities. As illustrated in Figures 1.2 and 1.3, reliability/continuity of supply is key to all customers.



Note *Based on FY25 Customer Engagement Survey, n = 1,925 respondents*

Figure 1.2 Customer ratings: importance vs satisfaction (four key service areas)



Note *Based on FY25 Customer Engagement Survey, n = 1,925 respondents*

Figure 1.3 Customers' investment priority allocation

Key insights from what you told us

Reliability remains paramount: Nine in ten customers (90%) rate continuity of supply as important, and satisfaction is strong at 92%. Reliability is your clear top investment priority, with 34% of your preferred investment allocation directed here. You expect power to be available when you need it, and interruptions to be minimised and resolved quickly.

Price satisfaction is the challenge: While 93% of customers rate keeping costs down as important, only 38% are satisfied with current pricing. This 55 percentage point gap between importance and satisfaction shows the tension between service quality and affordability. You want reliable power, but rising costs are a real concern.

Resilience against extreme weather matters: You allocated 24% of preferred investment to resilience, recognising that our network must withstand severe weather events. This reflects your direct experience with storm-related outages and concern about increasing weather severity.

Safety is non-negotiable: Safety also received 24% of investment allocation, nearly equal to resilience. You expect us to work safely, maintain equipment to prevent hazards, and communicate proactively about safety risks.

Future technology support, but not at any cost: While 37% of customers show interest in solar panels and 36% in solar storage, the majority (81%) are not willing to pay significantly more to support new technology adoption. You allocated 18% to future technology investment – important, but lower priority than reliability, resilience, and safety.

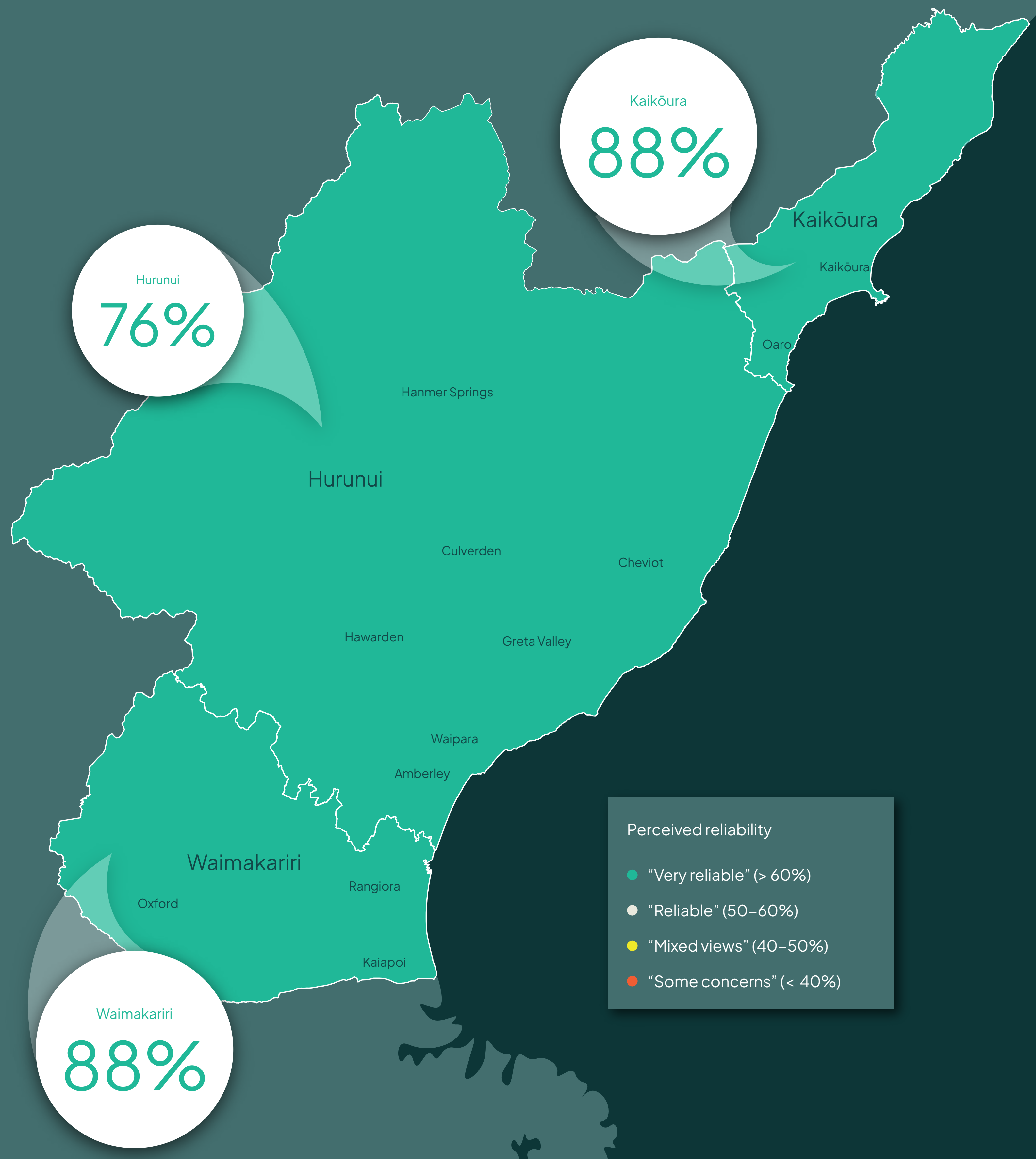


Figure 1.4 *Percentage of residents who rate their power as reliable or very reliable*

1.2.2 Regional differences in experience

While priorities are consistent across North Canterbury, customer experience varies by location. Understanding these differences helps us target investment where it is needed most.

Regional reliability perceptions: Overall, 86% of customers rate their power supply as reliable or very reliable (57% very reliable, 29% reliable). However, regional differences exist, as illustrated in Figure 1.4:

- Waimakariri and Kaikōura residents: 88% rate supply as reliable
- Hurunui residents: 76% rate supply as reliable

This reflects the challenges of serving dispersed rural communities where weather events have greater impact on longer rural feeders.

What this tells us

Urban customers generally experience higher reliability due to mesh network configuration and proximity to zone substations. Rural customers, particularly those on long rural feeders, experience slightly longer outage durations and more weather-related interruptions. Our investment plan reflects this by targeting rural feeder improvements while maintaining urban network performance (see section 4 for specific programmes).

1.2.3 Your satisfaction with our service

Beyond network reliability, customers interact with us for connections, faults, and general enquiries. We measure satisfaction at these touchpoints through our AMP Customer Service Survey. The results are shown in Table 1.2.

Table 1.2 FY25 AMP Customer Service Survey results (score out of 10)

Service aspect	FY25 actual	FY25 target	Status
Staff friendliness	7.2	> 7	Meets target
Communication	6.7	> 7	Below target
Engagement effort	6.4	> 7	Below target
Timeliness of service	6.4	> 7	Below target
Website application experience	5.5	> 5	Meets target
Quality of work	4.8	> 7	Below target
Overall satisfaction	6.9	> 7	Below target

Coldstream

What we have learned and how we are responding

We recognise we have set ourselves stretch targets to align with our strategic pillar of being a customer-focused organisation. In FY25 we have seen improvements compared to results in previous years and expect this to continue trending upwards with the customer service improvement initiatives and projects underway and planned.

Staff friendliness website application experience: These service aspects scored well in FY25, meeting our target and reflecting our team's professionalism and commitment to customer service. We maintain these standards through ongoing training and clear service expectations and ongoing website development with a priority around user experience.

Areas requiring improvement: Communication (6.7), engagement effort (6.4), timeliness (6.4), and quality of work (4.8) all scored below our target, including overall satisfaction (6.9). High demand for connections and service work in recent years created pressure on response times and service quality.

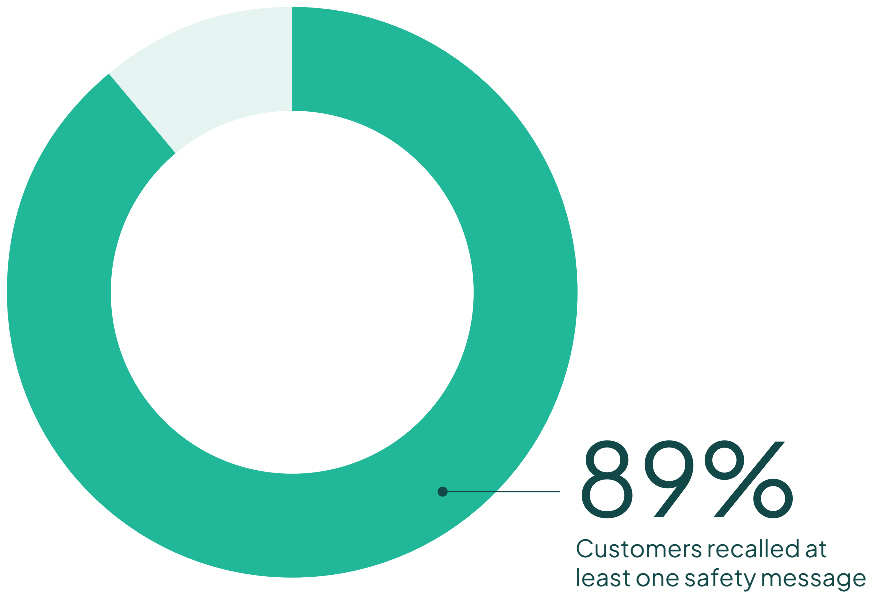
We are addressing this by:

- resourcing the delivery teams appropriately
- implementing service level agreements defining response timeframes
- upgrading systems to enable better customer communication and project tracking
- process mapping all customer-initiated work processes to identify and eliminate inefficiencies
- developing online tools for application submission and project tracking.

These improvements are expected to lift scores to target levels by FY27 as new processes and resources become fully embedded.

1.2.4 Safety awareness: our shared responsibility

Public safety around electricity infrastructure requires community awareness and participation. We invest in safety messaging campaigns each year and measure their effectiveness.



Campaign effectiveness

Approximately 89% of customers in FY25 recalled at least one safety message, consistent with previous years. Storm preparation messages achieve highest recall (55%), reflecting seasonal relevance and the community's experience with weather events. Tree-related messages also achieve strong recall (55%), contributing to vegetation management effectiveness. Figure 1.5 shows all the safety messages recalled.

Why this matters

Safety message recall correlates with reduced vegetation-related outages and improved emergency preparedness. When customers proactively manage trees on their property and prepare for storms, the whole community benefits through fewer interruptions and faster recovery.

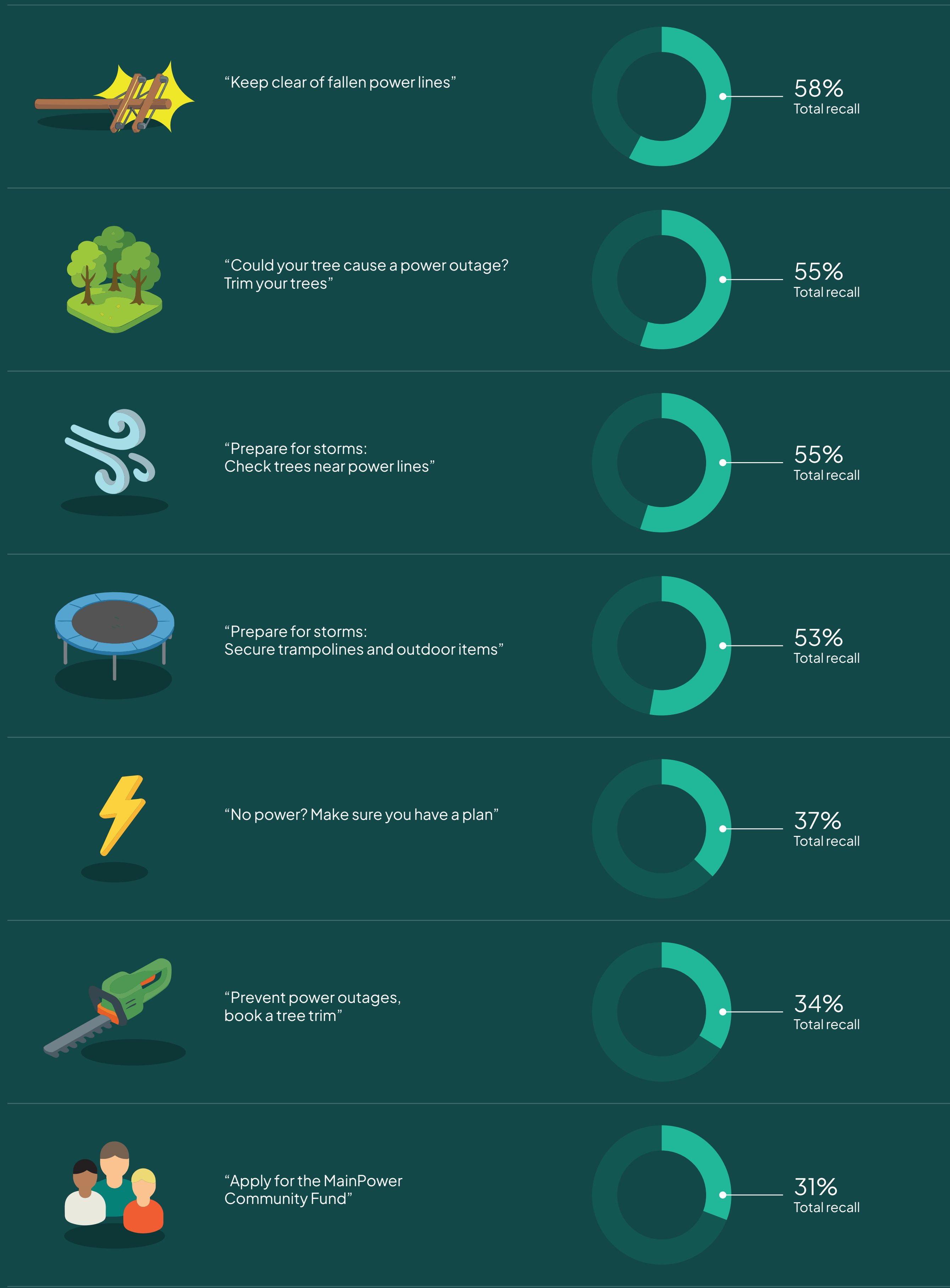


Figure 1.5 Percentage of customers who recalled specific messages around safety

1.3 Understanding our network performance

This section shows you how the network has been performing against the standards we set. We report our performance transparently, explain what drives results, and identify where we are working to improve.

1.3.1 Reliability: keeping your lights on

Network reliability is measured using two industry-standard measures that track how often and how long customers experience power interruptions:

SAIDI

(System Average Interruption Duration Index)

The average number of minutes per year that a customer is without power. Lower is better.

SAIFI

(System Average Interruption Frequency Index)

The average number of interruptions per year that a customer experiences. Lower is better.

These measures include both planned interruptions (when we take the power off deliberately for maintenance or construction) and unplanned interruptions (when faults occur unexpectedly). We calculate SAIDI and SAIFI using the definitions set out in the Commerce Commission regulatory document titled the *Electricity Distribution Information Disclosure Determination*, and we normalise the data as set out in the Commerce Commission paper titled *Default Price-quality Path Reasons Paper*, to filter the impact of significant events that exceed a threshold and are classified as major events.

We have adopted network performance measures that are set to shadow the default price-quality path (DPP) determination for non-exempt electricity distribution businesses (EDBs). We aim to keep our SAIDI and SAIFI below the shadowed upper-level targets calculated under the DPP, and, as shown in Figure 1.6, our network performed significantly better than target in FY25. In prior years, our SAIDI performance has been better than the upper-level SAIDI target, while SAIFI has been above the target in four of the years due to the number of unplanned interruptions to the network in this period.

Figure 1.6 Five-year normalised SAIFI and SAIDI performance (FY21–FY25)

What the numbers tell us

Normalised performance: The FY25 normalised SAIDI of 236 minutes was significantly better than our target of 381.8 minutes, demonstrating strong underlying network performance.

Table 1.3 breaks down the network performance into planned and unplanned SAIDI and SAIFI and shows how we have performed relative to our upper-level targets. Unplanned interruption performance was significantly better than target, largely attributable to the absence of adverse weather events, which typically affect our long, exposed, overhead distribution network. Planned interruption performance was better than target for both SAIDI and SAIFI, reflecting good adherence to plan in terms of average outage duration and average number of outages.

Table 1.3 FY25 planned and unplanned SAIDI and SAIFI, actual vs upper-level target

	FY25			
	SAIDI actual	SAIDI target	SAIFI actual	SAIFI target
Class B – planned outages	151.9	177.5	0.44	0.64
Class C – unplanned outages	84.6	204.3	1.03	1.25
Total	**236.5**	**381.8**	**1.47**	**1.89**

We know that not all power outages are the same, and understanding what causes them helps us deliver a more reliable service. By looking closely at all the outages over the past few years, we gain insight into why interruptions happen. Figures 1.7 to 1.9 show network-wide average interruption durations and average interruption frequency by cause, before any adjustments for extreme events. These charts highlight that the largest cause of interruptions has been severe weather, with the extreme events in FY24 making a notable impact.

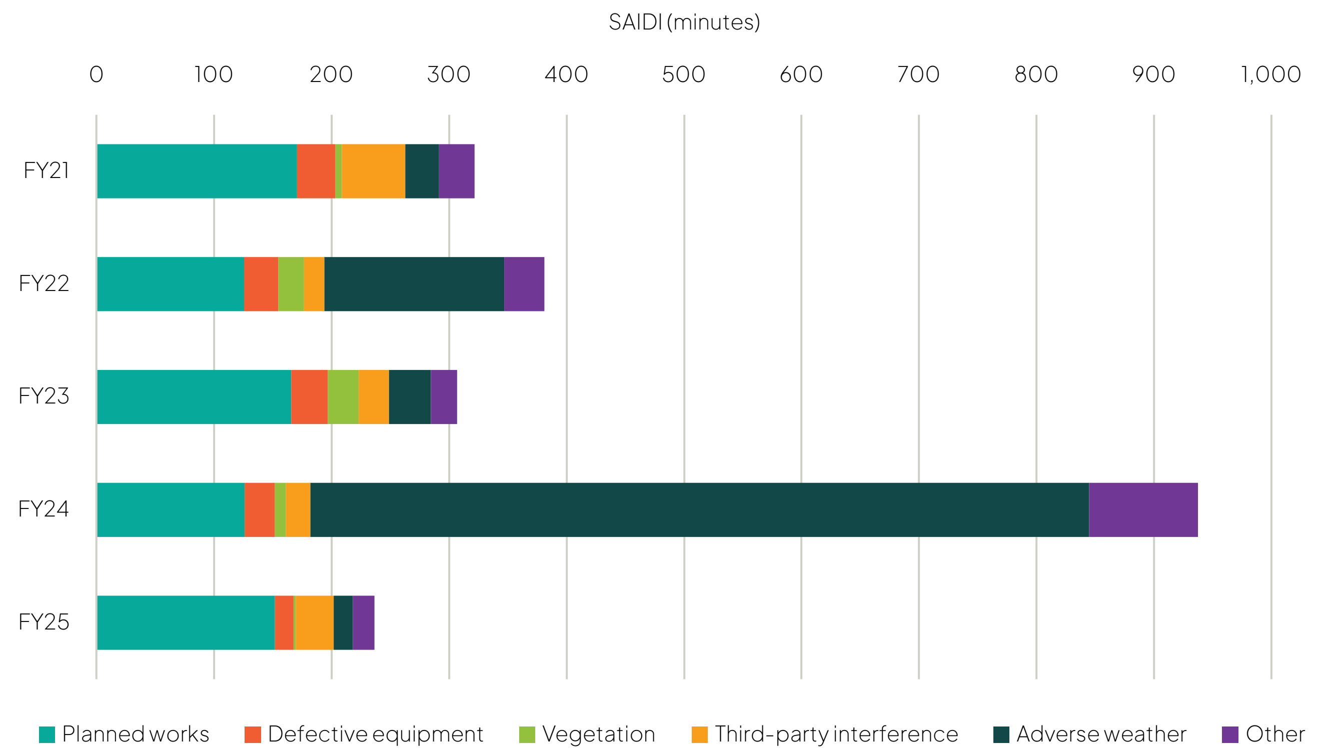


Figure 1.7 Absolute SAIDI by cause (FY21–FY25)

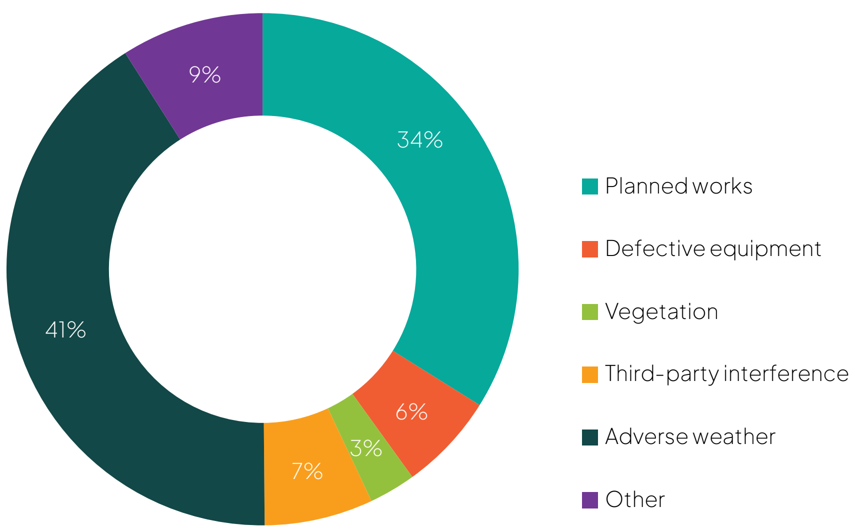


Figure 1.8 SAIDI by cause as a percentage

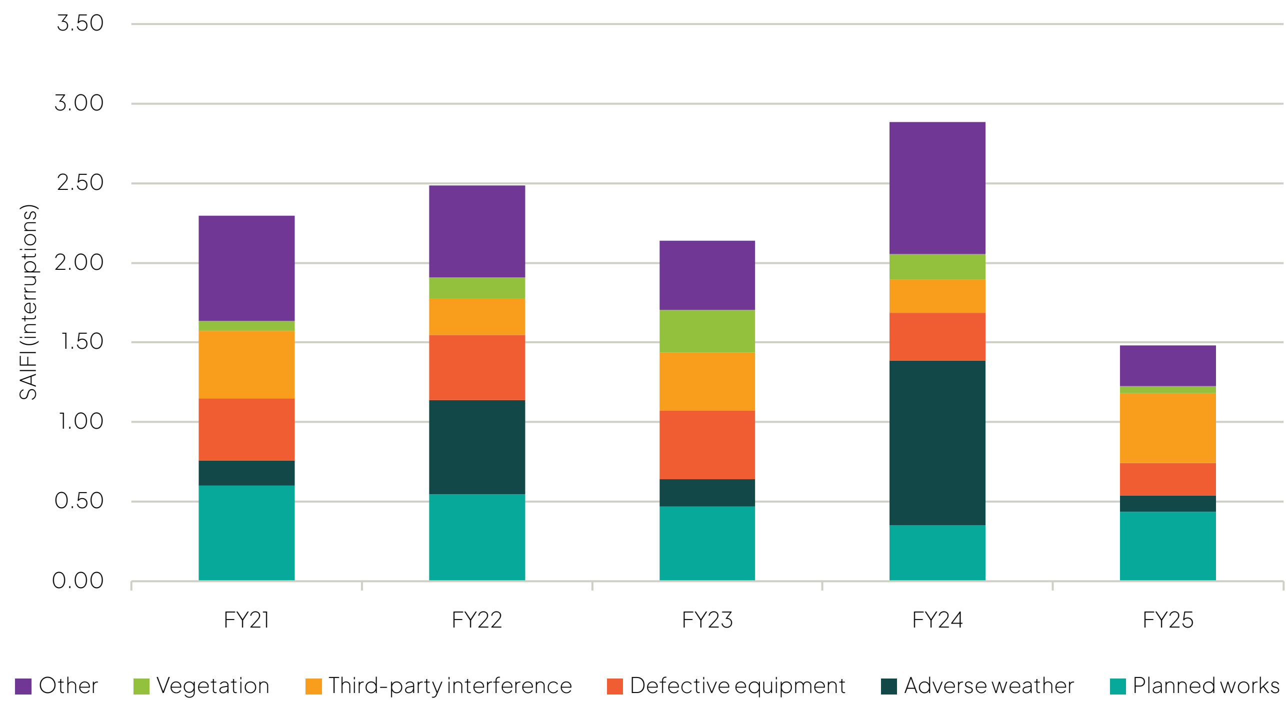


Figure 1.9 SAIFI by cause (FY21–FY25)

What this tells us about our reliability

Planned works (FY25: 64% of SAIDI, 27% of SAIFI): A significant portion of interruptions in FY25 were due to planned maintenance and renewal work. While these interruptions are scheduled and communicated in advance, they still affect customers. Our approach:

- minimise planned work duration through efficient work practices
- combine multiple tasks in single outages where possible
- schedule work during low-demand periods (overnight, weekends) where feasible
- provide advance notice (minimum 48 hours).

Defective equipment: Equipment failures drive unplanned interruptions. This reinforces the importance of our asset renewal programme (see section 3), which targets ageing equipment before it fails in service.

Vegetation: Trees and vegetation contacting lines cause outages. Our vegetation management programme (see section 3.7) maintains clearances to regulatory standards. Customer participation in tree management on private property (prompted by our safety campaigns) is also critical.

Third-party interference: Vehicle damage, overhead contact, and vandalism affect the network. We work with councils on corridor protection and promote "Dial Before You Dig" to contractors.

Weather and environment: Extreme weather remains an ongoing challenge. Our network resilience strategy focuses on:

- overhead line construction standards (stronger poles, wider spans)
- developing a model to identify environmental risk and vulnerability that supports asset stress testing and scenario planning
- vegetation management in exposed corridors
- rapid response and restoration capability.

1.3.2 Planned vs unplanned performance of our network

It is useful to separate planned interruptions (which we control) from unplanned interruptions (which are typically weather or fault-driven). Planned SAIDI has remained relatively consistent over the five-year period, while unplanned SAIDI has varied in response to the number and duration of network interruptions. As shown in Figure 1.10, FY22 and FY24 SAIDI was elevated even though the major weather events in those years were normalised.

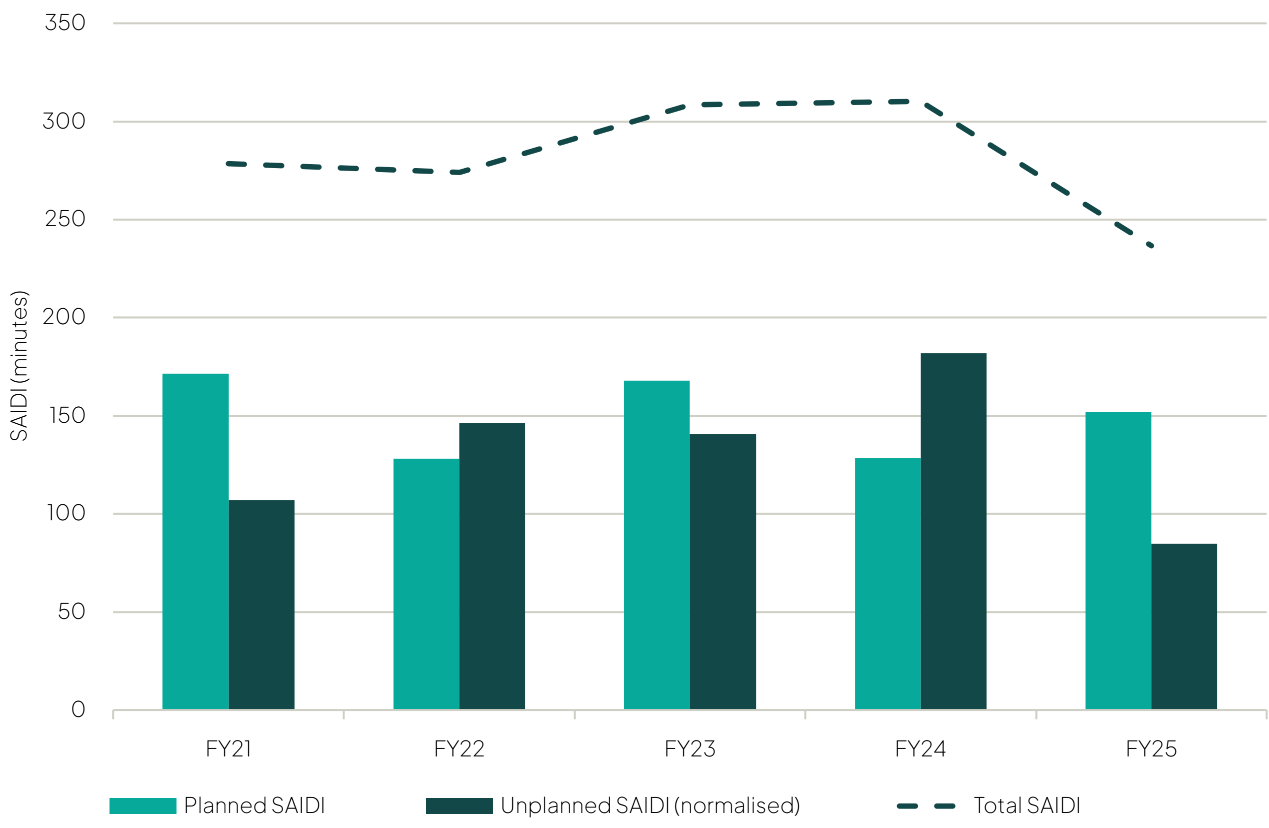


Figure 1.10 Planned vs unplanned SAIDI (FY21–FY25)

Performance trends

Planned outages – stable trend

We have successfully managed planned outage duration over the past five years through:

- better work planning and sequencing
- live-line working techniques where appropriate
- improved crew productivity.

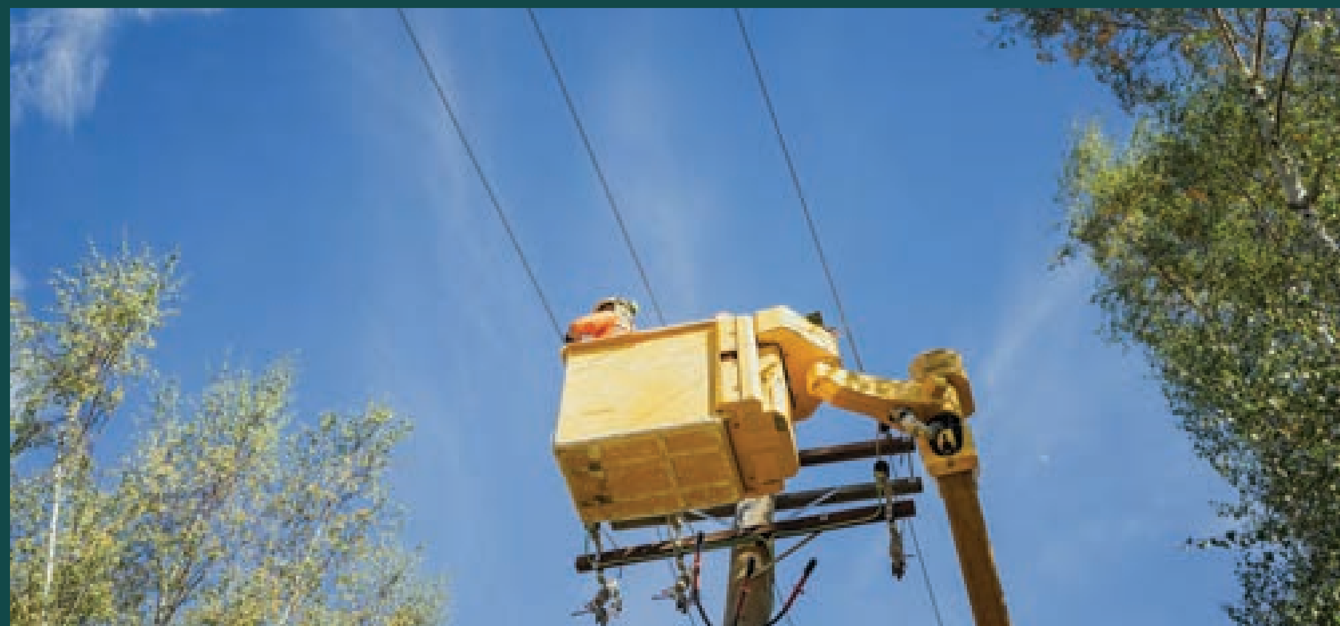
In four of the five years FY21–FY25, actual planned outage performance was better than forecast.

Unplanned outages – gradual improvement

Excluding major weather events, we have seen a gradual reduction of interruptions related to defective equipment, but an upward trend in unplanned outages related to third-party interference. This reflects:

- the effectiveness of our asset management and renewals programme
- increased customer connections and network utilisation (higher load).

This trend reinforces the need for sustained investment in asset renewal and network resilience, which is central to our 10-year plan.



1.3.3 Restoration performance: getting your power back

When unplanned outages occur, restoration speed matters. We have introduced a new performance measure tracking how quickly we restore power after faults.

3 hours

Unplanned interruptions restored within 3 hours

Our target is to restore power to 80% of unplanned interruptions within 3 hours from when the outage began.

80%

FY25 performance

80% of unplanned interruptions were restored within 3 hours (target: 80%).

This measure captures our emergency response capability and crew productivity.

Factors affecting restoration time include:

- time to identify fault location (dispatch, travel, patrol)
- fault complexity (single fault vs multiple damage points)
- equipment and materials availability
- weather conditions (safe working limits)
- access to fault site (remote rural locations).
- We are improving restoration times through:
- enhanced fault location technology (indicators, sensors)
- strategic equipment stockpiles at depots
- 24/7 response capability with contractor support
- crew training and emergency response drills.

1.3.4 Voltage quality and low-voltage network monitoring

Reliability is not just about keeping the power on. It is also about maintaining consistent voltage quality. Too-high or too-low voltage can damage appliances and equipment.

How we monitor voltage quality:

- Transformer monitors across the network measure low-voltage bus voltages and end-of-line voltages.
- Smart meter analytics provide visibility of voltage at individual customer connections.
- Customer complaint investigations identify localised issues.

Low-voltage monitoring programme: We are enhancing our low-voltage network monitoring capability using smart meter data. Product and data acquisition trials have been running through FY25 and will inform our longer-term low-voltage strategy. This is particularly important as:

- customer-owned solar generation increases (voltage rises on low-voltage networks)
- electric vehicle (EV) charging grows (potential voltage drop issues)
- heat pumps and heat pump water heaters proliferate (load increase).

Constraint information sharing: We share information about current and forecast network constraints with potential new customers. This helps customers and developers understand network capability before making connection applications.

We provide:

- high-level zone substation capacity information (available on request)
- known constraint areas where connection may require network upgrade
- estimated upgrade costs for constrained areas
- forecast constraint areas based on growth projections.

See section 1.6.2 for details on how we share this information during the connection process.

1.3.5 Safety and environmental performance: our culture of safety

Public and worker safety is paramount. We set a target of zero injuries to the public and no harm requiring medical attention to workers. Table 1.4 illustrates the number and types of incidents we experienced this year.

Table 1.4 Safety and environmental performance

Safety measure	FY24 actual	FY25 actual	FY26 target
Lost-time injuries	0	4	0
Medical-treated injuries	2	1	0
Injuries to members of the public	0	0	0
Uncontained oil spills	0	0	0
Sulphur hexafluoride (SF_6) gas lost (% of total gas volume)	0.28%	0.16%	< 1%

Our safety performance

We are proud of our ongoing commitment to safety, and while there have been some injuries to our staff in recent years, we remain focused on continually improving our safety processes. This positive safety culture motivates us to uphold high standards and work proactively to keep everyone as safe as possible.

Our safety performance is driven by:

- comprehensive safety management systems
- regular training and competency assessment for staff and contractors
- hazard identification and risk assessment processes
- a safety-focussed maintenance programme
- public safety campaigns and education
- incident investigation and lesson-learning.

We report all employee injury and public safety events through our Tohu safety information management system. We are also process-mapping critical processes and identifying critical controls to maintain safety standards.

Environmental performance

We aim to minimise the environmental impact of our operations, particularly regarding oil and gas losses from network equipment.

Oil spills

Transformers and other oil-filled equipment can potentially leak if damaged or if seals fail. We maintain a zero uncontained oil spills target, achieved through:

- regular equipment inspections identifying leaks early
- spill containment procedures and equipment
- rapid response to equipment damage
- retirement of ageing oil-filled equipment.

Sulphur hexafluoride (SF_6) gas

Some switchgear uses SF_6 gas as an insulating medium. SF_6 is a potent greenhouse gas, so we aim to minimise losses through:

- gas-tight equipment specifications
- regular gas pressure monitoring
- leak detection and repair procedures
- recording and reporting gas losses
- consideration of SF_6-free alternatives in new equipment.

In recent years, we have had only minor leaks (0.16%) of SF_6 gas – well below our 1% target – and no uncontained oil spills. This result reflects our strong commitment to protecting the environment. However, we recognise that keeping our standards high requires ongoing effort and attention. We remain dedicated to maintaining this level of care, ensuring our operations are safe for both people and the environment.

1.4
Our service commitment to you

This section sets out the service levels we commit to delivering over the next 10 years. These targets reflect what you have told us you expect, balanced with what is achievable at reasonable cost.

1.4.1 Our performance framework

We measure our performance across six key areas that matter to customers and stakeholders:

Reliability
Keeping your power on

Safety
Protecting workers, public, and environment

Customer satisfaction
Responsive, high-quality service

Delivery
Completing planned work programmes

Capability
Maintaining and improving our systems and processes

Value for money
Benchmarking against industry peers

Table 1.5 shows all our performance indicators and targets for the 10-year planning period.

Table 1.5 Performance targets

			Past performance targets		Future performance targets
Service class	**Performance indicator**	**Performance measure**	**FY25**	**FY26**	**FY27–FY36 targets**
Reliability – DPP aligned	SAIDI	Average minutes of supply lost per customer per year	236.5	381.8	371.8
	SAIFI	Average number of times a customer's supply is interrupted per annum	1.48	1.89	1.83
	Unplanned interruptions restored within 3 hours	% of unplanned interruptions where the last customer's supply was restored in less than 3 hours	80%	80%	80%
Reliability – Self-imposed targets	Self-imposed SAIDI target	Average minutes of supply lost per customer per year	236.5	381.8	290.9
Health, safety, environment, and quality	Safety of workers	No injuries requiring medical attention	None	None	None
	Safety of public	No injuries to members of the public	None	None	None
	SF_6 gas lost	Gas lost as % of total gas volume	< 1%	< 1%	< 1%
	Oil spills	Uncontained oil spills	None	None	None
Customer satisfaction	Engagement effort	Score out of 10	> 7	> 7	> 7
	Staff friendliness	Score out of 10	> 7	> 7	> 7
	Quality of work	Score out of 10	> 7	> 7	> 7
	Timeliness of service	Score out of 10	> 7	> 7	> 7
	Communication	Score out of 10	> 7	> 7	> 7
Delivery	Maintenance delivery	Maintenance programme delivery by budget	86%	> 90%	> 90%
	Capital delivery	Capital programme delivered by budget	90%	> 90%	> 90%
Capability	Asset Management Maturity (new measure)	Complete AMMAT workstreams	–	> 90%	> 90%
Value for money	Industry benchmarking	Position against peer group for OPEX, CAPEX, SAIDI, SAIFI	< 75th percentile	< 75th percentile	< 75th percentile

Notes

The increase in SAIDI and SAIFI targets from previous years' targets is due to a change in the measurement of quality standards to shadow the DPP determination for non-exempt EDBs.

Customer satisfaction scores use a scale of 1–10, where scores above 7.0 indicate good performance.

Asset Management Maturity is assessed using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

OPEX = operating expenditure; CAPEX = capital expenditure

1.4.2 Material changes in service level targets

The SAIDI and SAIFI targets shown in Table 1.5 represent a change from previous AMPs. The new targets shadow the DPP determination.

Why have the targets changed?

The Commerce Commission conducted a comprehensive review of quality standards for EDBs as part of the 2020–2025 electricity default price-quality path reset (DPP4). This review:

- analysed historical performance of all EDBs
- assessed the relationship between expenditure and reliability
- set quality standards that reflect achievable performance for each EDB's network characteristics
- balanced reliability improvement with cost pressures on customers.

For us, the new targets of 381.8 SAIDI minutes and 1.89 SAIFI interruptions reflect:

- our network architecture (mix of urban mesh and rural spur feeders)
- historical performance variability (particularly weather impacts)
- industry benchmarking against comparable EDBs
- assessment of cost-effective reliability improvement options.

What does this mean for customers?

The new targets do not represent a reduction in service quality. Rather, they:

- acknowledge the reality of operating a network exposed to weather events
- set realistic performance levels that can be maintained without excessive cost
- focus investment on areas where reliability can be improved cost-effectively
- allow for performance variation year-to-year while maintaining an acceptable long-term average.

Our commitment remains unchanged – to deliver reliable electricity supply that meets customer expectations while maintaining affordability.

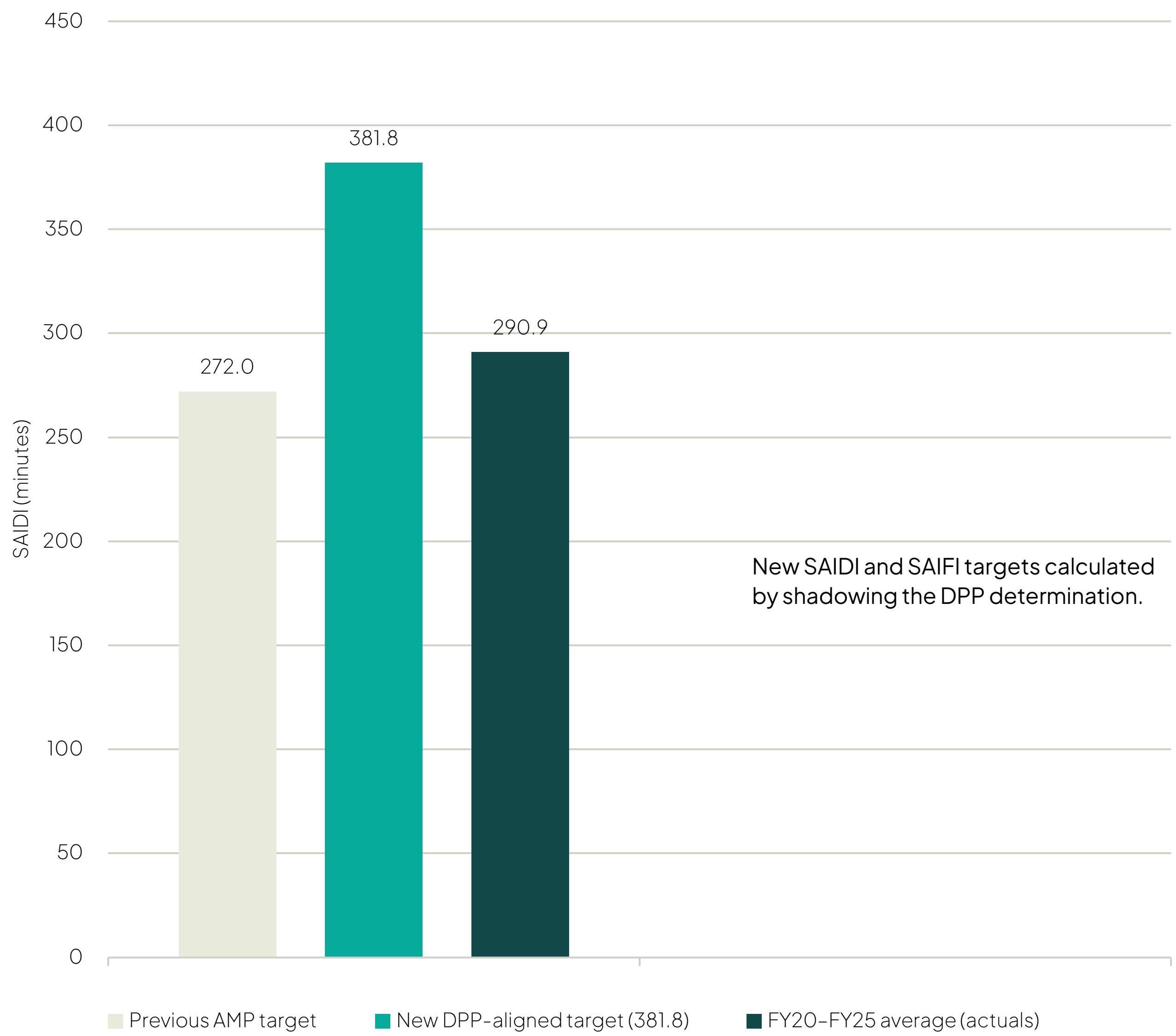


Figure 1.11 New SAIDI targets vs historical performance

As outlined in Figure 1.6, historical performance shows we typically operate close to SAIDI and SAIFI targets under normal conditions (FY25 SAIDI was 236.5 minutes, well below the 381.8 target).

1.4.3 How we set and review performance targets

Our performance targets are not arbitrary. Figure 1.12 outlines the structured process we take to ensure we consistently achieve our targets.

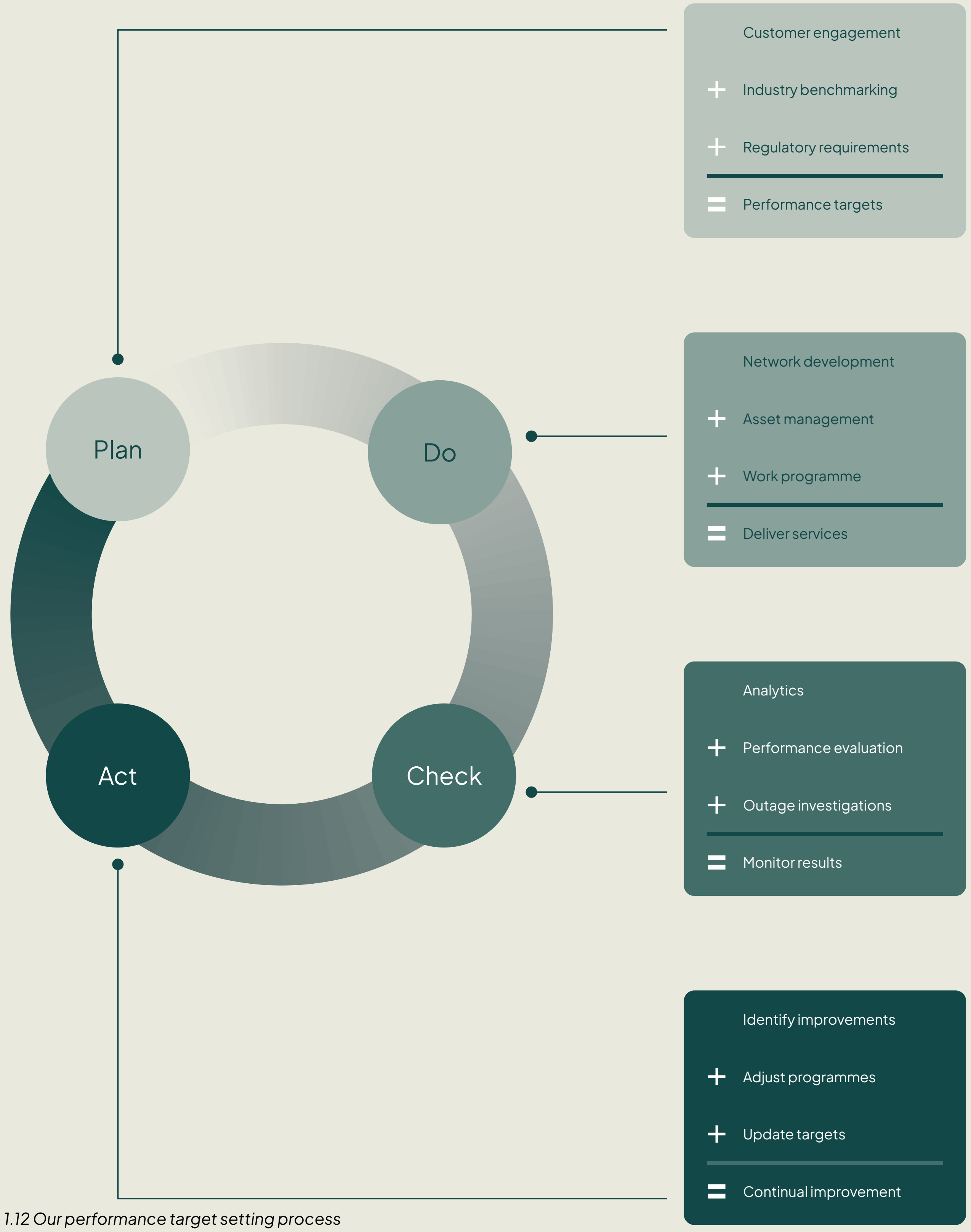


Figure 1.12 Our performance target setting process

Inputs to target setting

- **Customer expectations:** What you have told us through surveys and engagement about acceptable service levels
- **Industry benchmarking:** How we compare to similar EDBs across New Zealand
- **Regulatory requirements:** Commerce Commission quality standards and reporting obligations
- **Technical analysis:** Historical trends, feeder reliability data, root cause analysis
- **Cost–benefit assessment:** What level of investment is justified to achieve different service levels

Continual improvement cycle

We review performance through:

- monthly operational reporting of SAIDI, SAIFI, safety, and project delivery
- quarterly Board reporting and governance review
- annual performance evaluation against targets (documented in this AMP)
- industry benchmarking against peer group EDBs
- customer satisfaction tracking at service touchpoints
- detailed outage investigations for significant events.

When performance falls short of target, we:

- investigate root causes (equipment, process, external factors)
- identify corrective actions (asset renewal, procedure changes, training)
- adjust work programmes to address underlying issues
- track improvement initiatives to closure.

When performance exceeds target, we:

- understand what enabled good performance (practices to replicate)
- assess whether targets remain appropriate or should be tightened
- share lessons learned across the organisation and with industry.

1.4.4 Monitoring individual feeder reliability

While network-wide SAIDI and SAIFI measures overall performance, some parts of the network perform better than others. We monitor reliability at the individual feeder level to identify targeted improvement opportunities.

Feeder reliability classification: We classify feeders based on reliability performance and customer density:

- **Urban:** Feeders serving concentrated customer areas are typically interconnected so that we can supply power from various directions to provide flexibility and improve reliability
- **Medium town:** Feeders serving our medium towns are typically interconnected, but may not allow for as much supply flexibility as our urban feeders
- **Rural mesh town:** Feeders serving the larger rural towns with network interconnection
- **Rural mesh:** Rural feeders with network interconnection
- **Rural spur town:** Radial feeders serving dispersed rural towns with no network interconnection
- **Rural spur:** Radial feeders serving dispersed rural customers with no network interconnection

Each feeder type has different expected performance. Our urban customers typically experience fewer and shorter outages than rural customers due to network configuration. Figure 1.13 illustrates our network segmentation, Figure 1.14 shows the average interruption duration for each network segment, and Table 1.7 shows the percentage of connection points to each feeder type from across our network.

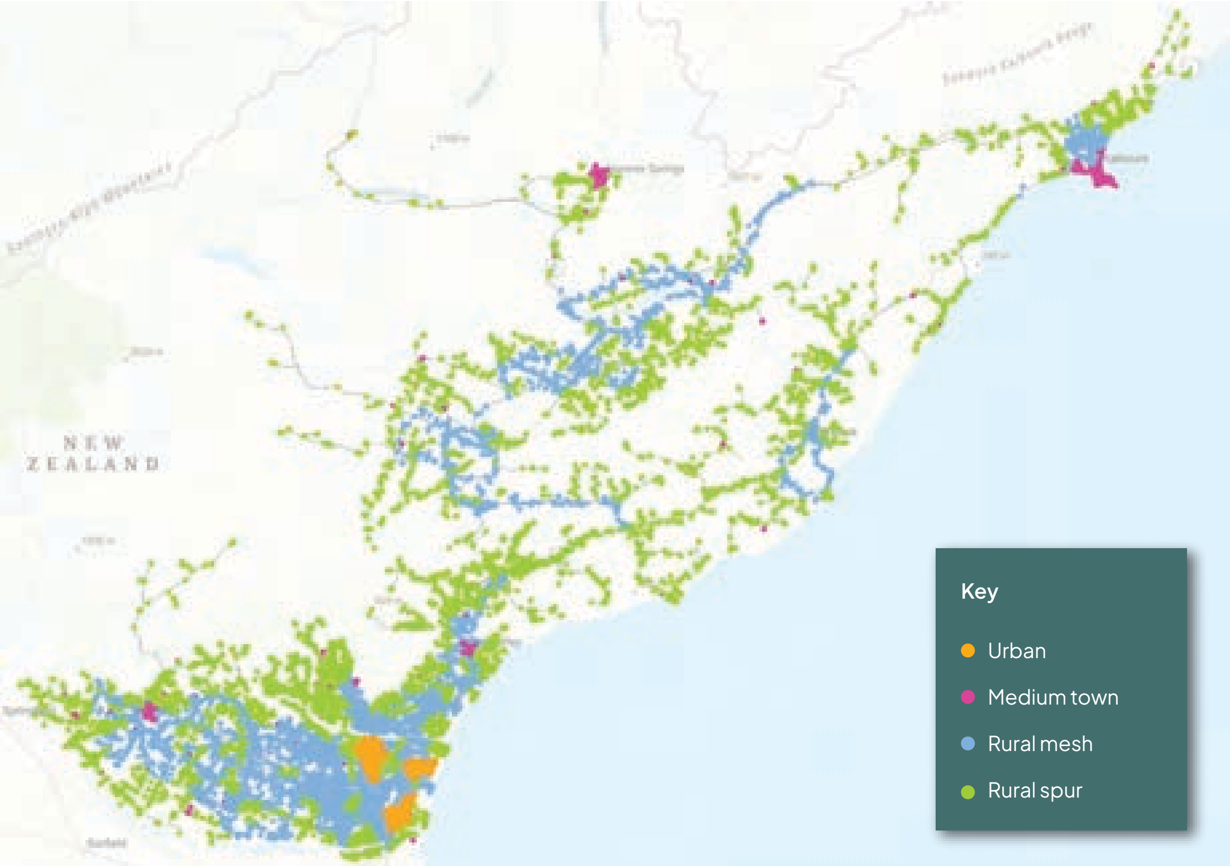


Figure 1.13 Network segmentation into urban, medium town, rural mesh, and rural spur

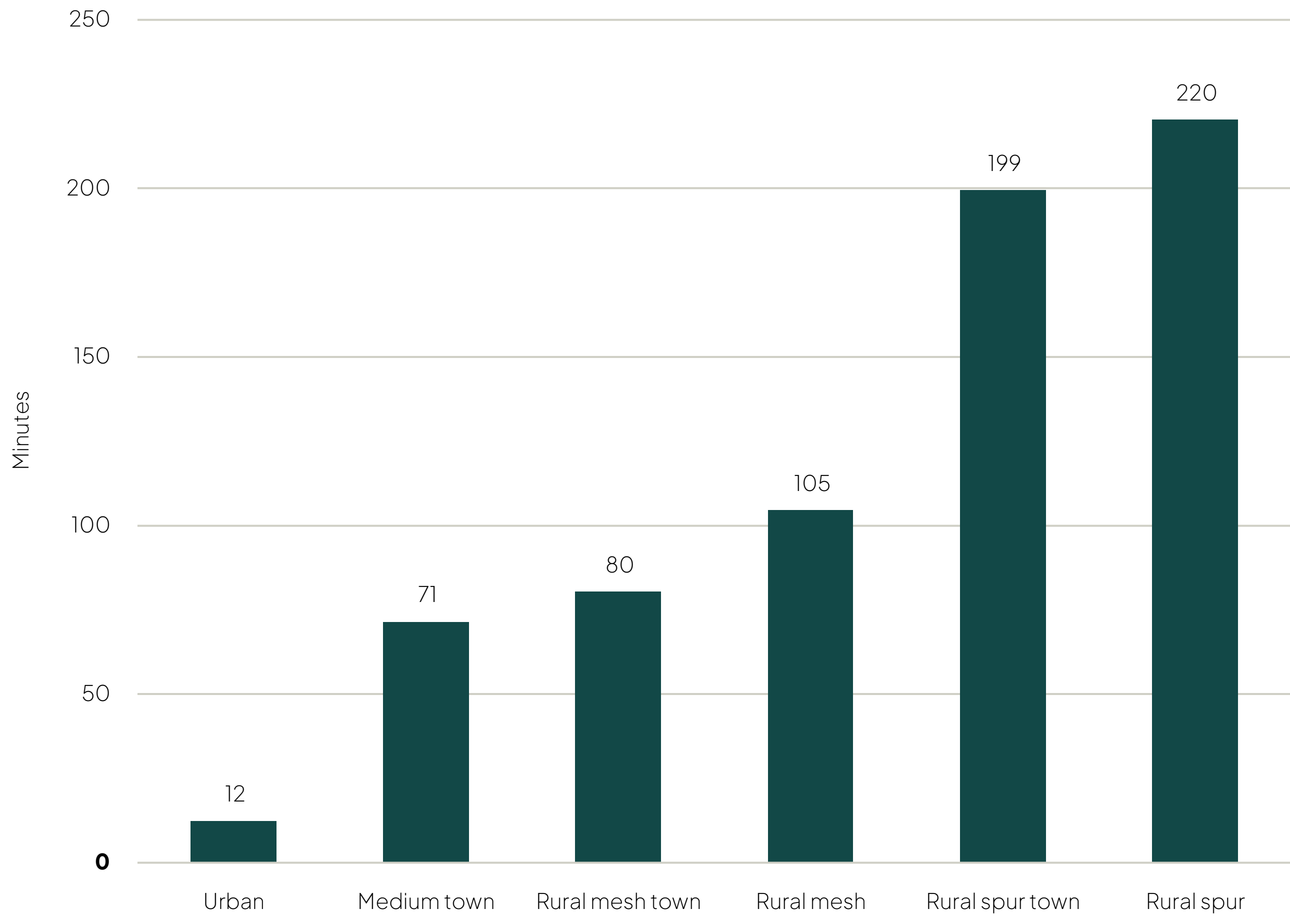


Figure 1.14 Average outage duration in FY25, by network segment

Table 1.6 Customer distribution by classification

Customer classification	% of ICPs*	FY25 SAIDI (minutes)
Urban	42%	5.3
Medium town	13%	9.4
Rural mesh town	4%	3.5
Rural mesh	20%	21.3
Rural spur town	3%	6.6
Rural spur	17%	38.4

** ICPs = installation control points*

This granular analysis enables us to:

- set realistic expectations for customers in different areas
- assist in ranking reliability improvement projects
- analyse the performance of the network by configuration.

Section 4 details specific reliability improvement programmes.

1.5 Performance improvement initiatives

Understanding performance is one thing; improving it is another. This section explains the initiatives we are undertaking to deliver better outcomes for customers.

1.5.1 Network reliability improvements

Targeted feeder renewal programme

Based on our feeder reliability analysis, we have identified specific feeders requiring asset renewal or reinforcement. The programme focuses on:

- replacement of ageing overhead conductors and poles
- installation of additional protection devices (reclosers, sectionalisers)
- vegetation management in high-risk corridors
- strategic network reconfiguration to reduce fault impact.

Expected outcome

Reduction in feeder SAIDI and SAIFI

(See section 5 for detailed asset-specific programmes)

Rapid restoration capability

We are enhancing our ability to restore power quickly after faults through:

- additional fault indicators to support fault location
- strategic materials stockpiles at regional depots
- enhanced 24/7 contractor response arrangements
- live-line working training and equipment
- improved emergency response procedures and coordination.

Expected outcome

Increase percentage of faults restored within 3 hours to > 80%

Network resilience to weather events

Recognising that extreme weather events have a major impact on the network, we are investing in:

- network design improvements in exposed areas
- enhanced vegetation management in weather-prone corridors
- rapid damage assessment capability (drones, mobile mapping).

Expected outcome

Reduced impact of weather events on network-wide SAIDI

1.5.2 Customer service improvements

Service Delivery Team enhancements

Based on customer feedback about timeliness and communication, we have:

- increased resourcing in the Service Delivery Team
- restructured workflows to reduce bottlenecks
- implemented service-level agreements defining response timeframes
- upgraded systems to enable better project tracking and customer communication.

Expected outcome

Customer satisfaction scores for timeliness and communication > 7.0 by FY26

Connection process improvements

We are streamlining the connection process (detailed in section 1.6.2) through:

- clearer upfront information about requirements and timeframes
- process mapping to eliminate unnecessary steps
- online tools for application submission and project tracking (in development).

Expected outcome

Reduced connection timeframes, higher customer satisfaction with connection experience

Outage communication

We have enhanced communication during outages through:

- automated SMS alerts when outages occur and when power is restored
- an interactive online outage map showing affected areas and estimated restoration time
- proactive communication for planned outages (minimum 48 hours notice)
- direct communication with critical customers (medical dependencies, large commercial).

Expected outcome

Improved customer satisfaction with communication during outages

1.6
How we serve you: connections and customer service

This section explains the practical ways we interact with customers: connecting you to the network, managing distributed generation, and resolving any concerns you may have.

1.6.1 Notice of planned and unplanned interruptions

When we need to turn off power for maintenance, construction, or upgrades, we understand how important it is to keep our customers informed. For planned interruptions, we provide at least 48 hours advance notice in accordance with our Connection Agreement. We communicate through multiple channels depending on your preference – including SMS text message, email, or letter – and display all planned outages on an interactive map on our website. For customers with special needs or greater reliance on electricity, such as those with medical equipment or critical business operations, we provide direct communication via phone or email to ensure you have adequate time to prepare.

When unexpected faults occur, communication speed is critical. As soon as an unplanned outage is verified, we send an SMS text message advising customers of the interruption. We send a further SMS text message when power is restored, confirming the issue has been resolved. All outages, whether planned or unplanned, appear on our website outage map with real-time updates showing current outages, affected areas, estimated restoration times, cause of outage where determined, number of customers affected, and progress updates as work continues. For major events affecting large numbers of customers, we broaden our communication to include social media channels, radio broadcasts, and direct media communications for rapid message distribution.

Our online outage map (available at www.mainpower.co.nz) provides real-time information to help customers plan around disruptions and understand what is happening. The map shows where outages are occurring and gives customers visibility of our restoration efforts and expected timeframes. This transparency helps our customers make informed decisions about their activities during outages.

The process of getting connected typically follows eight key stages, each with specific activities and timeframes. Figure 1.15 shows this journey from the customer's perspective.

The connection journey

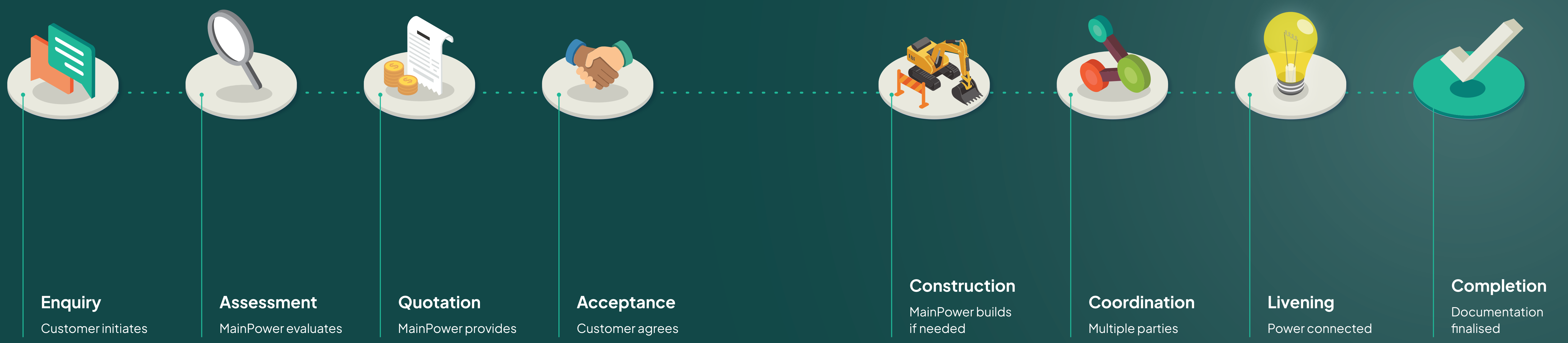


Figure 1.15 Connection process flowchart

The connection journey

Connection applications

Customers contact MainPower and provide us detailed information about their connection requirements.

Assessment and network capacity information

We assess applications by considering network capacity at the connection point, distance from existing infrastructure, known constraints, and compliance with safety standards. If capacity exists and infrastructure is nearby, we proceed directly to connection design. If not, we design necessary upgrades or extensions.

Before committing to property purchase or development, customers contact us for network capability information. We provide zone substation capacity details, identify constraint areas requiring upgrades, give indicative upgrade costs, and share forecast constraint areas. This early engagement helps customers make informed decisions and factor connection requirements into planning and budgeting.

Understanding your quotation

Our detailed quotation breaks down connection charges (standard schedule or bespoke pricing), network extension or upgrade costs if required, capital contributions if applicable, design and inspection fees, estimated completion timeframe, and validity period. If the customer queries any charges, we provide detailed explanation within 10 working days as required under information disclosure requirements.

For connections requiring significant network extension or upgrade, we may seek a capital contribution. Our Capital Contributions Methodology (available on our website) explains when contributions apply, our calculation methodology, refund provisions if others subsequently connect, and alternative arrangement options. We are currently reviewing this policy as part of the Electricity Authority's Network Connections Project.

From acceptance to power on

Once the quotation is accepted and the customer meets the requirements (signed acceptance, payment or payment arrangement, necessary consents, retailer confirmation), we begin network construction if needed. Simple connections to existing infrastructure may require minimal work. Significant extensions for subdivisions or remote properties may take weeks or months depending on scope, weather, ground conditions, materials availability, and contractor scheduling. We provide specific timeframe estimates in our quotation.

Final connection stages involve multiple parties: We provide the network connection point, the customer's energy retailer arranges the supply contract and coordinates metering, the metering equipment provider installs the meter, and a livening agent performs physical connection. We coordinate all parties, but customers can help by arranging their retailer early, ensuring their electrical installation is compliant, providing site access, and responding promptly to information requests.

Once the network is ready, metering is installed, and electrical inspection passes, the livening agent connects and energises the supply. Safety checks confirm correct operation, the retailer activates the account, and the customer has power. We complete final documentation: as-built records, national registry update with the installation control point (ICP) number, compliance filing, and final invoicing.

Connection timeframes and what affects them

Table 1.7 outlines some of the variables that can impact the time it takes to effect a new connection. The key consideration is ensuring that all the necessary infrastructure for the connection is in place before installation begins.

Table 1.7 Typical connection timeframes

Connection type	Minimum timeframe	Key assumptions	Variables that extend timeframe
Standard new connection	15 working days	• Network capacity available • Existing infrastructure in place • All parties coordinate effectively • No complications	• Retailer or metering equipment provider scheduling delays • Incomplete applications • Inspection failures • Peak demand periods
Network extension required	4–12 weeks	• Straightforward extension • No resource consents needed • Good weather and ground conditions • Materials readily available	• Extension length and complexity • Resource consent requirements • Weather delay • Materials supply constraints • Contractor availability
Small residential solar (< 10 kW)	10–25 working days	• Complete application • Network capacity available • Approved installer • Timely compliance documentation	• Application completeness • Technical assessment complexity • Installer compliance delays (up to 20 days after installation)
Larger distributed generation systems (> 10 kW)	4–8 weeks or more	• Complete technical specifications • Network impact assessment • Protection requirements identified • Approved installation	• Technical assessment complexity • Network impact studies required • Protection system upgrades needed • Multiple approval stages

The connection journey

Avoiding common connection delays

- **Network extension requirements** are often the longest delay factor. If the property is not close to existing infrastructure, construction can extend timeframes from weeks to months. Customers are encouraged to contact us early – before property purchase if possible – to understand extension requirements and factor them into planning.
- **Network capacity constraints** may require upstream upgrades before connection. Customers should ask about constraints at the enquiry stage, particularly for developments or large loads. Early engagement during planning identifies capacity issues when solutions are most flexible.
- **Multi-party coordination** involves MainPower, the retailer, the metering equipment provider, and contractors. Customers can minimise coordination delays by arranging their retailer early, ensuring electrical installation is compliant before requesting metering, providing site access, and responding promptly to requests.
- **Incomplete applications** cannot progress. Customers are encouraged to use our application checklist and provide site plans, load calculations, consent documentation, and technical specifications upfront. Quick responses to information requests prevent weeks of delay.
- **Distributed generation compliance documentation** is mandatory. Customers should use approved installers experienced with MainPower requirements who commit to providing documentation within 20 days of installation completion.
- **Resource availability** fluctuates with peak building season and emergency restoration work. Customers are encouraged to apply early and maintain timing flexibility where possible. We ask that customers understand that storm restoration takes priority over routine connections.

Minimising connection costs

We minimise costs through standardised designs for common connection types, bundling connection work with other network activity where possible, and competitive contractor procurement.

Where standard approaches prove costly, we discuss alternatives, including:

- specification reduction if lower capacity suffices
- staged connections providing initial lower capacity with future upgrade capability
- developer-funded extensions for subdivisions, or
- in remote areas, consideration of stand-alone power systems.

Transparent quotations break down all costs clearly. If charges are unclear, we explain in detail within 10 working days.

Distributed generation: solar, wind, and battery connections

Distributed generation equipment requires additional approvals because exported power affects voltage and protection systems, safety systems must isolate distributed generation during network maintenance to protect workers, network export capacity must be assessed, and connection configuration must meet technical and safety standards.

The process involves:

- application with technical details
- MainPower assessment of capacity and protection requirements (an Approval Notice is issued if safe to proceed)
- installation by an approved installer to compliance standards
- installer certification of compliant installation (mandatory)
- metering upgrade to enable import/export measurement
- final commissioning.

Timeframes follow national code requirements: small residential systems under 10 kW typically take 10–25 working days; larger systems may take 4–8 weeks or more as they require detailed technical assessment. Installer compliance documentation is due within 20 days of installation completion.

Occasionally, distributed generation is installed without proper approval, creating safety risks. We work constructively to correct missed paperwork. If serious safety concerns exist, temporary disconnection may be required until rectified. Customers can avoid issues by:

- using approved installers
- applying before purchasing equipment
- providing complete technical specifications
- ensuring the installer commits to timely compliance documentation
- understanding retailer metering requirements.

Altering existing connections

Common alterations include upgrading capacity (higher amperage, three-phase conversion), adding distributed generation, converting temporary supply to permanent supply, relocating connection points, or decommissioning. The process mirrors new connections: application, assessment, quotation, acceptance, construction if needed, and commissioning.

Decommissioning requires the energy retailer to initiate the request (we cannot act on direct customer requests). Once requested, we safely disconnect the property, remove the meter and return it to the metering company, update the national registry showing decommissioned status, and notify the retailer of completion.

1.6.3 Complaint resolution

If customers have a concern or complaint, we want to hear about it. Customer feedback – even when it highlights problems – helps us identify and fix issues, improve our processes, and deliver better service. Customers can contact us in whichever way suits best: by phone, email, through our website, by letter, or in person during site visits or when visiting our office.

How we handle your complaints

Our complaint resolution process balances speed with thoroughness. We aim to resolve concerns immediately where possible but have structured processes for more complex matters that require investigation.

From first contact to resolution

When a concern is raised, we attempt immediate resolution. If the team member can address the issue straight away and the customer is satisfied with the outcome, we record a summary of the conversation and resolution for our records, and the matter is closed. Many straightforward issues, such as simple billing queries, clarification of charges, scheduling questions, or minor service matters, are typically resolved this way without needing formal processes.

If we cannot resolve the complaint immediately, it enters our formal process. The complaint is recorded in our system, passed to our Corporate and Customer Relations team who specialise in complaint handling, and all relevant information is gathered, including contact details, the nature of the concern, any supporting documents or photographs provided, and relevant background from our systems and records.

Within two working days of receiving the complaint, we send written acknowledgement. This acknowledgement confirms receipt of the complaint and provides a reference number for tracking, outlines our complaint resolution process and timeframes, and provides information about Utilities Disputes. This includes a free, independent dispute resolution service available to customers, and gives the name and contact details of the person handling your complaint. This acknowledgement ensures our customer knows their complaint is being taken seriously and what to expect next.

Our Corporate and Customer Relations team then investigates thoroughly. They gather all relevant facts and information from our systems, records, and field operations. They consult with technical teams or field staff as needed to understand what occurred and why. They review any documentation, photographs, inspection reports, or other records related to the complaint. Throughout this investigation, they consider the customer's perspective and concerns alongside our operational requirements and constraints. Based on this investigation, they develop a proposed resolution that addresses our customer's concerns while being fair and reasonable for all parties.

Most complaints are resolved within five working days. However, some matters require detailed investigation – perhaps involving site visits, technical analysis, consultation with multiple teams, or review of complex situations – and may take up to 20 working days. If investigation reveals that more time is needed beyond 20 days, we discuss this with the customer. With their agreement, we can extend the investigation timeframe by a further 20 working days. We keep our customer informed throughout this process, so they know what is happening and when to expect resolution.

Before presenting any solution, the proposed resolution is reviewed and approved internally to ensure fairness and reasonableness. We then present our proposed resolution to our customer with a clear explanation of our findings and what our investigation revealed, the proposed action or remedy we are offering, our reasoning for this resolution, and why we believe it is fair. We also outline next steps depending on whether our customer accepts or does not accept the proposal.

Outcomes and independent resolution

If our customer is satisfied with the proposed resolution, we implement it and close the complaint. We may follow up after implementation to ensure the resolution was effective and the customer remains satisfied. Their feedback on our complaint handling helps us improve these processes.

If the customer is not satisfied with our proposed resolution, the matter reaches "deadlock". This is a point where we have been unable to reach mutually agreeable resolution through our internal processes. At this point, the customer has options for independent resolution. Utilities Disputes is a free, independent dispute resolution service specifically for electricity and gas customers. Utilities Disputes can facilitate resolution between the customer and us through independent investigation and mediation. We participate fully and cooperatively in the Utilities Disputes process. Depending on the nature of the complaint, other bodies may also be relevant, including the Electricity Authority for industry rule matters, the Ombudsman for administrative concerns, or the Commerce Commission for competition-related matters.

We provide full information about these independent resolution options in our acknowledgement letter and throughout the complaint process, so customers always know what avenues are available if they remain dissatisfied with our response.

Learning from complaints

We track and analyse complaint data to drive service improvement. We monitor the number of complaints received across different categories – reliability, connections, billing, safety, vegetation management, and others – to identify trends and patterns. We track resolution timeframes to ensure we are meeting our service standards and identify any process bottlenecks. We analyse resolution outcomes – including customer satisfaction, deadlocks, and Utilities Disputes referrals – to understand where we succeed and where we need to improve. We review Utilities Disputes outcomes to learn from independent assessments of our complaint handling. Most importantly, we look for themes and trends that indicate systemic issues requiring broader action.

This information directly informs service improvement initiatives. For example, if we see increasing complaints about connection timeframes, we prioritise resources and process improvements in that area – exactly as we have done with the Service Delivery Team enhancements described in section 1.5.2. Complaints about communication during outages led to our enhanced SMS alert system and online outage mapping. Feedback about pricing clarity drove improvements in how we structure and explain quotations. Customer complaints, even when they reflect problems, help us identify and fix issues that benefit all customers.

Our commitment

We commit to treating every complaint with care and respect, regardless of the issue or how it is raised. We commit to keeping you informed at every step of the complaint resolution process so our customers never feel left in the dark. We act on feedback to improve our services, ensuring complaints lead to meaningful change. Our decision-making is transparent and fair, balancing your concerns with operational realities and the interests of all customers. We seek timely resolution wherever possible, understanding that unresolved complaints cause frustration and uncertainty. We participate fully in independent dispute resolution when requested, respecting the role of independent oversight.

Customer feedback helps us improve. Even if customers are dissatisfied with an outcome, we value hearing from them and learning how we can do better. Every complaint is an opportunity to strengthen our service and build trust with our community.

Kaikōura

1.7
How we compare: industry benchmarking

Industry benchmarking against other EDBs is a task we regularly undertake to measure how we perform. By comparing key metrics such as reliability, cost efficiency, and customer service levels, we gain valuable insights into our strengths and areas for improvement. This process enables us to set realistic targets, adopt best practices from leading networks, and ensure our services remain competitive and responsive to customer needs. Regular benchmarking also fosters transparency and accountability, reinforcing our commitment to delivering high-quality, value-for-money service to our community.

1.8 Changes in forecast expenditure

We do not expect changes in forecast expenditure that would materially affect performance definitions within the current reporting year (FY26). However, several factors could lead to material differences between forecast and actual results over the 10-year planning period. Understanding these factors helps to manage expectations and explain potential variances when actual outcomes differ from forecasts.

Kainga

1.8.1 Factors that may cause expenditure variations

Table 1.8 summarises the key factors that could cause material differences between forecast and actual expenditure or performance over the planning period.

Table 1.8 Factors affecting forecast expenditure

Factor	Expenditure impact	Performance impact	Potential magnitude	Mitigation strategies
Customer growth and connection demand	**Capital:** Network extensions, capacity upgrades, new connection infrastructure **Operational:** Additional asset maintenance, increased service delivery workload, expanded vegetation management	Service levels maintained through timely investment. Delayed investment creates capacity constraints affecting connection timeframes and potentially reliability.	Growth variations of 20–30% from forecast could affect expenditure by similar proportions.	• Early engagement with councils and developers on growth projections • Flexible capital programme allowing acceleration or deferral • Modular network designs enabling staged investment • Regular growth forecast updates
Weather and extreme events	**Operational:** Emergency fault response, temporary repairs, vegetation clearance **Capital:** Permanent reinstatement of damaged infrastructure, contingency expenditure	Excluded from normalised SAIDI/SAIFI but affects total performance and customer experience. Increasing frequency of severe weather drives performance variability.	Single major storm: $1–3 million unplanned expenditure, 100–200 minutes added to annual SAIDI.	• Emergency response capability and contractor arrangements • Network resilience investment • Enhanced vegetation management in exposed areas • Insurance and financial reserves
Asset condition and failure rates	**Capital:** Asset renewal and replacement programme expenditure varies with actual condition and failure rates	Underestimating renewal needs risks increasing failures affecting reliability. Overestimating results in unnecessary expenditure.	Asset condition variations could affect renewal expenditure forecasts by 10–20% in either direction.	• Condition-based risk management approach • Regular condition assessments and monitoring • Failure rate tracking and analysis • Conservative assessments for critical assets with limited visibility
Input cost pressures	**Both capital and operational:** Labour rates, materials (copper, aluminium, steel, oil), equipment (transformers, switchgear), contractor services	Cost escalation beyond forecast requires either reduced work scope (affecting service) or increased expenditure (affecting prices).	Input costs varying 10–15% from inflation assumptions would materially affect expenditure forecasts.	• Competitive procurement testing market pricing • Long-term contractor partnerships for price stability • Alternative materials/designs where feasible • Efficiency programmes offsetting cost increases
Regulatory and compliance changes	**Both capital and operational:** New health and safety requirements, seismic standards, cybersecurity requirements, environmental compliance (consenting, monitoring, mitigation)	Compliance obligations must be met regardless of cost. Non-compliance risks safety, regulatory enforcement, or operational restrictions.	Timing and extent inherently uncertain; can range from minor to material depending on requirement.	• Active monitoring of regulatory developments • Industry engagement on proposed changes • Consultation with Commerce Commission where changes affect price-quality settings • Flexible programme allowing accommodation of new requirements
Technology and innovation impacts	**Capital:** Distributed energy resources integration may require low-voltage network upgrades, voltage management systems, and protection modifications. Electrification may accelerate capacity investment. **Operational:** Technology may enable efficiency savings through predictive maintenance, vegetation management innovation, and process automation.	Technology changes both network requirements (potentially requiring investment) and operational efficiency (potentially reducing costs). Net effect uncertain.	Could materially affect operational expenditure over planning period. Scale uncertain.	• Monitoring of technology adoption trends (EVs, solar, batteries) • Flexible network planning accommodating different scenarios • Strategic investment in enabling technologies where proven • Pilot programmes testing new approaches before broad deployment

Note *All factors interact. For example, extreme weather events may accelerate asset deterioration, compounding renewal requirements. Input cost pressures affect both planned work and emergency restoration. Technology adoption affects both growth patterns and operational efficiency.*

Mt Alexander, Hawarden

1.8.2 Monitoring and response process

We actively monitor expenditure and performance to identify emerging variances early and respond appropriately. Our monitoring framework is summarised in Table 1.9.

Table 1.9 Expenditure and performance monitoring framework

Monitoring activity	What we track	Frequency	Purpose	Who is responsible
Financial reporting	• Actual expenditure vs budget (all categories) • Variance analysis and drivers • Rolling forecast updates	Monthly	Identify expenditure variances, understand drivers, update forecasts based on trends	Finance team, reported to Executive and Board
Performance monitoring	• SAIDI, SAIFI vs targets • Safety metrics • Customer satisfaction scores • Variance investigations	Monthly	Track service delivery against targets, identify adverse trends, link performance to expenditure	Operations and Customer teams, reported to Executive and Board
Customer satisfaction focus	• Communication (6.7/10 current, 7.0 target) • Engagement effort (6.6/10 current, 7.0 target) • Timeliness (6.4/10 current, 7.0 target) • Website (5.4/10 current, 7.0 target) • Quality (5.3/10 current, 7.0 target)	Quarterly deep dive (ongoing data collection)	Monitor Service Delivery Team improvements and system enhancements, ensure initiatives remain on track	Customer Relations team, reported to Executive
Work programme delivery	• Capital programme completion rates • Maintenance programme completion rates • Resource utilisation and productivity • Deliverability assessment	Monthly	Identify slippage or acceleration, adjust resource allocation, assess future programme deliverability	Asset Management and Delivery teams
Risk monitoring	• Emerging risks or changed risk profiles • Potential impacts on expenditure or performance • Mitigation effectiveness	Ongoing, formal review quarterly	Trigger mitigation responses, inform planning adjustments, update risk register	Risk team, reported to Executive and Board

When we identify material variances between forecast and actual expenditure or performance, we follow a structured response process, which is outlined in Table 1.10.

Table 1.10 Material variance response process

Response step	Description	Key questions/considerations	Outcome
1. Root cause analysis	Determine what is driving the variance	• External factors beyond control (e.g. weather events, market conditions)? • Internal performance issues (e.g. productivity, project management)? • Forecast accuracy issues (e.g. optimistic assumptions, unforeseen requirements)? • Combination of factors?	Clear understanding of variance drivers enabling appropriate response
2. Impact assessment	Determine effects of variance	• Performance outcomes: Will service levels be affected? • Financial position: What are funding implications? • Regulatory compliance: Does variance affect price-quality path limits? • Customer outcomes: Will prices or service be affected?	Quantified assessment of variance significance and stakeholder impacts
3. Response definition	Develop appropriate actions	• Corrective actions for internal performance issues • Reforecasting incorporating new information • Plan adjustments (defer lower priority, accelerate higher priority) • Efficiency initiatives offsetting cost increases • Combination of responses	Defined action plan addressing variance with clear accountabilities and timeframes
4. Implementation	Execute the response	• Work programme changes • Resource reallocation • Process improvements • Technology or systems changes • Organisational adjustments	Variance addressed, expenditure and performance returning to acceptable trajectory
5. Reporting	Transparent communication of variance and response	• Annual AMP updates to Commerce Commission • Information disclosure reporting with explanatory commentary • Stakeholder communication where variances affect service or pricing • Internal reporting to Executive and Board	Stakeholders informed, regulatory obligations met, governance oversight maintained

Materiality thresholds: We consider variances material if they meet one or more of the criteria shown in Table 1.11 below.

Table 1.11 Materiality thresholds for reporting

Criterion	Threshold/Description
Performance impact	Affects performance against disclosed targets by more than 5%, indicating significant service level change
Expenditure impact	Changes expenditure forecasts by more than 20%, indicating substantial financial impact
Work programme impact	Requires significant changes to work programmes or priorities beyond normal year-to-year optimisation
Customer impact	Affects customer prices or service levels in ways customers would notice and care about
Regulatory impact	Requires regulatory consultation or approval under information disclosure or price-quality path provisions

Note *Specific threshold values are determined based on an assessment of materiality that is appropriate to MainPower's scale and circumstances.*

Any material variance in expenditure affecting network performance is reported in our annual AMP updates and information disclosure reports. Our internal governance processes ensure appropriate management oversight of expenditure and performance, with Board-level review of any material variances and response strategies. This governance ensures that variances receive appropriate attention and that responses balance short-term pressures with long-term network stewardship objectives.

2
Delivering for our communities: people, capability, and resilience

This section explains how we deliver reliable electricity services through both our physical network infrastructure and our organisational capabilities. We show you the network that serves your community, how we monitor and maintain power quality, how we communicate with you during outages, and the people, systems, and practices that enable us to deliver this AMP.

What you will find in this section

- Who we are and how we deliver for our customers and communities
- How we manage risk and increase resilience
- Keeping our people and our customers safe
- Our environmental impacts and how we manage these
- What the electricity network is and our place in it
- Climate change challenges and how we're preparing for them
- Our business continuity planning and emergency response protocols
- Network configuration and future network developments
- Our customer interface and service linkages
- Non-network solutions and distributed energy

2.1
Powering our communities: who we are and how we deliver

This section introduces who we are, how we operate, and the people and systems behind the reliable service our customers experience every day. It explains how we deliver electricity safely and efficiently across North Canterbury, and how our organisational capability supports the outcomes in this AMP.

Kaikōura

2.1.1
Who we are

We are MainPower New Zealand Limited, a community-owned EDB that has proudly served North Canterbury for more than a century. We supply over 46,000 homes and businesses across the Waimakariri, Hurunui, and Kaikōura districts, connecting the lives of nearly 90,000 people.

We are owned by the MainPower Trust, which represents our consumer-shareholders. That means every decision we make is guided by what is best for our customers and communities, not external investors.

As our region grows, we are focused on maintaining service quality, supporting new technologies like EVs and solar panels, and preparing our network to withstand more frequent extreme weather events. Figure 2.1 gives a snapshot of the size of our network, the number of connections we service, and our service area.

Our network at a glance

Circuit length

5,800 km

Connections

46,000+

Peak demand

115 MW

Service area

10,000 km²

Figure 2.1 The MainPower network at a glance

Role of the Board

Our Board of Directors is responsible for overseeing how we operate as a company. The Board guides our overall direction and decision-making, working on behalf of both the Trust and our preference shareholders.

The main goal of the Board is to honour our shareholders' desire for long-term value, which we achieve by focusing on excellent customer service and helping our region prosper. We measure customer service based on the financial returns we deliver, our ability to provide secure and reliable electricity, our responsiveness, quality, and how we compare on price.

Supporting regional growth is also important to us. We do this by leading or supporting local economic development initiatives. The Board is committed to making sure we are a good employer and a responsible member of our community.

Strategic Asset Management Steering Group

We have a dedicated steering group to provide oversight and direction for our asset management strategies. This group helps ensure there is a strong connection between our Board and the teams managing our assets.

Our Senior Leadership Team

Our Senior Leadership Team is responsible for the day-to-day management of our business and ensuring we deliver on our commitment to our community. Composed of experienced professionals from diverse backgrounds, the team provides strategic guidance, operational oversight, and expert leadership across all key functions. Together, they work closely with the Board of Directors and the Strategic Asset Management Steering Group to drive innovation, uphold high standards of service, and foster a positive workplace culture.

The team's collective expertise covers critical areas such as assets and operations, service delivery, finance and information technology, customer and corporate relations, commercial, and people and culture. By championing collaboration and continual improvement, our leaders ensure we remain agile and responsive to the needs of both our customers and our region. Figure 2.2 outlines our executive structure, including our business units.

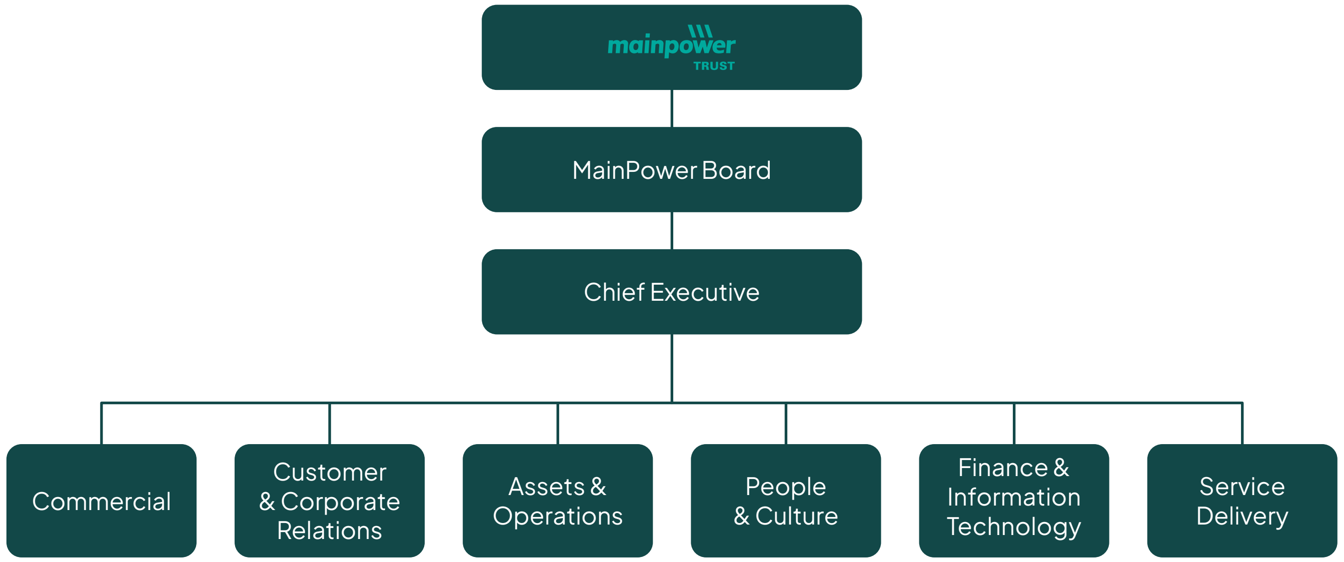


Figure 2.2 Our executive structure

2.1.2 How we deliver for you

Delivering power reliably requires more than poles and wires, it depends on skilled people, proven systems, and strong partnerships.

Table 2.1 shows how our business functions work together to ensure we are delivering efficient and effective services that are transparent and future focussed.

Table 2.1 MainPower operations

Function	Description	What it means for customers
Field services	In-house crews supported by specialist contractors maintain, repair, and upgrade the network.	Faster fault response and direct accountability for quality.
Asset management & planning	Engineers and planners model future demand, assess risk, and prioritise investments using lifecycle principles.	Investments targeted where they deliver the greatest customer benefit.
Control centre & network operations	Staff monitor the network 24/7 using advanced systems to manage outages and coordinate restoration.	Quicker identification of faults and shorter outage durations.
Customer & community engagement	Dedicated teams handle enquiries, outages, and new connections, and gather feedback to shape our plans.	You can easily contact us, track updates, and have your voice heard.
Corporate services & governance	Board and Executive leadership ensure safety, compliance, and financial prudence.	Confidence that your network is well-governed and responsibly managed.

Our mixed delivery model ensures resilience and cost-effectiveness. We maintain skilled internal teams for core operations, complemented by long-term contractor partnerships for specialised or surge work. This flexible approach means we can scale rapidly during major outages or project peaks without compromising service quality.

Our delivery model

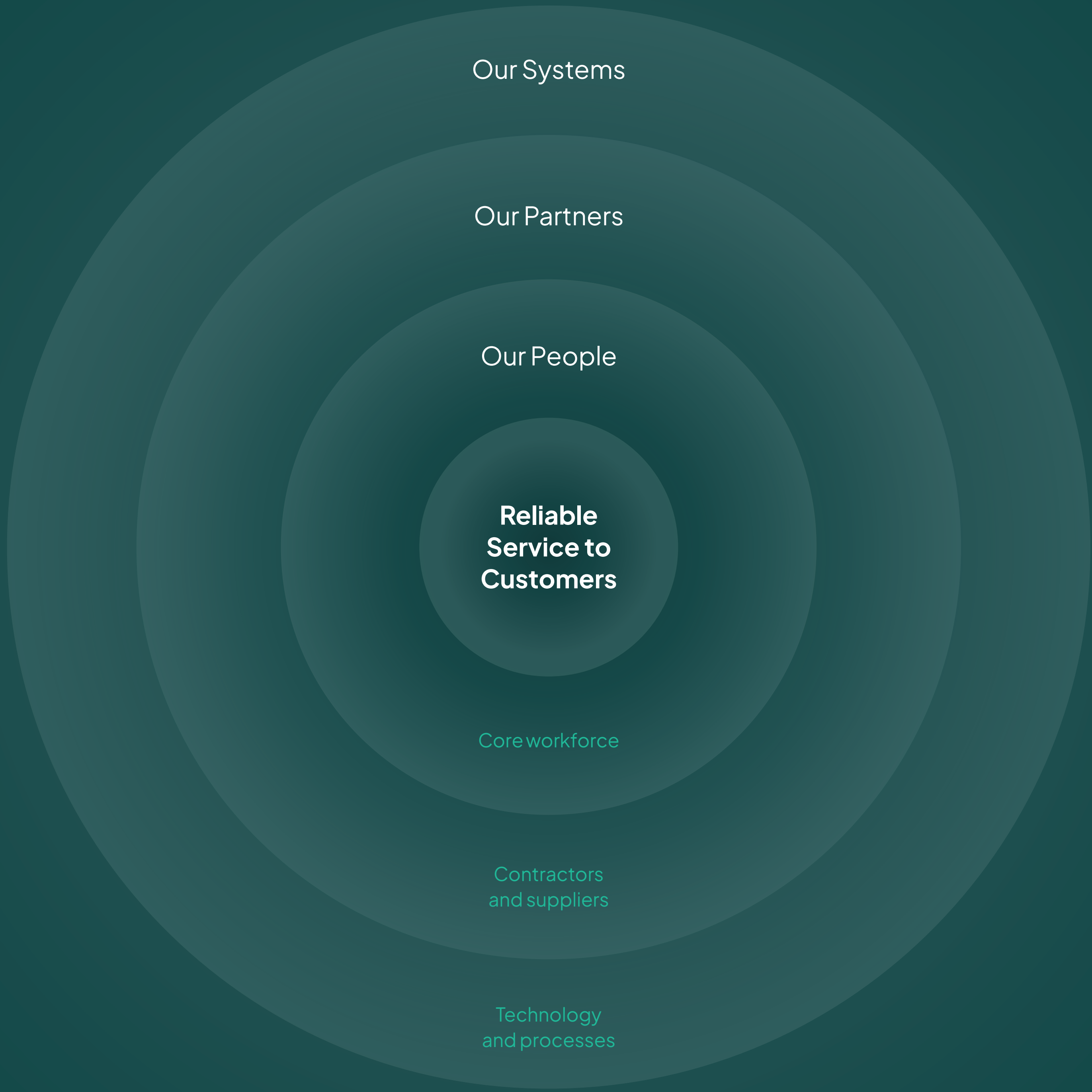


Figure 2.3 Key elements in our delivery model

2.1.3 Our people and culture

Behind every line mechanic, engineer, and customer service representative is a commitment to public safety and community service. We invest heavily in apprenticeships, technical training, and leadership development to sustain local capability.

Our values of *do what's right*, *make it happen*, *make it better* and *work together* guide how we work and how we serve our customers.

We operate under an accredited safety management system aligned with ISO 45001[4] and we are aligning our asset management practices with ISO 55001[5] requirements. Regular competency assessments and refresher training ensure every person working on or near our network meets high safety and technical standards.

2.1.4 Our commitment to you

Everything we do, including planning, investment, maintenance, and emergency response, is driven by our commitment to deliver value to our customers and communities.

Figure 2.4 Our commitment to our customers

When you flick the switch, our people, systems, and partners have already done the work to make that moment possible.

[4] *ISO 45001 is an international standard for occupational health and safety management systems.*

[5] *ISO 55001 is an international standard that specifies the requirements for an asset management system.*

2.2
Managing risk and building resilience

Delivering reliable electricity depends on how well we plan for the unexpected. This section explains how we identify, assess, and manage risks that could affect the safety, reliability, and affordability of your electricity supply. It also shows how we strengthen our network and operations to remain resilient during storms, natural disasters, or other major events.

2.2.1 Our approach to managing risk

Every day, we make decisions that balance reliability, safety, cost, and environmental responsibility. Our enterprise risk management framework guides these decisions so that risks are identified early, managed consistently, and linked to the outcomes customers care about most.

Our risk management approach is aligned with ISO 31000:2018 and integrated into our ISO 55001–aligned asset management system. It provides a consistent way to assess both operational and strategic risks across the business, from equipment condition to cyber security.

Our framework, as shown in Figure 2.5, is built around five principles:

- Identify risks across all operations – from asset failure and weather impacts to supply chain and cyber threats.
- Assess likelihood and consequence using a standard risk matrix and quantified scoring.
- Mitigate through targeted actions: maintenance, investment, insurance, or operational controls.
- Monitor progress and the effects of actions and mitigations.
- Review to ensure controls remain effective as conditions change.

Figure 2.5 Our Risk Management Cycle

Risk management is overseen by the Executive Leadership Team, reported quarterly to the Board Audit and Risk Committee, and embedded into daily decision-making through planning, procurement, and project management systems.

2.2.2 Identifying and assessing key risks

Our risk register groups potential events into four broad categories that together capture the full range of challenges our network may face. Table 2.2 shows our key risk categories and what they mean for you.

Table 2.2 Key risk categories and controls

Risk category	Description	Typical controls	What it means for customers
Network and asset risks	Failure or deterioration of equipment; capacity shortfalls	Preventive maintenance, asset renewal, network automation	Fewer unplanned outages and faster restoration
External and environmental risks	Severe weather, earthquakes, fires, or flooding	Resilience investment, vegetation management, design standards, insurance	Resilient supply when adverse conditions have impacted the network
Business and technology risks	System outages, data loss, cyber security, supply-chain disruption	IT security controls, business continuity planning, supplier management	Continued service despite digital or logistical disruption
Financial and compliance risks	Cost pressures, regulatory change, or non-compliance	Prudential monitoring, internal audit, staff training, legal review	Efficient, transparent operations and fair pricing
People and safety	Managing risks to worker and public health and safety	Training, communication, engineering, personal protective equipment (PPE), audits	Managing risk as low as reasonably practicable

We update the risk register regularly using incident data, network performance trends, climate projections, and stakeholder feedback. Significant risks are reviewed quarterly with clear accountabilities and mitigation plans.

Kainga

2.2.3 Building network resilience

Resilience means being able to withstand shocks and recover quickly. Our approach combines prevention, preparedness, response, and recovery. Figure 2.6 shows the key actions we are taking to increase resilience across the network.

Layers of resilience

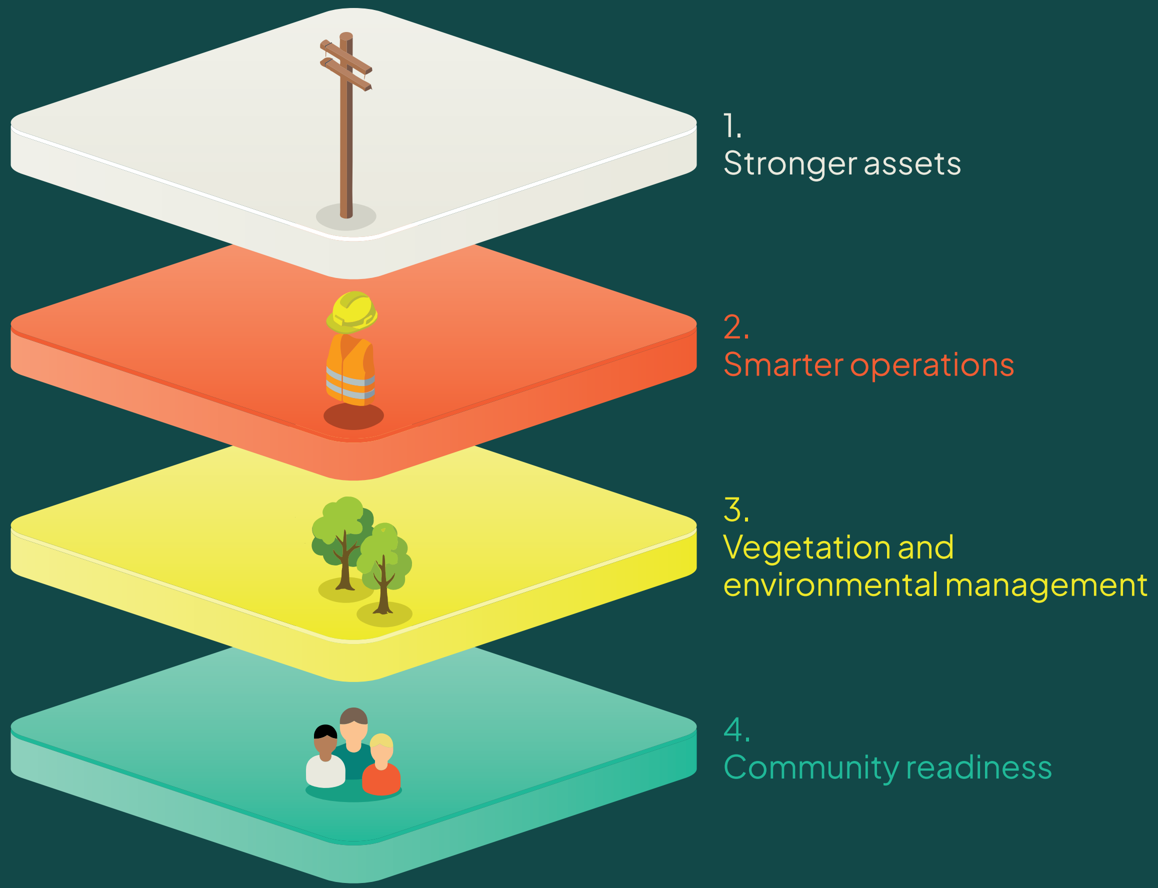


Figure 2.6 Key aspects identified for increased resilience

1. Stronger assets:
We design and maintain the network to standards appropriate for local conditions. Pole specifications, conductor strength, and foundation design are reviewed to withstand severe winds and snow loading. Critical substations are assessed for seismic, extreme weather, and flood risks.

2.Smarter operations:
An advanced distribution management system (ADMS) provides real-time visibility and remote switching capability, enabling faster fault isolation and restoration. Geographic information system (GIS) data and predictive analytics help us analyse the network.

3.Vegetation and environmental management:
Our vegetation programme uses satellite imagery and AI-based analytics to prioritise tree trimming where it most reduces outage risk. This helps reduce the effect of storm-related faults.

4. Community readiness:
We coordinate with local civil defence emergency management (CDEM) groups and Canterbury Lifelines, emergency services, and local councils to ensure restoration priorities are clear and critical facilities (hospitals, water supplies, and communication sites) are supported first.

2.2.4 Responding to emergencies and major events

When major events occur, our emergency management framework, as illustrated in Figure 2.7, ensures rapid and coordinated response. It aligns with the national CDEM framework and is regularly tested through exercises.

Key features include our:

- **Business Continuity Plan**, which maintains essential functions such as fault response, control room operations, and communication during disruptions
- **Emergency Response Plan**, which defines activation triggers, roles, and communication channels during large-scale outages
- **Mutual Aid Agreements**, which enable resource sharing with neighbouring EDBs during widespread events
- **Critical-Asset Register**, which identifies substations, feeders, and customer facilities that require priority restoration
- **Post-event Review,** which is a process that allows us to capture lessons learned from the event to improve our future response.

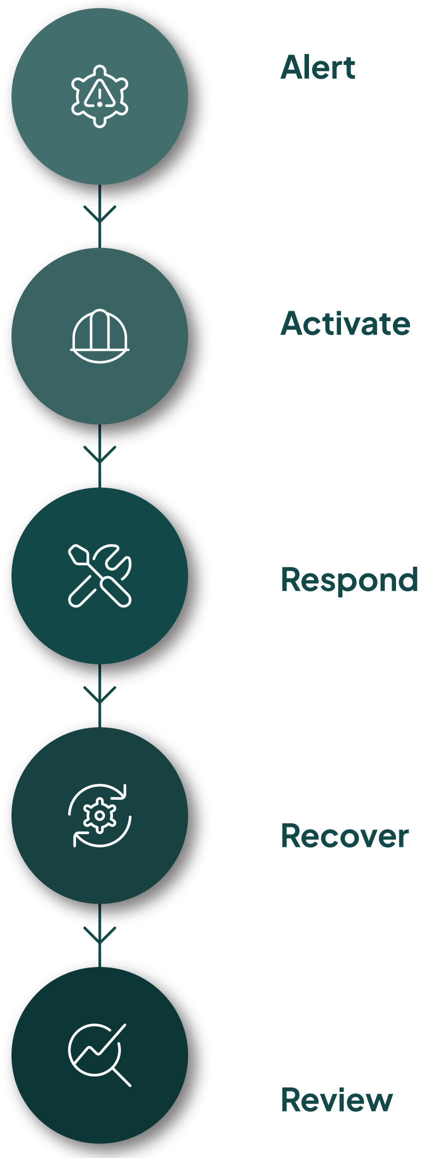


Figure 2.7 Our five-stage emergency response framework for major events and emergencies

2.2.5 Climate and natural hazard adaptation

Climate change is altering the frequency and intensity of severe weather events. We are acting now to strengthen the network and adapt our operations to future conditions.

Table 2.3 shows the key climate impacts for our region.

Table 2.3 Key climate impacts for our region

Impact	Observed or expected change	Our response
Severe storms and high winds	Increasing frequency of damaging weather events	Stronger pole and line designs; vegetation management using predictive tools
Flooding and erosion	More frequent flooding affecting infrastructure and access routes	Flood-tolerant designs, relocation of vulnerable assets
Wildfire risk	Hotter, drier summers increasing vegetation-fire exposure	Enhanced line-clearance zones, coordination with Fire and Emergency NZ
Heat stress on equipment	Higher average temperatures affecting equipment performance	Temperature-rated equipment and real-time thermal monitoring
Seismic risk	Ongoing risk across North Canterbury fault lines	Seismic assessments and strengthening of critical substations

These initiatives are guided by our Climate Resilience Roadmap, which aligns with national adaptation guidance and regional hazard management plans.

2.2.6 What this means for you

Our customers can have confidence that MainPower is proactively managing the risks that matter most.

Fewer interruptions from asset failures and weather events

Faster recovery after storms or natural disasters

Safer communities through coordinated emergency planning

Sustainable costs by investing where risk reduction delivers real value

By understanding and managing risk well, we protect both the reliability of your electricity supply and the resilience of our communities.

Kaikōura


Kainga

2.3
Keeping people safe

Safety is the foundation of everything we do. Every person who works on, lives near, or depends on our network deserves to go home safe each day. This section explains how we protect our workers, contractors, and the public, and how our safety culture supports reliable, responsible service delivery.

2.3.1 Our commitment to safety

We believe every incident can be prevented through clear standards, capable people, and a culture that values safety above all else. Figure 2.8 illustrates how our culture begins at the top and is part of our systems and people management to underpin safe outcomes for all.

This commitment extends beyond compliance to genuine care for our people and our communities. We maintain a certified Safety Management System aligned with ISO 45001 and integrated with our asset management framework.

This system defines clear accountabilities, from the Board and Chief Executive to every field crew member, and is independently audited for continual improvement.

Before any work begins, our teams assess risks, agree on controls, and confirm that conditions are safe. All incidents and near-misses are recorded, reviewed, and followed by improvement actions. We also apply critical-risk bow-tie analysis to the 10 safety-critical and 5 business-critical risks identified in our enterprise framework (see section 2.2).

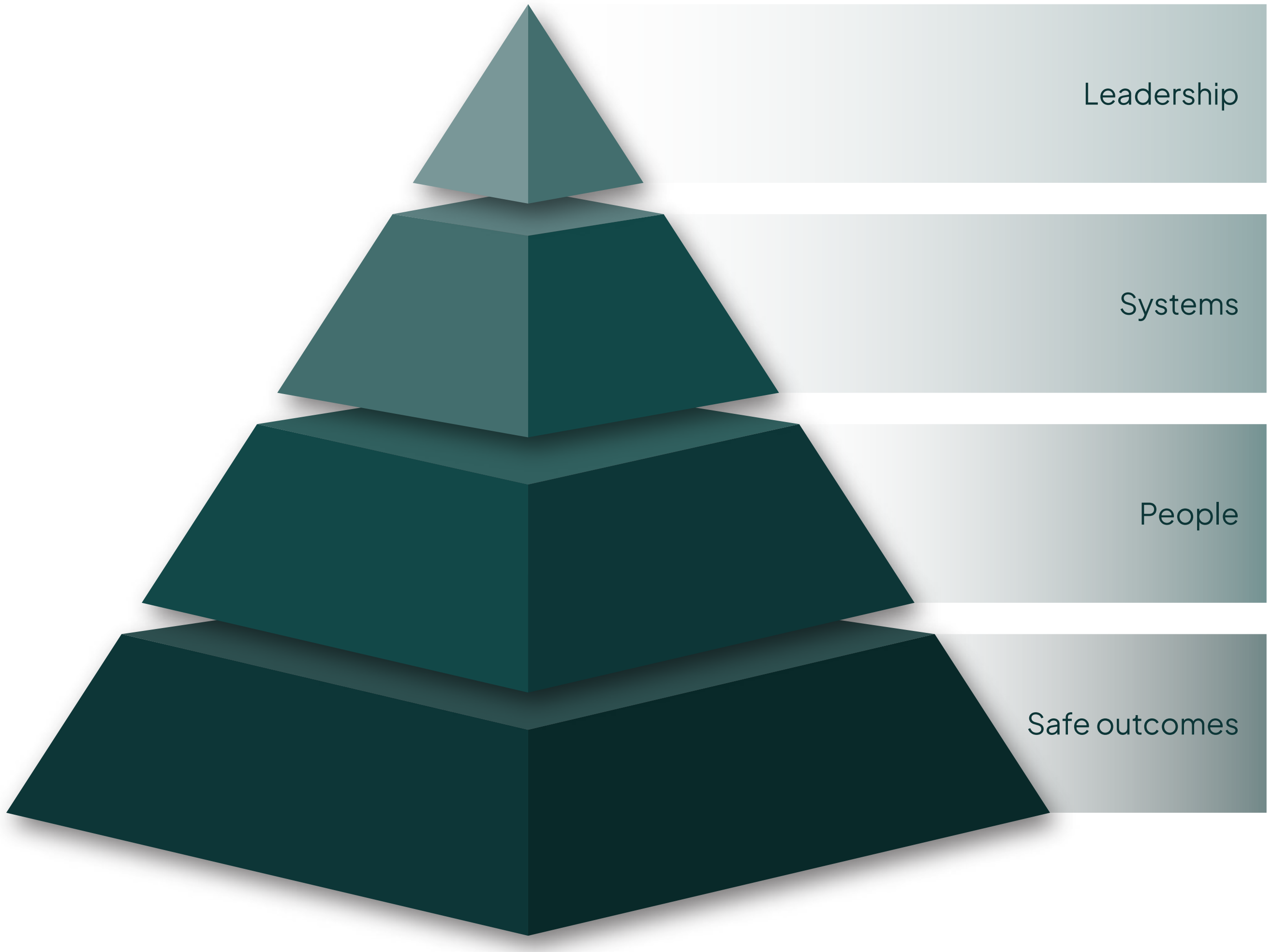


Figure 2.8 Our Safety Framework

2.3.2 Our safety culture

A strong safety culture depends on effective worker participation and leadership at every level. We promote a Just and Fair Culture approach – one where our people are empowered to speak up, stop work if something feels unsafe, and suggest improvements. Leaders are visible and engaged, regularly joining site visits, safety conversations, and toolbox meetings.

We track our culture through independent surveys, incident trends, and staff engagement results. Open reporting and learning are key: every event is treated as an opportunity to strengthen systems and share lessons across teams.

2.3.3 Protecting the public

Keeping our communities safe is central to our purpose. We manage public safety risks such as trees near lines, vehicles contacting poles, and damage to underground cables through education, design, and proactive inspection.

Key elements of our programme include:

- **safety education** in schools and community groups, promoting respect for electricity and awareness of hazards
- **seasonal campaigns** on tree trimming, storm preparation, and staying clear of fallen lines
- **safe network design** using insulated conductors, barriers, and clearances in high-risk areas
- **partnership with councils and emergency services** to manage incidents quickly and prevent recurrence.

These initiatives help maintain a culture of safety and reinforce shared responsibility between the company and our customers.

Hanmer Springs

2.3.4 Worker health and wellbeing

We support the physical and mental wellbeing of everyone who works for or with us. Health and wellbeing programmes cover fatigue management, ergonomics, and mental-health awareness. All staff and contractors have access to confidential counselling and employee assistance services.

We monitor fatigue risk, especially during extended storm response or seasonal workload peaks. Every contractor working on our network is pre-qualified for safety competence and must follow the same standards as our employees.

2.3.5 Learning and continual improvement

Safety improvement never stops. Every incident or near-miss is investigated to identify causes and corrective actions, which are tracked to completion. Findings are shared across teams through regular safety briefings and the company intranet.

We benchmark our safety performance against other EDBs and participate in Electricity Engineers' Association forums to exchange best practice and innovation. External audits and peer reviews confirm that our systems remain robust and fit for purpose.

For detailed performance results, including our latest safety and environmental metrics, refer to section 1.3.5.

2.3.6 What this means for you

Our safety culture protects everyone connected to our network. It means:

- safe, well-designed equipment near your home or business
- crews who work carefully and follow proven procedures
- fewer outages caused by unsafe conditions
- continual learning to keep improving safety and reliability

By keeping people safe, we strengthen the trust that powers every connection across North Canterbury.


Culverden

2.4 How we manage our impact on the environment

We believe that building a sustainable future means taking responsibility for the impact our operations have on the environment. Every day, we look for practical ways to reduce our environmental footprint and make sure that our actions today support a healthier tomorrow. To ensure we meet high standards, we have set up an Environmental Management System as part of our wider Integrated Management System. This system follows the internationally recognised ISO 14001:2015 standard, which helps us plan, manage, and review our environmental responsibilities in a structured way.

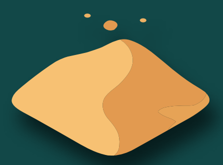
Our approach is built around several key principles. First, we know that safeguarding the environment now is vital for our long-term success. That's why we comply fully with all relevant environmental laws and regulations, and we keep up to date with any changes. We believe strong communication is essential, so we regularly consult and involve our team in discussions about environmental matters. This ensures everyone has a voice and helps us spot opportunities for improvement.

We also take care to identify and manage environmental risks across all our activities. We act responsibly, taking every practical step to protect our people and customers while delivering reliable, high-quality service. Setting clear goals and regularly measuring our environmental performance allows us to keep track of how we're doing and share progress with our team and stakeholders.

Continual improvement is a priority for us. We are always looking for ways to prevent pollution, reduce waste, and limit any negative impact our work might have on the environment. Ongoing training and support are provided for our team, helping everyone stay up to date with best practices and build their knowledge in environmental management.

If any environmental incidents do occur, we make sure to investigate fully, understand what happened, and take steps to prevent similar issues in the future. We also work closely with our business partners, the communities we serve, and other stakeholders to encourage shared responsibility and promote environmental sustainability together.

2.4.1
Environmental hazards



Dust

Dust is often created when we disturb materials like wood, stone, or concrete, and can sometimes be too small to see but still harmful when breathed in. We take practical steps to limit dust in the air and reduce exposure. This includes using dust suppression techniques, providing appropriate protective equipment, and ensuring our tools and work areas are regularly cleaned. We clearly mark any areas where dust is a concern and monitor conditions to make sure safety measures stay effective.

Noise

Noise, or unwanted sound, is a common part of many of our work activities. However, when noise levels become too high, they can pose real health risks. Exposure to loud or persistent noise can harm hearing, especially if the sound is high-pitched or workers and the public are exposed for long periods. To ensure everyone's safety, we take noise management seriously and follow strict standards.

We comply with all legal requirements, including the Resource Management Act 1991 and any local council rules, to keep noise at safe levels. We aim to make sure that no one, whether it's a member of our team or the public, is exposed to noise levels higher than an average of 85 decibels (dB) over an eight-hour period, or sudden peak noises above 140 dB. These limits apply whether or not hearing protection is worn. Where possible, we remove or reduce noise at its source. Sometimes this means isolating or enclosing noisy equipment, redesigning workspaces, or introducing quieter work methods. We also provide clear information and training, so everyone understands how to work safely around noise. For tasks that must be noisy, we develop clear protocols and schedule work to minimise the time people are exposed. Approved hearing protection is supplied when needed, and we clearly signpost areas where extra precautions are required.

If you ever have concerns about noise levels, we encourage you to report it. Raising concerns helps us respond quickly and keep everyone safe. Please contact our health, safety, and environment team if you notice anything that might put people at risk.

Contaminated ground

If we suspect the ground may be contaminated or contains materials like asbestos, we stop work in that area straight away. Appropriate controls are put in place to manage the contaminated risks in a way that is safe for our staff and the public.

Management around waterways

We take special care when working near waterways to protect these important natural areas. Wherever possible, we keep machinery at least five metres away from the edge of streams. If we absolutely must work closer, we do so only with careful planning and take every step we can to avoid causing harm.

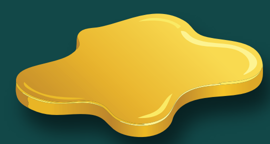
To help keep our waterways clean, any water running off our work sites goes through a silt trap or filter, like a sediment fence, before it reaches the stream. This helps catch soil and debris, stopping it from washing into the water. We also make sure that this run-off is directed onto solid, grassy, or well-covered ground, well away from any areas filled with loose earth.

Pollution control of equipment/plant

We take pollution control seriously to protect our environment. Pollutants such as smoke, gas, fumes, dust, sludge, waste, sewerage, oils, and greases are never released into the air or onto the ground unless we have legal permission to do so under the Resource Management Act. We always dispose of these substances responsibly, aiming to remove or reduce any harm to the environment as much as possible.

SF_6 gas

SF_6 helps our switchgear operate safely, but it's a strong greenhouse gas. We set a target of less than 1% annual loss, and we're meeting that standard. We closely monitor and report any losses to keep emissions as low as possible.



Oil

Oil is used in some of our assets for insulation and cooling. We have systems in place to prevent spills and minimise any impact if they happen.

2.4.2 Cultural artefacts

We recognise the importance of protecting Māori sacred areas and cultural treasures as part of how we manage our assets. New Zealand law, including the Heritage New Zealand Pouhere Taonga Act 2014 and the Resource Management Act 1991, requires us to involve Māori in decisions when our work might affect these special places. These laws also honour the Treaty of Waitangi, ensuring Māori have a say in matters that impact their heritage.

If we come across or suspect any cultural artefacts or taonga while working, we immediately stop work and seek advice from local cultural heritage experts before taking any further action.

We also invite local iwi to bless new works or projects that require significant ground activity, such as the Thongcaster Road Solar Farm. We thank Te Taumata Tapu o Ngāi Tūāhuriri for their whakamoemiti for this project.

Thongcaster Road Solar Farm ground breaking ceremony

2.5 Your electricity network

The previous sections explained who we are, how we deliver, and how we manage risk and safety to keep electricity reliable for our communities. This section focuses on the network itself, the infrastructure that carries electricity from the national grid to your home or business. It shows how we plan for growth, maintain security of supply, and continue delivering reliable service as our region expands.

2.5.1 How power reaches your home

Electricity moves through several stages before it reaches you. Understanding this journey helps explain how each part of the system contributes to reliability and what we are investing in to keep supply secure.

From the five grid exit points (GXPs), electricity flows through our network in stages, with the voltage being reduced at each stage until it reaches the 400 V that powers your home or business. Figure 2.9 illustrates this step-down process.

Stage 1:
Transmission to zone substations (66,000 V or 33,000 V)

From the GXPs, electricity travels at 66,000 V or 33,000 V along subtransmission lines to our 15 zone substations located throughout North Canterbury. These subtransmission lines are the high-voltage power lines you might see on large poles or towers. We have approximately 380 km of subtransmission lines operating at these voltages.

Stage 2:
Distribution network (22,000 V or 11,000 V)

At zone substations, transformers reduce the voltage to 22,000 V or 11,000 V. The electricity then travels through our distribution network (a combination of overhead lines and underground cables) to reach neighbourhoods and communities. This distribution system has a large rural component, with many long power lines reaching isolated properties and small townships. About 90% of the rural distribution network uses overhead lines (the wires you see on poles). In Rangiora and Kaiapoi, about 90% of these main distribution lines run underground instead. We have approximately 3,800 km of distribution lines and cables that operate at 11 kV and 22 kV voltages.

Stage 3:
Final step to customers (400 V)

More than 8,500 distribution transformers (either pole-mounted or ground-mounted) make the final voltage reduction to 400 V. This low-voltage network – approximately 70% underground in urban areas and mostly overhead in rural areas – delivers electricity to your property. Each distribution transformer typically serves 5–15 properties. We have approximately 1,000 km of low-voltage lines and cables completing this three-stage system that efficiently moves electricity from the high-voltage national grid to usable voltage at your home or business.

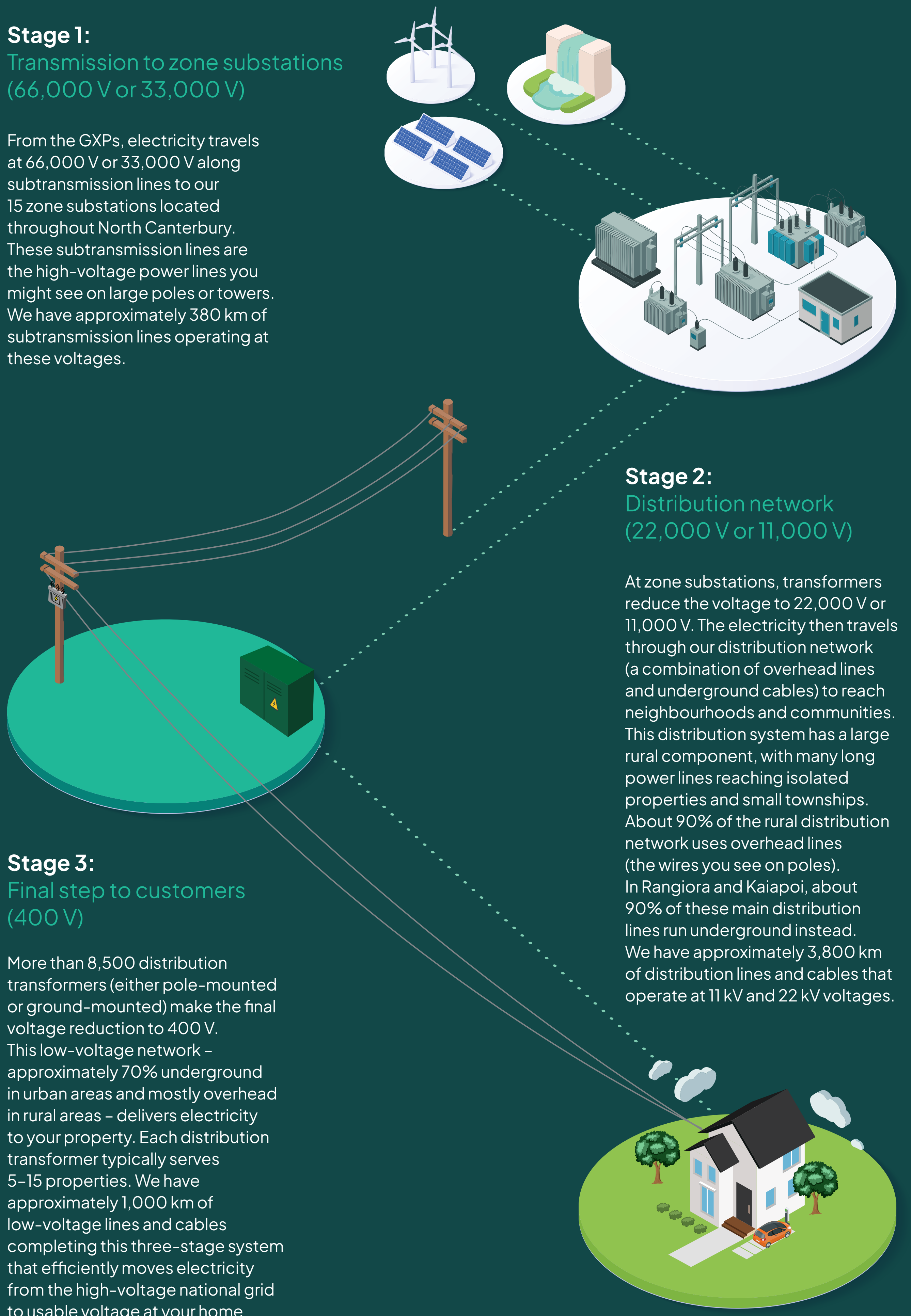


Figure 2.9 How electricity gets from the grid to your home

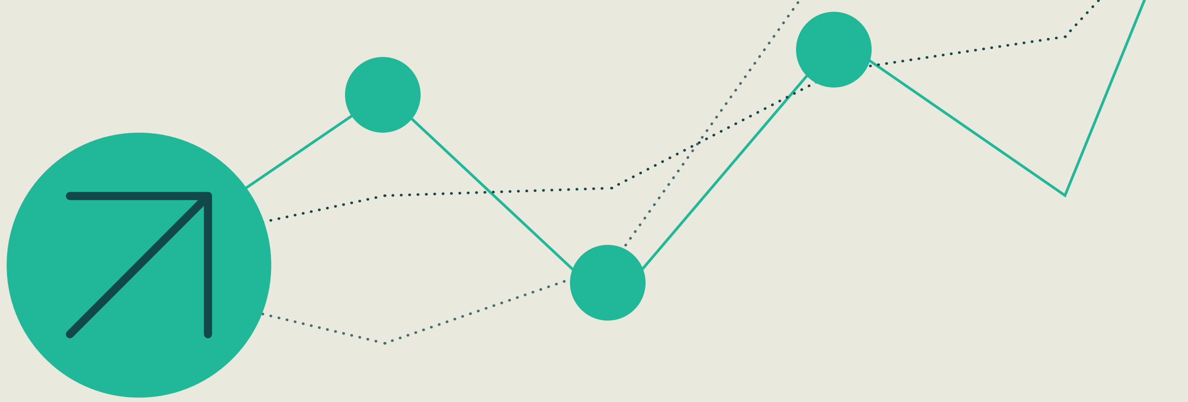
2.5.2 Planning for future electricity demand

Planning for the future starts by modelling how much electricity our region will need in the years to come. This demand forecasting is critical because it drives our investment decisions, helps us identify network constraints before they become problems, and provides the foundation for maintaining reliable service as the region grows.

Our demand forecasting methodology considers:

- population growth and official forecasts for new households from Stats NZ and territorial authorities
- local council plans, including district plan changes, zoning modifications, and infrastructure planning
- upcoming developments, new subdivisions, commercial centres, and industrial areas with confirmed resource consents
- historical demand patterns
- impact of new technologies, including EV uptake, residential solar installation rates, and battery storage deployment
- economic factors, including employment growth, tourism trends, and industrial expansion.

We update our demand forecasts annually using the latest available data. These forecasts inform our capacity planning, investment prioritisation, resilience planning, and network development strategy (as outlined in section 4.4.1). Where forecast demand growth exceeds available capacity within our planning horizon, we evaluate network reinforcement options, demand-side management solutions, and distributed energy resources before committing to network augmentation.



Key demand growth drivers

Several factors are driving significant demand growth across our network over the FY27–FY36 planning period.

Residential development:

North Canterbury continues to experience strong population growth, particularly in the Waimakariri district. Major greenfield developments in Rangiora, Kaiapoi, Woodend, and Pegasus/Ravenswood are forecast to add approximately 400–500 new connections annually. This residential growth requires new distribution infrastructure and reinforcement of existing zone substations to maintain adequate capacity margins.

Climate impacts:

Rising temperatures increase irrigation and cooling demand in summer, while more extreme winter weather events drive higher winter heating demand.

EV adoption:

EV penetration is projected to reach 15–20% of the light vehicle fleet by FY31 and 30–40% by FY36. This represents an additional 8–12 MW of peak demand across our network. EV charging creates both capacity challenges (requiring substation upgrades) and opportunities (for demand management through smart charging).

Irrigation electrification:

In the Hurunui district, land use conversion increasing the use of irrigation systems is forecast to increase electricity demand. While this improves environmental outcomes, it creates electricity supply summer peaking challenges that require targeted capacity management solutions.

Commercial and industrial growth:

Expanding commercial developments in Rangiora and Kaiapoi, combined with potential industrial expansion at existing major sites, contribute to growing demand. We work closely with large consumers to understand their growth plans and incorporate these into our capacity assessments.

Demand growth projections

Based on our analysis of these drivers, we project network-wide demand growth in network peak demand, customer connections and energy consumption, as illustrated in Figure 2.10.

Network peak demand:
Growth from 115 MW in FY26 to 122 MW in FY31 (approximately 1% compound annual growth)

Customer connections:
Increase from approximately 45,600 ICPs in FY26 to 50,000 ICPs in FY31

Energy consumption:
Growth of approximately 5 GWh annually

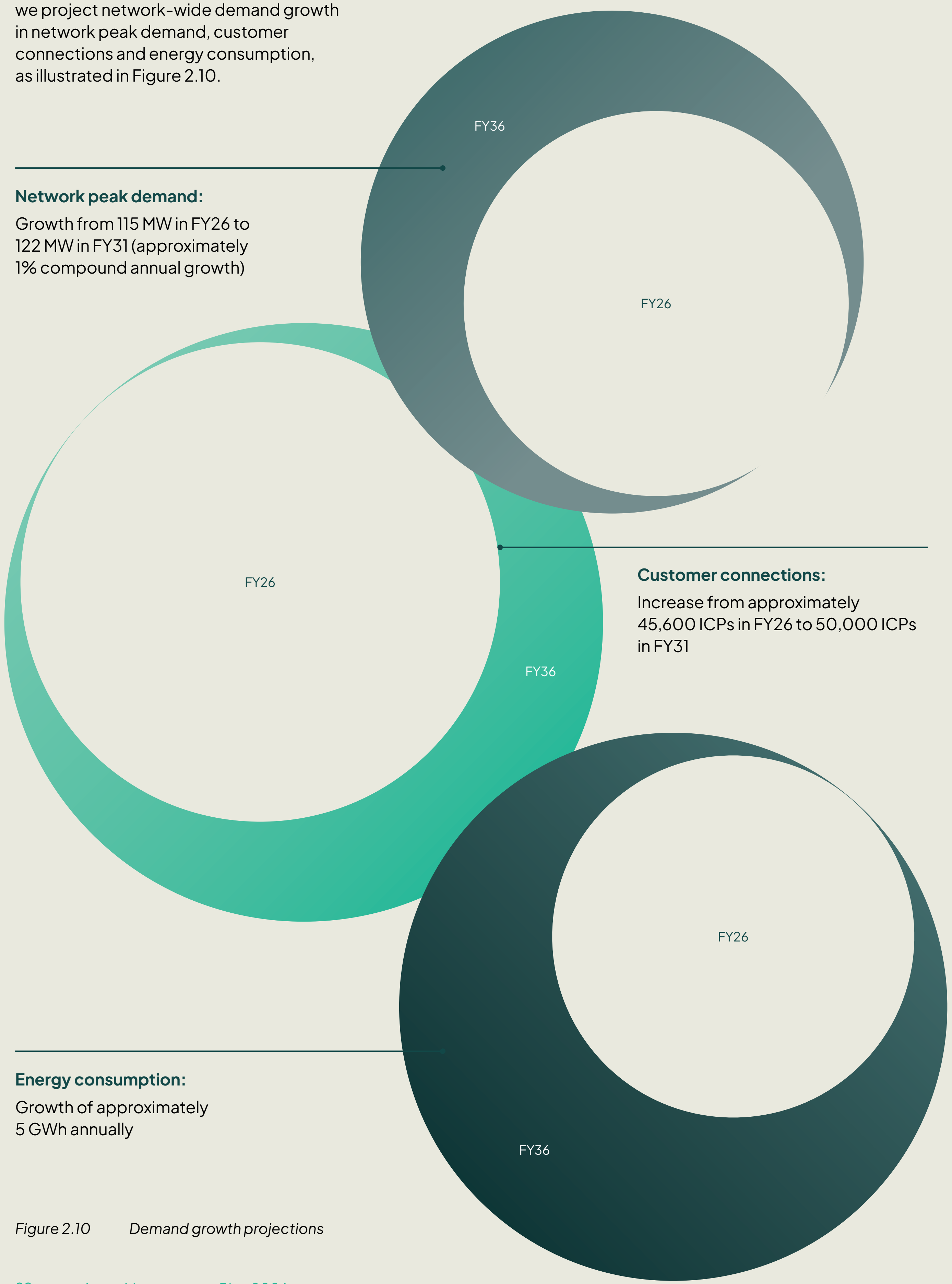


Figure 2.10 Demand growth projections

2.5.3 Network growth trends

Our network continues to grow, with more homes and businesses connecting every year. Figure 2.11 shows the increase in ICPs over FY20–FY25, and our forecast increase for FY26–FY31.

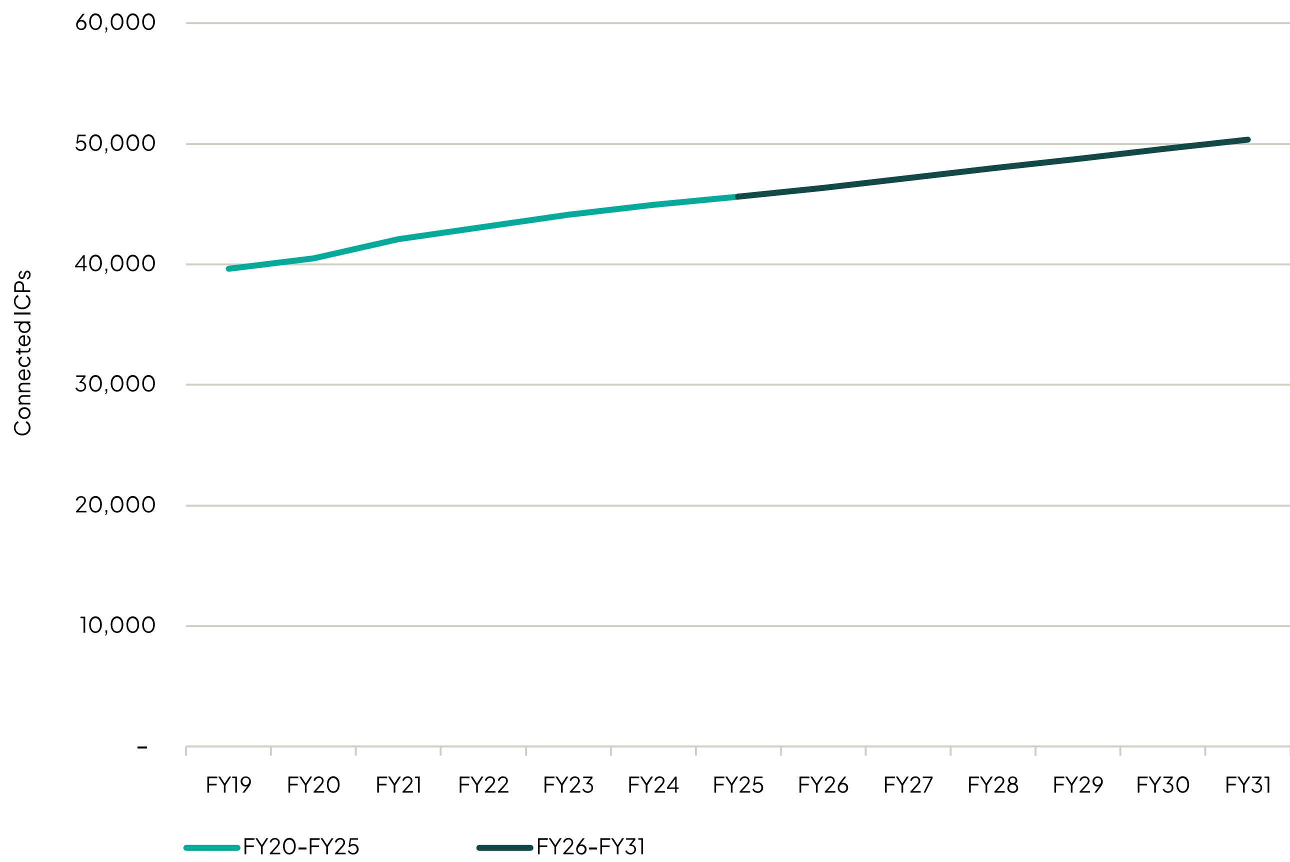


Figure 2.11 Average number of customer connections (ICPs) showing growth from FY20 to FY25 actual and FY26 to FY31 forecast

The majority of this connection growth is concentrated in the Waimakariri district. This reflects several overlapping trends across residential, commercial and rural development.

Much of the expected growth is residential, and is occurring in Rangiora (particularly the northern and western extensions), Kaiapoi (including the Mandeville area), and the continuing staged growth of Pegasus and Ravenswood. Additional housing developments in Woodend, especially north of the existing township, and the ongoing urban expansion of Amberley are also key contributors. At the same time, commercial and retail developments are intensifying in Rangiora's town centre and in the Ravenswood commercial precinct, while rural residential subdivisions are emerging throughout the wider district.

This pattern of growth directly drives the capacity investments identified in our network development plan (see section 4). These include the Coldstream zone substation, network reinforcement projects, and the extension and upgrading of distribution networks to supply new subdivisions. This growth reinforces the importance of the proactive risk management and resilience measures outlined in section 2.2, which help enable network capacity and reliability keep pace with regional development.

2.5.4 Planning by district

We analyse network growth in the three districts on our network: Waimakariri, Hurunui, and Kaikōura. Recognising that each area presents its own set of opportunities and challenges, we customise our planning for each community.

In response to forecast demand growth, we actively monitor electricity usage throughout our network, project future requirements, and evaluate these needs against available network capacity and security of supply standards. This district-level analysis enables us to:

- identify capacity constraints before they impact service reliability
- prioritise investments based on forecast demand growth and constraint timing
- develop district-specific solutions that reflect local demand patterns and network characteristics
- coordinate with territorial authorities on land use planning and infrastructure provision.

Table 2.4 provides a summary comparison of the three districts, highlighting their key characteristics and planning considerations.

Table 2.4 Key planning considerations

	Waimakariri	Hurunui	Kaikōura
Population	• ~70,000 (growing rapidly at 2–3% annually)	• ~13,000 (moderate growth ~1% annually)	• ~4,000 (stable, tourism-dependent)
Network character	• Mixed urban (Rangiora, Kaiapoi) and rural • 90% underground in main towns	• Largely rural with main centres and small towns • Predominantly overhead	• Rural and coastal • Long rural feeders
Major growth areas	• Rangiora (north, west) • Kaiapoi (Mandeville) • Pegasus/Ravenswood • Woodend	• Amberley (urban expansion) • Hanmer Springs (tourism accommodation)	• Limited growth • Focus on supply security and resilience
Key capacity challenges	• Kaiapoi and Southbrook substation capacity constraints • Distribution network reinforcement in growth areas	• Summer peaking from irrigation • Long rural feeder constraints • Amberley zone substation approaching capacity	• Single-contingency supply to Kaikōura • Geographic isolation • Limited backup options
Demand growth drivers	• Residential subdivisions • Commercial development • EV uptake	• Irrigation electrification • Tourism accommodation • Rural residential	• Tourism infrastructure • EV charging (SH1 corridor) • Resilience requirements
Distributed generation	• Growing residential solar (500+ installations) • Commercial solar • Future potential for community-scale batteries	• Kate Valley Landfill (2 MW) • Commercial and residential solar	• Limited current • Potential for tourism facility solar
Demand pattern	• Winter peaking (heating) • EV charging creating evening shoulder peaks	• Summer peaking (irrigation) • Requires targeted load management	• Winter peaking (heating and tourism) • Shoulder peaks from tourism activity
Security standards	• AAA (Rangiora, Kaiapoi urban) • AA (medium town) • A1 (rural)	• AA (Amberley, Hanmer) • A2 (rural and townships)	• AA (Kaikōura township) • A2 (rural)
Investment priorities FY27–FY31	• Zone substation capacity upgrades • Distribution reinforcement • GXP capacity review	• Amberley substation capacity • Irrigation load management • Rural feeder reinforcement	• Supply security enhancement • Resilience improvements

Zone substations are classified for security according to Table 2.12 in section 2.9.2.

Resilience planning for each district is coordinated with the Canterbury CDEM group and local councils as part of our emergency response framework, which is described in section 2.7.

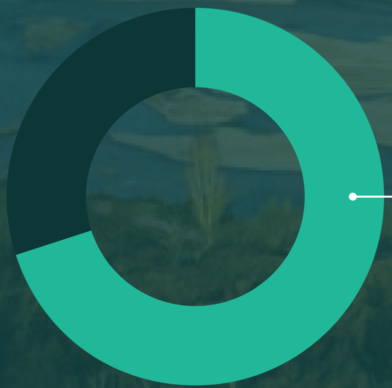
The distinct characteristics of each district drive different investment priorities:

- **Waimakariri district** requires capacity-driven investments to accommodate strong population growth. Our investment programme includes zone substation upgrades, distribution network extensions, and potential GXP capacity augmentation to maintain adequate headroom as demand grows.
- **Hurunui district** requires a combination of capacity upgrades (particularly at Amberley) and demand management solutions to address summer irrigation peaking.
- **Kaikōura district** prioritises supply security and resilience over capacity expansion, reflecting stable demand but high vulnerability to supply interruptions due to geographic isolation, adverse weather, and earthquake risk.

2.5.5 District demand forecasts and capacity analysis

The following sections provide detailed demand forecasts for each district, along with our capacity analysis that identifies where network reinforcement investments are required. These forecasts directly drive the investment programme outlined in section 4.

Kaikōura



70%
of our total customer base

Waimakariri district demand forecast

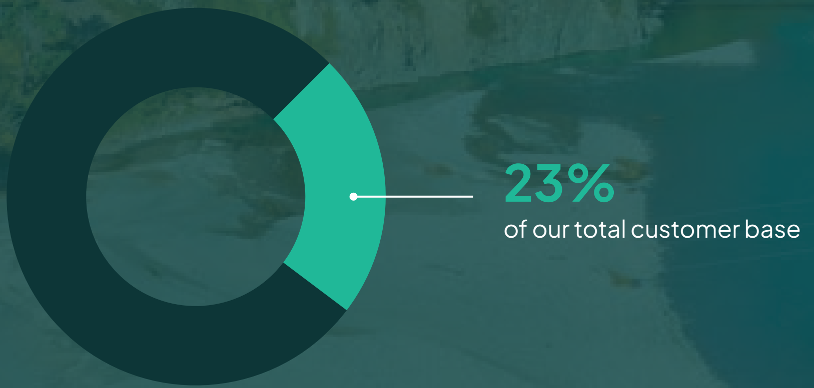
Waimakariri district accounts for approximately 70% of our total customer base and experiences the strongest demand growth across our network. Table 2.5 presents our 10-year demand forecast for key zone substations in Waimakariri, highlighting where forecast demand exceeds current security-class capacity and investment is required.

Table 2.5 Demand forecast for the Waimakariri district

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA)									
			FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ashley 11 kV	A1	40	18.0	18.3	18.4	18.6	18.8	19.0	19.3	19.6	19.8	20.1
Burnt Hill	A1	23	15.4	15.6	15.9	16.2	16.5	16.8	17.1	17.4	17.8	18.1
Kaiapoi 11 kV	AAA	38	29.4	30.7	27.9*	29.0	30.0	31.1	32.3	33.5	34.8	36.0
Southbrook	AAA	40	40.7	42.3	36.3*	37.2	38.0	36.3	37.1	38.0	36.6	37.5
Swannanoa	A1	23	17.4	17.7	18.0	18.3	18.6	18.9	19.2	19.6	20.0	20.3

Note *Dark shading indicates peak demand forecast to exceed current security-class capacity, triggering investment requirement.*

** Decreased due to load transfer to the newly constructed Coldstream zone substation.*



Hurunui district demand forecast

Hurunui district experiences moderate demand growth with distinct summer peaking driven by irrigation loads. Table 2.6 presents our 10-year demand forecast for key zone substations in Hurunui.

Table 2.6 Demand forecast for the Hurunui district

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA)									
			FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Amberley	AA	6..0	6.2	6.5	6.8	7.2	7.5	7.8	8.2	8.5	8.9	9.2
Mackenzies Road	A1	4.0	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6
Greta	A1	4.0	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9
Cheviot	A1	4.0	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9	4.0	4.0
Leader	A1	4..0	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9
Hawarden	A1	4.0	3.9	4.0	4..0	4..0	4.0	4.0	4.1	4.1	4.1	4.2
Mouse Point	AA	13.0	18.0	18.3	18.4	18.7	18.9	19.0	19.2	19.3	19.5	19.6
Marble Point	A2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lochiel	A2	0.5	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Hanmer	AA	2.5	5.1	5.2	5.4	5.6	5.8	6.0	6.2	6.4	6.7	6.9

Note *Dark shading indicates peak demand forecast to exceed current security-class capacity, triggering investment requirement.*

Kaikōura district demand forecast

Kaikōura district shows stable demand, as outlined in Table 2.7, with resilience and security of supply as primary planning drivers rather than capacity growth.

Table 2.7 Demand forecast for the Kaikōura district

Substation	Security class	Class capacity (MVA)	Demand forecast (MVA)									
			FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ludstone	AA	6..0	6.3	6.7	7.0	7.4	7.8	8.2	8.6	9.1	9.5	9.8
Oaro	A1	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Note — *Dark shading indicates peak demand forecast to exceed current security-class capacity, triggering investment requirement.*

Planning for Kaikōura focuses on supply security enhancement rather than capacity expansion, with investments targeting resilience improvements and backup supply arrangements.

These capacity assessments link directly to the investment priorities presented in section 4 and the asset lifecycle strategies in section 3, to make sure that the investment decisions are data-driven and risk-informed.

2.5.6 Linking demand forecasts to investment decisions

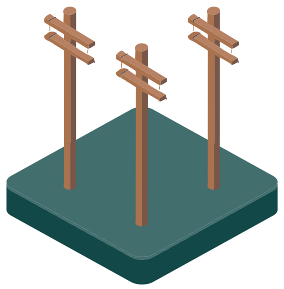
The demand forecasts and capacity analysis presented above directly drive our investment programme.

Capacity-driven investments are triggered where forecast demand exceeds security-class capacity within the planning horizon. The timing and scale of these investments is determined by:

- forecast demand exceedance date (earlier exceedance = higher priority)
- customer numbers affected by potential capacity constraint
- security standard applicable to the area (AA, A1, N-1)
- lead time required for design, consenting, and construction.

Growth-driven distribution investments are required where new subdivisions and developments exceed the capacity of existing distribution feeders. These investments are:

- largely customer-funded through capital contributions for new connections
- planned in coordination with territorial authority infrastructure planning
- incorporated into our annual works programme as developments progress.



Asset replacement and refurbishment investments are also informed by demand forecasts. Where demand is stable or declining, we may defer capacity upgrades and focus on like-for-like replacement. Where demand is growing, replacements incorporate capacity upgrades to avoid premature obsolescence.

These investment decisions are developed using the structured planning and prioritisation framework described in section 4.7 and are supported by the resilience and risk considerations discussed in section 2.2.

2.5.7 Voltage quality and low-voltage network monitoring

Maintaining good voltage quality is fundamental to delivering reliable electricity service. When voltage varies too much, too high or too low, it can damage appliances, disrupt industrial processes, and cause customer complaints. We monitor voltage across our network to identify problems early and maintain the quality of supply our customers expect.

Voltage quality standards

Electricity standards establish acceptable voltage ranges at customer connection points. For most customers receiving electricity at low voltage (400 V or 230 V), the voltage should remain within specific limits. Table 2.8 shows the voltage quality standards for low voltage customers.

Table 2.8 Voltage quality standards for low-voltage customers

Customer type	Nominal voltage	Acceptable range
Residential and small commercial	230 V	207 V to 253 V (+/-10%)

Voltage problems typically fall into two categories:

- **Voltage that is too low** is often caused by long rural power lines, high electricity demand, or undersized infrastructure. Customers may experience dim lights or appliances not working properly.
- **Voltage that is too high** can result from light loading on the network, incorrect transformer tap settings, or distributed generation. Voltage that is too high can damage sensitive equipment.

Voltage monitoring programme

We employ multiple methods to monitor voltage quality across our network:

- **Distribution transformer monitoring:** We have installed monitoring equipment on distribution transformers throughout our network. These monitors continuously record voltage levels and identify when readings fall outside acceptable ranges. This equipment allows us to detect voltage quality issues before customers experience problems or complaints.
- **Smart meter data:** Smart meters installed at customer properties provide half-hourly voltage readings. We analyse this data to identify properties experiencing voltage quality issues. This granular data helps us pinpoint specific network areas requiring attention.
- **Customer complaints and field investigations:** When customers report voltage-related issues, lights flickering, appliances malfunctioning, or equipment damage, our field teams investigate. We use portable voltage recorders to measure actual conditions at the customer's property and throughout the local network.


Hanmer Springs

Voltage issue resolution

When voltage monitoring identifies problems, we investigate the root cause and implement appropriate solutions. The specific approach depends on the nature and extent of the voltage issue.

Localised solutions

For voltage problems affecting individual properties or small groups of customers, we:

- adjust transformer tap settings to raise or lower output voltage
- upgrade service cables or connections
- install voltage regulators for isolated problem areas
- rebalance loads across transformer phases.

Network reinforcement

For voltage problems affecting larger areas or multiple feeders, we:

- upgrade transformers to higher capacity
- install new distribution substations closer to load centres
- reconductor lines with larger cables to reduce voltage drop
- reconfigure the network to shorten feeder lengths.

These larger projects are prioritised within our capital works programme based on the number of affected customers, severity of voltage issues, and expected improvement from the work.

Low-voltage network monitoring

The low-voltage network – the power lines and cables between distribution transformers and customer properties – is experiencing significant change. Growth in rooftop solar generation, EV charging, and battery storage is altering how electricity flows through this part of the network.

Traditionally, electricity flowed in one direction: from our network into homes and businesses. With distributed generation becoming more common, electricity sometimes flows backwards, from customer properties into the network. This bidirectional flow can cause voltage fluctuations and create technical challenges if not properly managed.

We have started a programme to improve our visibility of the low-voltage network. This includes:

- analysing smart meter data to understand load patterns and identify constraints
- installing low-voltage network monitoring equipment at strategic locations
- mapping distributed generation connections and their impact on local networks
- developing thermal and voltage constraint maps to guide connection decisions.

Better visibility of the low-voltage network enables us to identify capacity constraints before they cause problems, plan network upgrades more effectively, and support the transition to more distributed and renewable generation. These initiatives complement our broader monitoring and resilience strategies (outlined in section 2.2) and help us identify issues before they affect customers.

2.5.8 Customer communications and service

Clear and timely communication with our customers is essential, particularly during power outages. We have established processes to keep you informed when planned or unplanned interruptions occur, and to respond to your enquiries and concerns promptly.

Planned outage communications

When we need to interrupt supply for maintenance or network improvements, we follow a structured notification process to minimise inconvenience and allow you to plan accordingly. Table 2.9 summarises the timing and communication methods we use for planned outages.

Table 2.9 Planned outage notification process

Timing	Communication method	Who receives
11 business days before outage	Electronic notification via EIEP5A format to energy retailers	All energy retailers with customers in affected area
48–72 hours before outage (short notice)	Direct SMS or phone contact where possible	Customers in affected area
Day before outage	SMS reminder (where contact details available)	Customers in affected area
During outage	SMS update with revised restoration time	Customers in affected area

The EIEP5A notification format is an industry standard that allows your energy retailer to see planned interruptions on our network. Your retailer may contact you directly based on this information, depending on their customer communication practices.

For work requiring short notice (less than 11 days), we aim to provide at least 48 hours advance warning and make direct contact with affected customers where possible. Emergency maintenance requiring immediate action may proceed with less notice, in which case we treat it as an unplanned outage for communication purposes.

Unplanned outage communications

When unplanned outages occur, due to equipment failure, weather events, vehicle accidents, or other causes, we activate multiple communication channels to keep you informed:

Website outage map:
Our interactive map at www.mainpower.co.nz shows current outages, affected areas, estimated restoration times, and outage causes.

SMS alerts:
Customers who have registered their mobile number receive automatic SMS notifications when outages begin and when power is restored.

Social media:
We post updates on Facebook and other platforms during significant outage events.

Media release:
For widespread outages affecting multiple communities, we issue media statements to local radio stations and news outlets.

Direct contact:
For extended outages or customers with special circumstances, our team makes direct phone contact to provide updates and support.

2.5.9 Supporting our vulnerable customers

We maintain a register of customers who may be particularly vulnerable during power outages, such as those with medical dependencies on electricity supply. This information is provided to us via electricity retailers.
These customers receive priority communication and support, including:

- advance notification of planned outages with direct contact where possible
- priority restoration during extended unplanned outages
- welfare checks during significant weather events or widespread outages
- information about backup power options and emergency preparedness.

If you or someone in your household has medical equipment that requires mains electricity, or if you have other circumstances that make you vulnerable during outages, please contact your electricity retailer (the organisation you receive your power bill from) to ensure your medically dependent status and contact details are up to date.

We keep a register of customers who may need extra support during power outages, including those who rely on electricity for medical or essential needs. These customers receive priority communication and assistance to help keep them safe and informed.

We provide advance notice of planned outages, contacting customers directly whenever possible, and prioritise power restoration for them during extended unplanned outages. During major weather events or widespread interruptions, our teams also carry out welfare checks and share information about backup power options and how to stay prepared in an emergency.

If you or someone in your household depends on mains-powered medical equipment, or if you have other circumstances that could make outages difficult, please let us know so we can add you to our priority support register.

2.5.10 Customer service practices

Strong communication is central to customer satisfaction. The initiatives in this section build on the engagement commitments described in section 1. Our customer service team handles enquiries, complaints, and connection requests. We aim to provide responsive and helpful service across all contact channels. Table 2.10 outlines the types of enquiries we might receive and our target response times.

Table 2.10 Customer service performance targets

Service type	Target response time
Emergency calls (faults, safety hazards)	Answered within 30 seconds
General enquiries (phone)	Answered within 2 minutes
Email enquiries	Initial response within 1 business day
Written complaints	Acknowledged within 2 business days
Complaint resolution	Resolved within 20 business days

We handle complaints in accordance with our published complaints process and the Consumer Guarantees Act. Customers who are not satisfied with our response can escalate their concern to Utilities Disputes, an independent dispute resolution scheme.

2.6
Building resilience for climate change and natural hazards

Keeping power reliable means preparing for what we cannot control. Storms, floods, earthquakes, and other natural hazards can disrupt electricity supply, damage infrastructure, and isolate communities.

This section explains how we are strengthening our network and operations so that we can continue to deliver safe, reliable power even as our climate and environment change.

2.6.1 Resilience strategy overview

Our resilience strategy recognises that extreme weather and natural hazards are increasing in both frequency and severity. We are acting now to understand the risks, adapt our network, and partner with others to improve community readiness. Resilience for MainPower means withstanding shocks, recovering quickly, and learning from every event.

Key objectives of our strategy are to:

- protect public safety and minimise outage duration during extreme events
- design and maintain infrastructure that performs under changing environmental conditions
- work collaboratively with CDEM groups, councils, and regional lifelines to coordinate emergency response
- invest efficiently, balancing reliability, cost, and long-term sustainability.

Our approach aligns with the National Adaptation Plan (2022), Canterbury Civil Defence Emergency Management Strategy, and the Electricity Engineers' Association Climate Resilience Guidelines.

2.6.2 Our three-stage resilience roadmap

We have developed a staged roadmap to guide investment and action over time. Figure 2.12 illustrates our journey on the resilience path. It reflects what we know today and how we will keep learning and adapting as conditions change.

Stage 1: Learning

Stage 2: Preparation

Stage 3: Adaptation

Stage 1 (years 1–3): Learning and planning

We are building the foundation for long-term resilience by:

- collecting better data on climate exposure, flood plains, and coastal erosion
- partnering with NIWA, Canterbury Lifelines, and CDEM groups to share information
- reviewing design standards for storm, flood, and seismic performance
- mapping critical assets most exposed to flooding or landslip
- engaging with customers and councils to understand local vulnerabilities
- developing a comprehensive Climate Resilience Investment Plan.

Stage 2 (years 4–10): Network preparation and implementation

During this period, we move from planning to delivery, including:

- upgrading poles, conductors, and substations to meet updated design standards
- introducing climate-resilient materials and construction practices
- coordinating renewal works with resilience priorities
- implementing new standards for stormwater protection and site drainage
- updating emergency response and recovery procedures based on scenario testing.

Stage 3 (10 + years): Long-term adaptation

Long-term resilience will require continual adaptation as our understanding of climate impacts evolves.

Key actions include:

- maintaining long-term partnerships with science and emergency agencies
- regularly updating climate modelling and risk maps
- investing in network automation, distributed generation, and flexible systems that can re-route power
- monitoring performance after events to refine future design standards.

Figure 2.12 Our resilience roadmap

2.6.3 Current resilience activities and partnerships

We are already implementing resilience initiatives across our network and operations.

Our current focus areas (FY26–FY28) are:

- completing flood-risk assessments for all substations in low-lying areas
- participating in the Canterbury Lifelines Project to identify shared infrastructure dependencies
- working with Transpower on coordinated restoration scenarios for the national grid interface
- updating emergency response plans in partnership with the Canterbury CDEM Group
- developing a climate adaptation dataset using regional modelling (NIWA, 2025 update)
- strengthening regional coordination with lifeline utilities for rapid response and information sharing.

These partnerships enable shared learning, efficient investment, and faster recovery when events occur. We also contribute technical expertise to regional planning forums to ensure electricity considerations are included in wider emergency and climate strategies.

2.6.4 What this means for you

Our investment in resilience protects customers and communities across North Canterbury. It means:

- fewer and shorter outages during severe weather or natural disasters
- better-prepared communities, with coordinated emergency response plans
- lower long-term costs, because proactive investment prevents more expensive reactive repairs
- stronger regional partnerships that keep critical services running when they are needed most.

By building resilience today, we safeguard your electricity supply and support the long-term sustainability of our region.

2.7
Incident management and emergency response

When major storms, earthquakes, or system failures occur, our priority is to keep people safe and restore electricity as quickly as possible. This section explains how we prepare for, respond to, and recover from significant events. It also describes our legal obligations as a designated Lifeline Utility under the Civil Defence Emergency Management Act 2002.

2.7.1 Business continuity planning

Our Incident Management Plan ensures that essential services continue even when normal operations are disrupted. It identifies critical functions such as network control, field operations, communications, and safety management, and sets out how we maintain them under stress.

Key features of the plan include:

- **critical function mapping –** prioritising what must operate first to keep customers supplied and staff safe
- **alternate control arrangements –** backup network operations centre capability and remote access systems
- **data and IT continuity –** off-site data replication and cybersecurity resilience
- **people and facilities continuity –** clear delegation of authority, emergency contact trees, and site-access plans
- **testing and review –** annual simulation exercises and post-event reviews.

The Incident Management Plan integrates with our risk management framework (section 2.2) and is reviewed every year by the Executive Team and Board Audit and Risk Committee.

2.7.2 Incident management framework – The 5 R's

Our incident response follows New Zealand's Coordinated Incident Management System, ensuring we work seamlessly with emergency agencies. Our incident management is based a framework of reduction, readiness, response, recovery, and review, as shown in Figure 2.13.

The five R's

R – Reduction

Purpose: Identify and minimise potential hazards before they occur.
MainPower focus: Apply risk controls and resilience investments.

R – Readiness

Purpose: Prepare people, systems, and partners for effective response.
MainPower focus: Maintain trained emergency teams, depots stocked with critical materials, and standby generators.

R – Response

Purpose: Act quickly to protect life and restore essential supply.
MainPower focus: Activate the Incident Management Team; coordinate with local CDEM groups; deploy field crews 24/7.

R – Recovery

Purpose: Return to normal operations and support community recovery.
MainPower focus: Prioritise restoration for hospitals, water, and communications; assist councils and lifelines partners.

R – Review

Purpose: Learn from events and strengthen future response.
MainPower focus: Conduct post-incident reviews and update procedures and training.

Figure 2.13 Our incident management framework

Regular training and exercises keep our people confident and coordinated. Two full-scale simulations are run each year, complemented by desktop and field-based drills with partner agencies.

2.7.3 Civil defence emergency management (CDEM) obligations

We are formally designated as a Lifeline Utility under the Civil Defence Emergency Management Act 2002. This designation means we have a legal and moral responsibility to maintain and restore electricity supply during and after emergencies.

Our obligations include:

- operating, to the extent practicable, during emergencies – even at reduced capacity
- maintaining and exercising emergency plans that support the Canterbury CDEM Group Strategy
- participating in regional planning and debriefs to provide technical advice and status updates
- collaborating with other lifeline utilities (telecommunications, water, transport) to coordinate restoration priorities
- providing regular situation reports to the CDEM Controller and the National Emergency Management Agency (NEMA).

We also support the Canterbury Lifelines Project, which maps inter-dependencies between critical infrastructure providers to improve regional resilience.

2.7.4 Response and recovery in practice

When a major incident occurs, our Incident Management Team is activated. This team brings together specialists in operations, logistics, safety, communications, and planning.

During an incident:

1. **Safety first –** Confirm that all staff and the public are safe before restoration begins.
2. **Situation assessment –** Determine scale, locations, and causes of outages.
3. **Prioritisation –** Restore critical community services first (hospitals, water, communications, emergency facilities).
4. **Communication –** Provide timely updates through SMS, website, social media, and CDEM channels.
5. **Deployment –** Field crews and contractors are dispatched from depots in Rangiora, Culverden, and Kaikōura, operating 24/7.
6. **Monitoring –** Provide regular updates to CDEM Controller and internal leadership.

After an incident:

1. Conduct technical inspections before re-energising affected assets.
2. Support community recovery by coordinating with local councils and emergency partners.
3. Complete detailed debriefs and improvement actions.

2.7.5 What this means for you

Our incident management and emergency-response systems mean that, when the unexpected happens, you can rely on us to:

- restore power as quickly and safely as possible
- communicate clearly about what is happening and when power will be back on
- coordinate with emergency services so that critical community needs come first
- learn from every event to improve future readiness.

Through disciplined preparation and collaboration, we keep North Canterbury powered, even when nature tests us the most.

Hanmer Springs

2.8
Contingency planning and insurance

Being ready for the unexpected means having both the resources and the financial protection to recover quickly. This section explains how we plan for rare but high-impact events such as major equipment failure, natural disasters, or supply interruptions, and how our insurance programme supports cost-effective risk management.

2.8.1 Contingency planning for critical assets

Key components:

- Critical-asset register –Single-point-of-failure review –Spare-asset strategy –Emergency logistics plan –Documentation and training –

Critical asset hierarchy

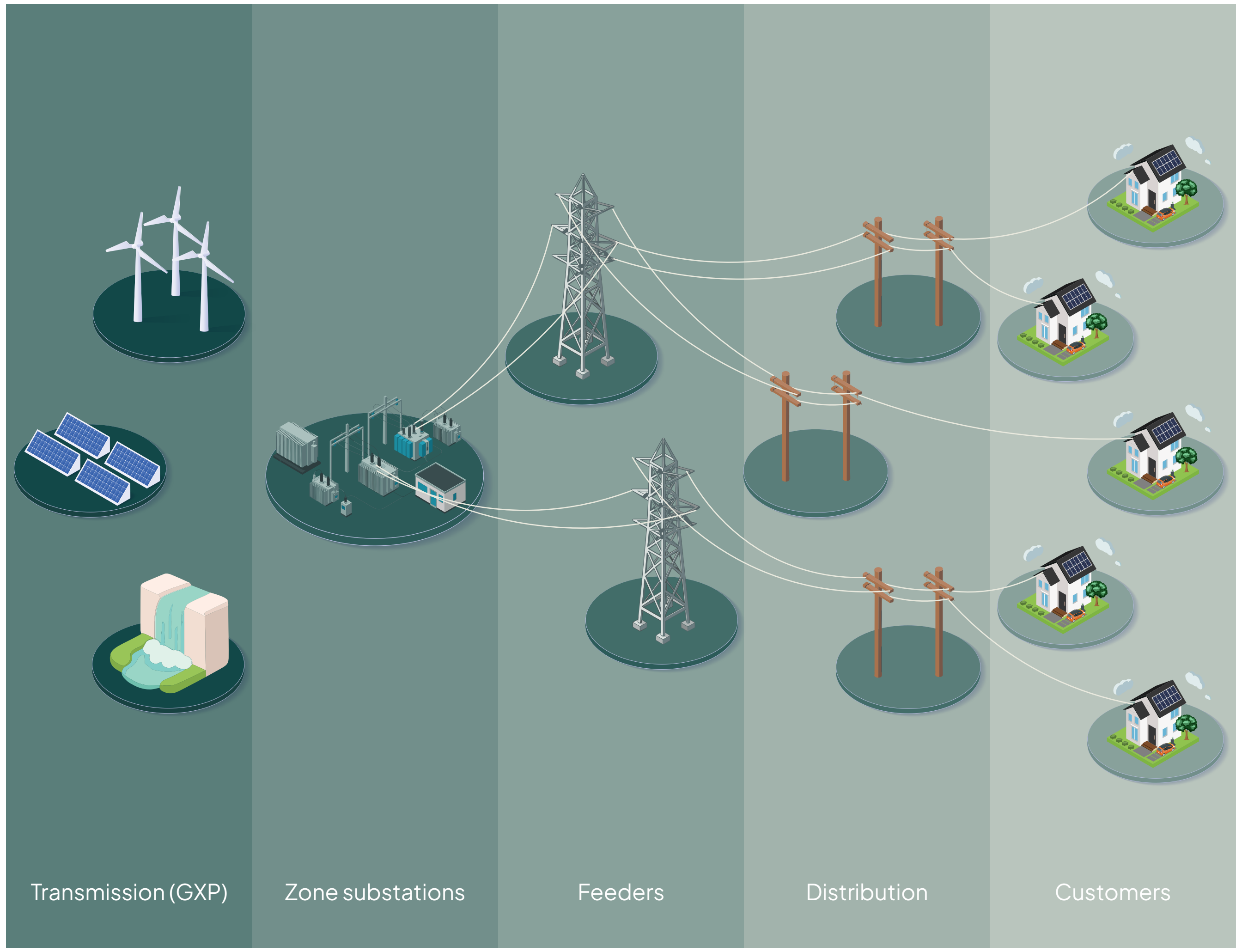


Figure 2.14 Essential elements of the electricity distribution system

2.8.2 Protocols for restoration of service

Our commitment is simple: restore power as safely and quickly as possible. Clear restoration protocols guide decision-making during unplanned outages. Figure 2.15 show the workflow we follow to effectively and efficiently make repairs.

Restoration principles

1. **Safety first –** Confirm that sites are safe and de-energised before work begins.
2. **Priority to critical services –** Hospitals, water, communications, and CDEM facilities are restored first.
3. **Urban before rural only where justified –** Prioritisation is based on customer numbers, community impact, and accessibility.
4. **24/7 crew deployment –** Field teams and contractors are on rotating shifts with remote support from the Network Operations Centre.
5. **Customer communication –** Provide real-time updates through website, SMS, and social media; coordinate with councils for vulnerable-customer information.
6. **Post-restoration review –** Confirm integrity of repaired assets and record data for improvement.

Our depots and mobile generation units give us the flexibility to isolate damaged sections and re-energise unaffected areas quickly. Average restoration times are benchmarked against national peers and reported in annual information disclosures.

Restoration workflow

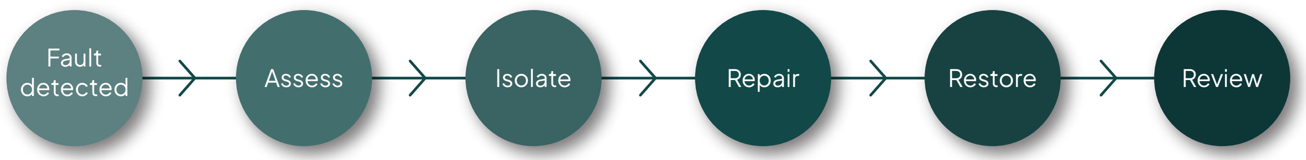


Figure 2.15 Restoration workflow

2.8.3 Our insurance programme

Insurance provides financial resilience by reducing the cost impact of rare, high-value losses. Our programme is reviewed annually to ensure the right balance between cover, premium, and self-insurance.

Scope of cover

- **Public liability –** injury or damage claims arising from network operation
- **Material damage –** substations, control buildings, and major plant
- **Contract works –** construction risks during major projects
- **Motor fleet and mobile plant –** vehicles and heavy equipment
- **Cyber security cover –** response costs for data or system breaches

Because it is not cost-effective for us to insure the entire distribution network, we maintain a self-insurance fund for overhead and underground assets. The fund's adequacy is reviewed each year using actuarial analysis and benchmarking against comparable distributors. Our insurance and self-insurance arrangements complement the preventive measures and contingency plans described in this section, forming a complete financial-risk-management system.

2.8.4 What this means for you

Our contingency and insurance arrangements mean that when significant events occur, you can be confident that:

- power will be restored as quickly and safely as conditions allow
- critical community services will receive immediate attention
- costs from major damage are managed responsibly, protecting long-term affordability
- lessons from each event feed back into better planning and resilience.

By combining robust contingency planning with sound financial protection, we deliver reliability and value no matter what challenges arise.

Hanmer Springs

Figure 2.16
Subtransmission network map showing GXPs supplying MainPower's network, and Transpower 220 kV and 66 kV transmission lines

2.9 Network configuration

Our network connects communities across North Canterbury to the national grid, delivering safe and reliable electricity to more than 46,000 homes and businesses. This section explains how the system is configured, how it operates day-to-day, and how its design supports the performance and resilience outcomes described earlier in this plan. Figure 2.16 shows the GXPs supplying MainPower's network, and Transpower's 220 kV and 66 kV transmission lines.

46,000

Homes and businesses

Figure 2.17 Subtransmission network map showing GXPs, zone substations, 66 kV and 33 kV subtransmission lines

2.9.1 How the network is structured

Our electricity distribution network is supplied through five key connection points called grid exit points (GXPs). These GXPs link us to the national grid, which is owned and operated by Transpower. The GXPs connect to major transmission lines operating at very high voltages (220,000 V and 66,000 V), coming from Islington substation in Christchurch.

Think of GXPs as the main taps where we receive electricity from the national network. From these points, we transform the electricity down to lower voltages suitable for distribution to homes and businesses throughout North Canterbury.

Table 2.11 provides details about each of the five GXPs, showing their capacity and what they supply.

Table 2.11 Grid exit points into our network

Grid exit point	Total capacity	Firm capacity	Current peak demand	Configuration	What it supplies
Kaiapoi	76 MVA	38 MVA	29.5 MW	Two 38 MVA 66/11 kV three-phase transformers	Rangiora and Kaiapoi urban areas via eight 11 kV circuit breakers
Southbrook 66 kV	Switching station (no transformers)	N/A – passes 66 kV through	N/A	66 kV switching station	Southbrook, Swannanoa, and Burnt Hill areas via four 66 kV circuit breakers
Ashley (ASY011)	80 MVA	40 MVA	14.5 MW	Two dual-rated 40 MVA 66/11 kV three-phase transformers	Rural areas (five 11 kV circuits) and Daiken manufacturing plant (four 11 kV circuits)
Waipara (WPR0331 and 0661)	160 MVA	80 MVA to 66 kV bus	16.7 MW (66 kV), 8.1 MW (33 kV)	Two 80 MVA 220/66 kV transformers; one 66/33 kV 10/16 MVA transformer	Waipara and Amberley areas via two 33 kV feeders, one 66 kV feeder, one 66 kV load plant circuit
Culverden (CUL0331 and 0661)	60 MVA	30 MVA to 33 kV bus	24.6 MW	Two 30 MVA 220/33 kV transformers; One 10/20 MVA 33/66 kV transformer (13.09 MVA)	Culverden, Cheviot, Kaikōura, and Hanmer Springs via two 33 kV feeders and one 66 kV feeder

Note *MVA (megavolt-amperes) and MW (megawatts) are measures of electrical capacity. One MVA is roughly equivalent to enough power for 650–750 average homes. Firm capacity represents the capacity available with one transformer out of service (N-1 contingency).*

From these GXPs, electricity is transformed from 66 kV or 33 kV down to 11 kV at our zone substations, then distributed through overhead and underground feeders to local transformers that supply low-voltage networks.

The network consists of approximately 5,800 km of lines and cables, including:

- 33 kV subtransmission lines linking GXPs to major load centres
- 11 kV distribution feeders serving urban and rural areas
- low-voltage (400/230 V) networks supplying individual customers.

We operate three depots – in Rangiora, Culverden, and Kaikōura – which provide 24/7 response capability across the region.

These network configurations, combined with the security standards outlined below, form the foundation for the reliable and resilient supply our customers experience every day.

2.9.2 Security of supply standards

We design and operate our network to meet security of supply standards that reflect the importance of electricity supply to different customers and areas. These standards guide how much redundancy (backup capacity) we build into different parts of the network.

Table 2.12 explains the security classifications we use and what they mean for different customer types. These standards balance the cost of providing backup capacity against the consequences of supply interruptions.

Table 2.12 Security of supply classifications

Substation class	Substation load type	Targeted duration for first transformer, line, or cable fault	Targeted duration for bus or switchgear fault
AAA	Urban or industrial load > 10 MW peak or 30 GWh annual consumption	No interruption	No interruption for 50% and restore the rest within 2 hours
AA	Urban load > 2 MW peak or 6 GWh annual consumption	45 minutes	Restore 75% within 2 hours
A1	Predominantly rural and semi-rural loads totalling > 1 MW	Isolation time	Repair time
A2	Predominantly rural and semi-rural loads totalling < 1 MW	Repair time	Repair time

Note *Zone substation classification descriptions:*

AAA *Supply is uninterrupted in the event of the outage of one major element of the subtransmission network. Load can be transferred to other substations without interruption by switching on the network, if necessary, to avoid exceeding ratings.*

AA *Supply may be lost in the event of the outage of one major element of the subtransmission network. Supply can be restored within 45 minutes by switching at the subtransmission or distribution level.*

A1 *Supply may be lost in the event of the outage of one major element of the subtransmission network. Supply can be restored by switching after the faulted element is isolated.*

A2 *Supply may be lost in the event of the outage of one major element of the subtransmission network. Supply cannot be restored until the faulty element is repaired or replaced.*

Urban areas with higher customer density justify higher security standards (AA or A1), while remote rural areas with few customers typically have basic security (N or A2) with manual backup arrangements. These design standards work hand-in-hand with our wider risk and resilience measures (described in section 2.2), ensuring that the level of redundancy and backup capacity is proportionate to community needs and risk exposure.

2.9.3 Network operation and control

The network is operated from our Network Operations Centre in Rangiora, which monitors system performance 24 hours a day. Operators use an advanced distribution management system (ADMS) integrated with geographic information system (GIS) data and remote field devices.

Key features include:

- real-time visibility of voltage, load, and fault conditions
- remote control and automatic re-closing on major feeders
- predictive analytics to identify emerging faults before they affect customers
- live interface with customer-notification systems and outage maps.

These tools allow faster fault isolation, shorter restoration times, and improved safety for field crews and the public.

2.9.4 Maintenance and operational practices

Operational performance depends on disciplined maintenance and inspection. We follow a risk-based maintenance regime, targeting assets that have the greatest impact on reliability or safety.

Typical activities include:

- routine inspections of substations, poles, and conductors using both ground and aerial methods
- thermal imaging and partial-discharge testing for condition assessment
- preventive vegetation management around overhead lines
- scheduled equipment servicing to manufacturer and industry standards
- live-line maintenance where appropriate to reduce customer outages.

Maintenance strategies are guided by condition-based risk management and informed by reliability performance.

2.9.5 Integration with contingency and restoration planning

The operational configuration of the network directly supports our contingency planning (section 2.8). Automatic switching points and sectionalising devices allow crews to isolate faults and re-energise unaffected areas quickly. Mobile generation and spare transformers are pre-positioned to support remote zones or single-feed communities.

These operational design features help keep average outage durations among the lowest in the South Island and ensure compliance with Commerce Commission reliability standards.

2.9.6 Future network development

We continue to adapt our network to meet changing technology and customer needs. Planned enhancements include:

- additional automation and fault-location devices on rural feeders
- an upgraded communications backbone to support distributed energy resources
- integration of low-voltage monitoring from smart meters into ADMS analytics
- expansion of load-forecasting tools to capture electrification trends (EVs, heating)
- progressive undergrounding in high-growth areas.

These developments align with the network development plan (section 4) and support the resilience and adaptation goals outlined in section 2.6.

2.9.7 What this means for you

The configuration and operation of our network are what make reliability possible every day. For customers, this means:

- a robust system designed to handle growth and environmental challenges
- faster fault detection and restoration through automation
- efficient investment focused where it delivers greatest customer value
- a safer, smarter network ready for future technologies.

By designing and operating a modern, flexible network, we keep power reliable today while preparing for the needs of tomorrow.

2.10
Customer interface and service linkages

Our technical systems, maintenance practices, and contingency planning and service outcomes are all designed with customers in mind.

We continue to strengthen the link between our operational capability and customer experience by:

- integrating outage management and customer-notification systems
- aligning connection standards with customer feedback
- using performance data from section 1 to guide investment and process improvement
- coordinating service communications with local CDEM groups and councils during major events.

By connecting our operational performance to customer experience, we make sure every technical improvement **delivers real value for our communities.**

Rangiora

2.11 Non-network solutions and distributed energy resources

As electricity demand patterns change and new technologies emerge, we increasingly look beyond traditional network reinforcement to meet customer needs. Non-network solutions and distributed energy resources offer alternatives that can defer or avoid costly infrastructure investments while supporting the energy transition.

2.11.1 What non-network solutions mean for our customers

Non-network solutions use smart technologies or market mechanisms instead of physical network upgrades to manage demand and maintain supply quality. For customers, this means:

- **fewer costly upgrades –** using flexibility rather than new lines keeps bills fair
- **faster solutions –** many non-network options can be deployed quickly
- **greater choice –** customers can participate through solar panels, batteries, or flexible loads
- **lower emissions –** by supporting distributed generation and efficient energy use.

2.11.2 Our approach to non-network alternatives

We assess non-network solutions alongside traditional network reinforcement at every stage of planning.

The process includes:

1. **identification –** screening areas of the network approaching capacity or reliability limits
2. **option evaluation –** comparing network and non-network options through cost-benefit analysis and risk assessment
3. **engagement –** working with customers, developers, and service providers to test interest and technical feasibility
4. **implementation –** trialling or adopting the best-value solution.

Examples of non-network options considered include demand response programmes, local generation, distributed batteries, and power-factor correction at customer sites.

Hanmer Springs

2.11.3 Supporting distributed energy resources

Customer-owned generation and storage are growing rapidly across North Canterbury. We are adapting our systems and standards to integrate these safely and efficiently.

Key actions include:

- streamlined connection standards for small-scale solar and battery systems
- advanced protection and control settings to maintain voltage stability with two-way power flow (Figure 2.18)
- low-voltage monitoring through smart meters and ADMS integration
- data sharing with aggregators and retailers (where consented) to enable flexibility services
- hosting-capacity studies to identify where further distributed energy resources growth can be accommodated.

We also participate in national working groups led by the Electricity Engineers' Association and Electricity Authority to shape consistent technical and market frameworks for distributed energy resources.

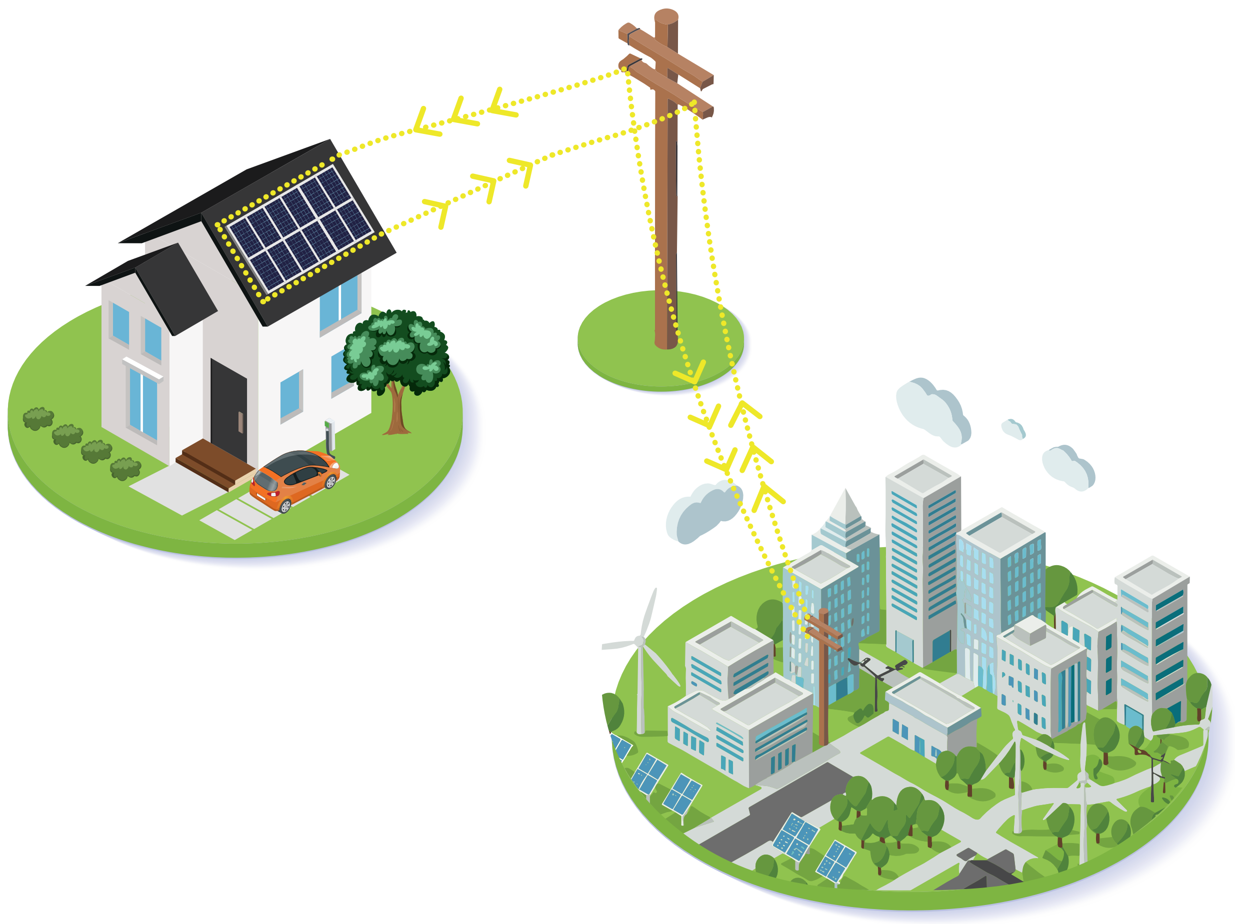


Figure 2.18 Bi-directional power flow

2.11.4 Future direction

Over the next decade, we expect the proportion of non-network investment to increase as technology costs fall and customers become more active participants. Our planning framework ensures each solution – network or non-network – is chosen on the basis of value for customers, reliability outcomes, and environmental benefit.

Hanmer Springs

3
Managing our assets

Our assets are the backbone of the electricity network that powers North Canterbury. This section explains how we manage them through every stage of their life, from installation and maintenance to renewal and disposal, so we can keep power reliable, affordable, and safe for our communities.

From planning to performance

Figure 3.1 Lifecycle asset management

3.1 Managing the asset lifecycle

Delivering value means making the right decisions about when to maintain, refurbish, or replace each asset. We apply a structured lifecycle approach that balances network performance, safety, and cost.

3.1.1 Lifecycle management philosophy

Condition based – assets are replaced when their condition or risk justifies it, not simply because of age.

Whole-of-life thinking – from design to construction, operation, maintenance, refurbishment, and decommissioning, to find the optimum long-term cost.

Performance measurement – reliability indices (SAIDI, SAIFI) and asset-health models confirm that decisions deliver the intended outcomes.

Environmental responsibility – materials are recycled or reused wherever possible.

Risk-based prioritisation – condition-based risk management and the As Low As Reasonably Practicable (ALARP) principle guide our investment choices.

Lifecycle reviews are updated annually and feed into our long-term network plans in section 4.

We use a condition-based approach to help us plan replacements. Our framework follows Electricity Engineers' Association guidance and draws on inspection results, performance history, and deterioration trends to forecast the likelihood of failure. We are continually working on improving our risk analytics capability to better target our high-risk assets and to make good investment decisions.

3.2 Overhead line assets

Our electricity network stretches across towns, rural areas, and farms, with around 57,000 poles carrying more than 4,000 km of overhead lines, plus about 1,200 km of underground cables, giving a total network length of roughly 5,260 km. Figure 3.2 below shows the extent of our distribution network.

Figure 3.2 Our distribution network

Total network length 5,260 km

3.2.1 Poles and pole hardware

Over the years, we have used different materials for poles. From hardwood and creosote-treated larch in the early days, to treated pine and concrete from the 1960s onwards. Today, new poles are made from H5-treated radiata pine or pre-stressed concrete, designed to last up to 80 years. Older reinforced concrete poles from the 1960s to 1980s are being gradually replaced as part of our renewal programme.

We use a mix of inspection methods – including aerial surveys, high-resolution cameras, and light detection and ranging (LiDAR) scanning – to check pole condition, clearance distances, and resilience. This digital data feeds into our planning systems so we can identify and address risks early.

Replacement and disposal

MainPower's pole replacement programme uses condition assessment data and a range of other information about poles to create a risk-based replacement priority list. Figure 3.3 outlines the asset health indicator scale used on the following pages.

Condition	Asset health score	Definition
Poor	H1	Replacement recommended
	H2	End-of-life drivers for replacement recommended, high asset-related risk
Fair	H3	End-of-life drivers for replacement recommended, increasing asset-related risk
Good	H4	Asset serviceable – no drivers for replacement, normal in-service deterioration
	H5	As-new condition – no drivers for replacement

Figure 3.3 Asset health indicator scale

When poles need replacing, we prioritise them based on condition, safety, and performance, not just age. Where possible, we coordinate pole replacements with line upgrades or resilience improvements to make the most of planned work and reduce disruption for customers. Figure 3.4 outlines our pole fleet health and risk scenarios.

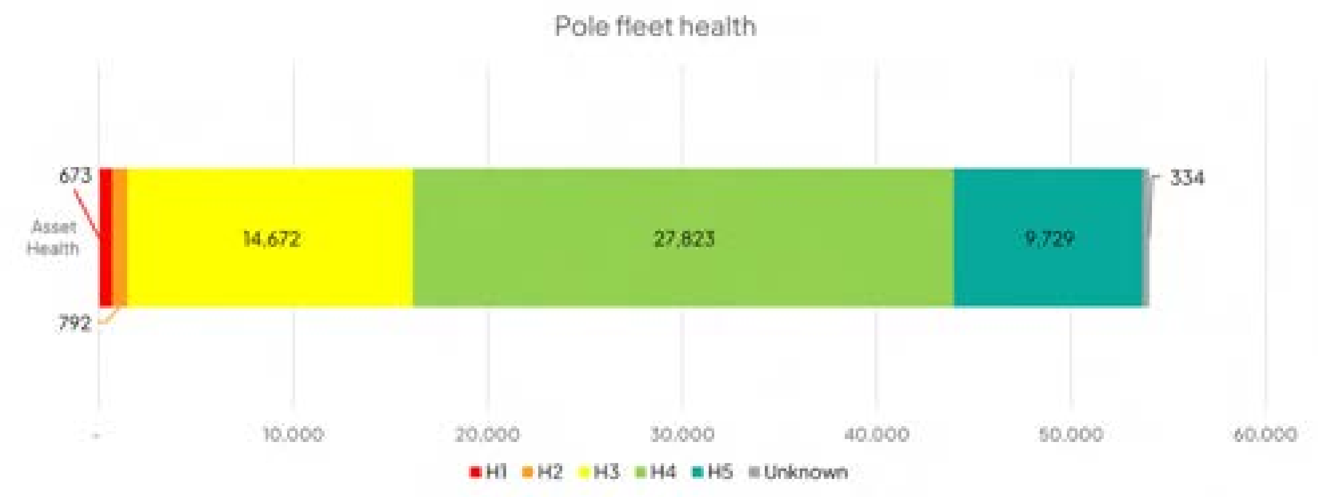


Figure 3.4 Pole fleet health (FY25)

3.2.2 Crossarms and insulators

Pole-top assemblies include crossarms, insulators, fuses, and surge arrestors that keep power flowing safely. Crossarms are made mainly from hardwood or galvanised steel, while insulators use porcelain, glass, or modern polymer materials. Components are replaced when inspections show deterioration, and wherever possible, work is combined with pole replacement to limit outages.

3.2.3 Conductors

The conductors (wires) that carry electricity through our network are selected based on the environment and performance requirements for each area. Most of our network uses modern aluminium conductors, but some older rural lines still include legacy copper conductors with ageing insulation.

We currently have a targeted replacement programme for these older sections, and we are developing a new condition-based model that uses data to better understand conductor health and performance. This will help us plan future replacements more accurately and efficiently.

3.3
Switchgear assets

Switchgear protects and controls the flow of electricity, allowing sections of the network to be isolated safely during faults or maintenance.

3.3.1
Circuit breakers

Circuit breakers play a vital role in our electricity network by safely stopping the flow of electricity whenever it is needed, such as during faults or maintenance. Many of the older circuit breakers used oil to perform this task. Over time, we have been replacing these with newer models that use gas or a vacuum instead. These modern circuit breakers help us to meet today's safety and environmental standards while keeping our network reliable and cost-effective for everyone.

Some of our high-voltage circuit breakers contain a gas called sulphur hexafluoride (SF_6), which is an effective insulating material, but it is also a powerful greenhouse gas. Because of this, we follow strict, specialised procedures to handle SF_6 safely and protect the environment.

Since 1995, most circuit breakers we have installed can be operated remotely. This means we can respond more quickly to power interruptions and maintain a safer, more reliable electricity supply for our community.

To plan for the long term and ensure our circuit breakers remain in good condition, we are developing a model that assesses the assets on condition and risk. This will help us prioritise replacement work and manage our risk. You can see the current health of our circuit breakers in Figure 3.5 below.

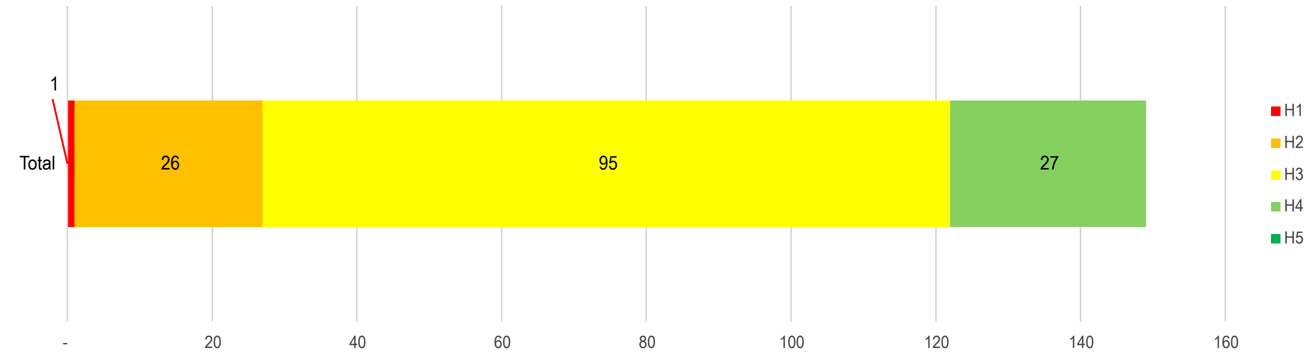


Figure 3.5 Asset health of our circuit breakers (FY25)

3.3.2
Reclosers, sectionalisers, and load break switches

These devices are installed strategically along distribution feeders to protect the network. Most units use vacuum or SF_6 insulation, although a small number of older oil-insulated units remain. We prioritise replacements based on condition, criticality, and performance. Older oil-filled models, such as certain Nulec and GVR types, are being phased out.

Oil is safely drained and recycled through certified recyclers, vacuum units are recycled, and SF_6 gas is recovered by approved contractors to prevent emissions.

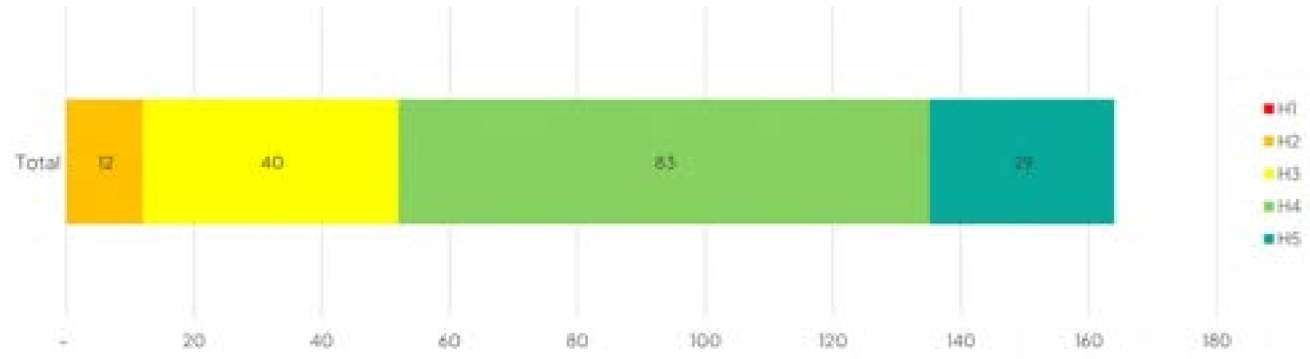


Figure 3.6 Asset health of our reclosers, sectionalisers, and load break switches (FY25)

3.3.3 Ring main units

Ring main units connect and protect key parts of the network. Earlier units used cast-resin or oil insulation (1960s to early 2000s), while modern units use vacuum or SF_6 insulation. Older oil-filled ring main units are nearing the end of their lives, with higher failure rates and maintenance costs. Replacement decisions consider condition, age, and parts availability. Oil-filled units are disposed of responsibly, and reusable parts are refurbished where possible.

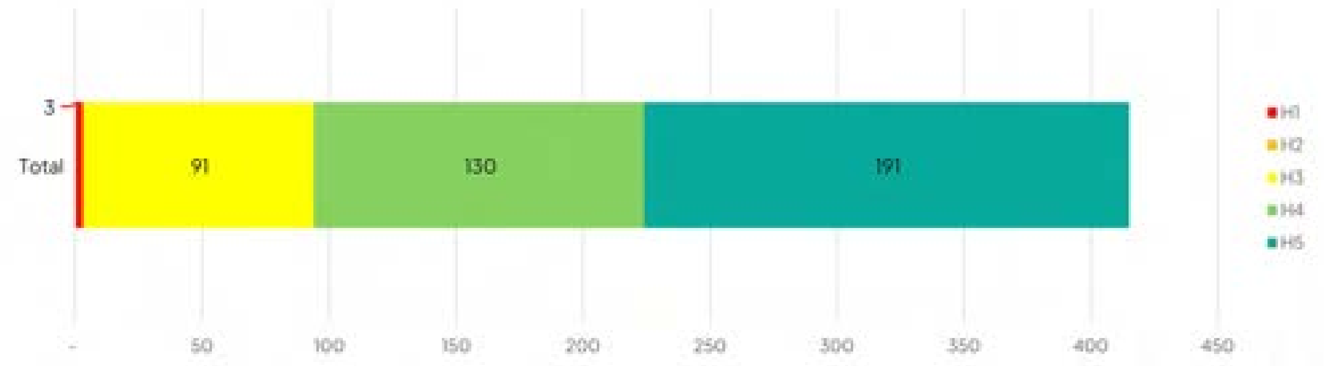


Figure 3.7 Asset health of our ring main units (FY25)

3.3.4 Air break switches

Air break switches operate at 11–66 kV and are used to isolate or reconfigure parts of the network. Our fleet includes models from Canterbury Engineering (1950s–1980s), Dulmison, Electropar, ABB, and Allied. Regular inspections and modelling determine when replacement is needed. Older Canterbury Engineering units are being replaced, and some sites are being upgraded to automated load break switches or reclosers for improved reliability.

Figure 3.8 Asset health of our air break switches (FY25)

3.3.5 Low-voltage switchgear

We operate around 600 low-voltage switchgear units, usually in ground-mounted kiosks near distribution transformers. The main types are ABB Fastline (SLK) and modern DIN-style fused switches supplied by Jean Muller, Weber, and Efen. Known issues with low-voltage switchgear are outlined in Table 3.1.

Table 3.1 Low-voltage switchgear known issues

Switchgear type	Known issues/defects
Exposed (skeleton) panels	• Porcelain fuse handles may cause localised heating • Exposed bus-work
D & S fused switches	• Risk of incomplete switching
Terasaki circuit breakers	• Risk of incomplete switching
ABB Fastline (SLK)	• Localised heating from poor cable terminations
DIN-style fused switches	• Localised heating from poor cable or fuse terminations

Low-voltage switchgear identified with safety or reliability concerns is replaced, often in conjunction with ring main unit or transformer maintenance to reduce outages and costs.

3.4 Transformer assets

Transformers convert electricity to the correct voltage for transmission and supply. Table 3.2 outlines the range of our transformer fleet.

Table 3.2 Transformer fleet overview (FY25)

Transformer type	Quantity
Power transformers	24
Distribution transformers	8,542
Voltage regulators	26

3.4.1 Power transformers

Zone substation power transformers (4–40 MVA) step down transmission voltages to 11 kV, 22 kV, or 400 V. Nine spare units are maintained for emergency response. The typical design life is about 45 years, although actual life depends on operating conditions. Figure 3.9 shows the age profile of our transformer fleet, while Figure 3.10 indicates the health of these assets.

Monitoring includes quarterly checks, annual dissolved-gas analysis, and five-yearly major services. Health assessments indicate that four older units (50–59 years) may need replacement within 10 years, with one additional unit (40–49 years) under close observation. When replacements occur, usable parts are recovered, oil is safely drained, and materials are recycled.

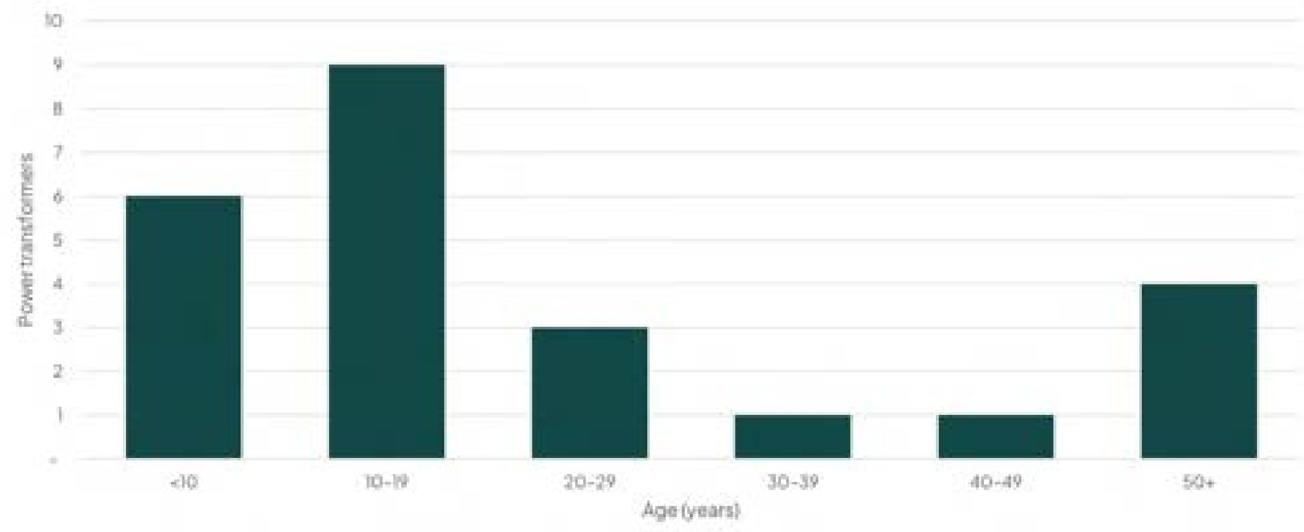


Figure 3.9 Age profile of our power transformers (FY25)

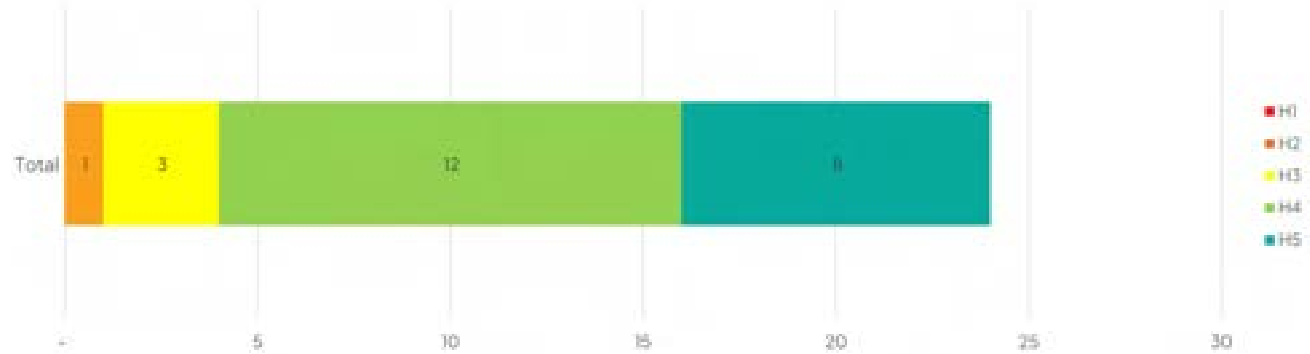


Figure 3.10 Asset health of our power transformers (FY25)

3.4.2 Distribution transformers

We operate more than 8,500 distribution transformers; about 85% are pole-mounted and the remainder are ground-mounted. They convert electricity to 230 V (single-phase) or 400 V (three-phase). Units are replaced when oil leaks, corrosion, or internal faults are identified. Faulty units are drained and sent to approved recyclers, and oil is stored safely until processed by certified waste handlers.

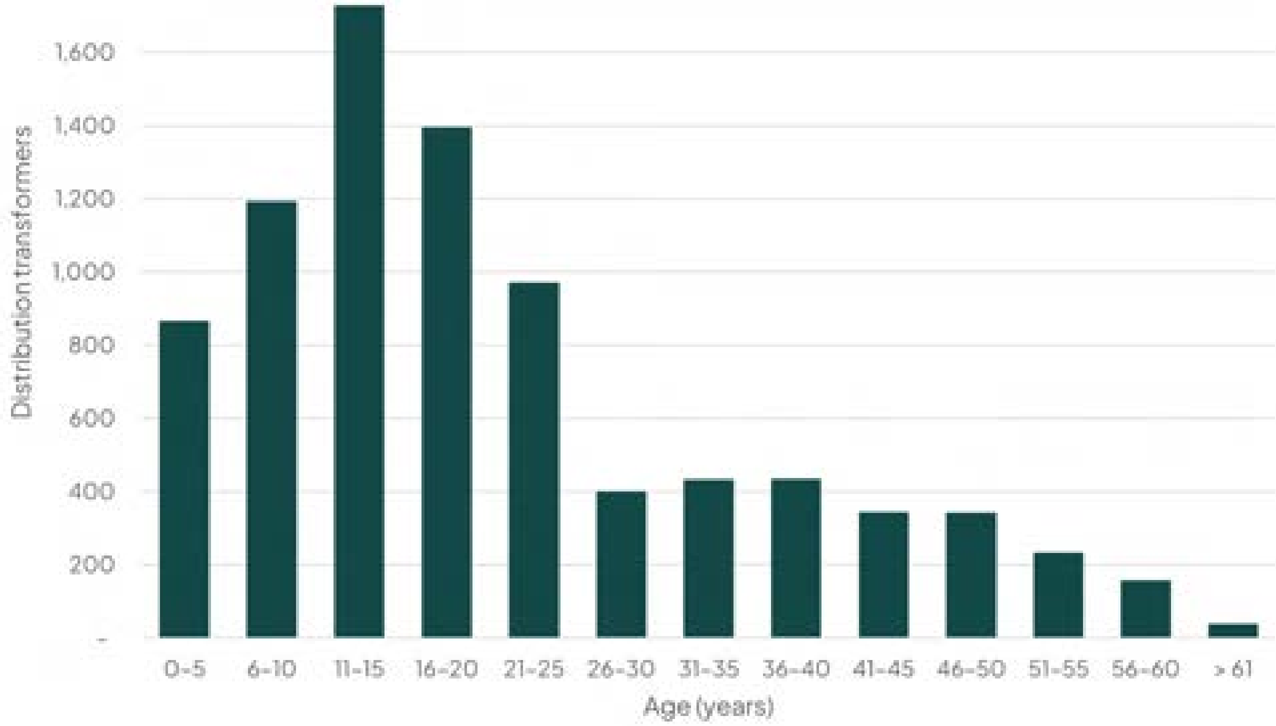


Figure 3.11 Age profile of our distribution transformers (FY25)

3.4.3 Voltage regulators

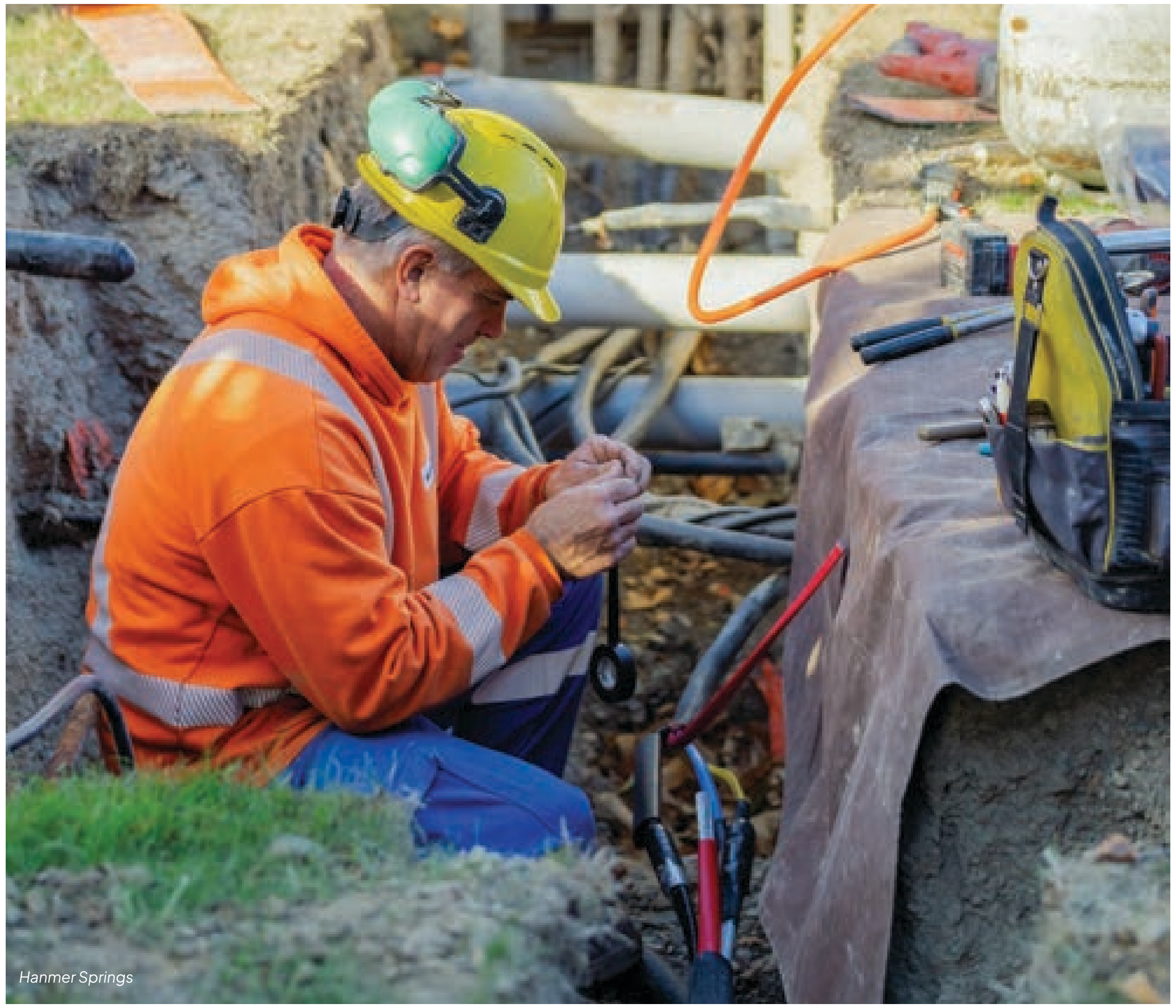
There are 26 single-phase 11 kV regulators across 12 sites, most rated at 22 kV with automatic controls. They typically last 45 years and are performing well with no planned replacements. When retired, they are disposed of under standard oil-filled equipment procedures.

Lochiel zone substation

3.5 Underground assets

Table 3.3 Underground asset portfolio (FY25)

Asset type	Length/Quantity
High-voltage underground cables	404 km
Low-voltage underground cables	1,390 km (including streetlight circuits)
Low-voltage service boxes	14,000
Low-voltage link boxes	754



Hanmer Springs

3.5.1 High-voltage underground cables

High-voltage cables are mainly 95 mm² or 185 mm² aluminium conductors, with 300 mm² used for major urban feeders and 35 mm² for rural spurs. Most assets are in good condition, with issues usually limited to joints and terminations. Replacements are based on inspection results or faults, with several 33 kV sections scheduled within 10 years. Recovered cables are recycled.

Table 3.3 details our underground asset portfolio, while Figure 3.12 provides the age of our high-voltage cables and Figure 3.13 the current health of these assets.

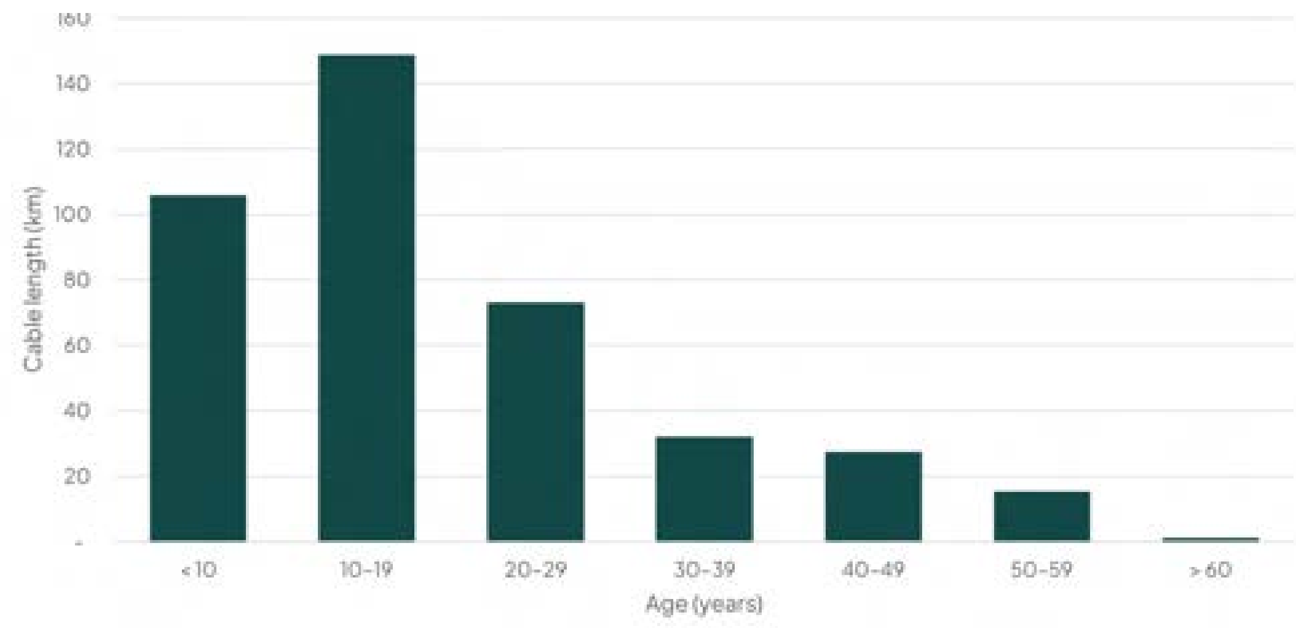


Figure 3.12 Age profile of our high-voltage cables (FY25)

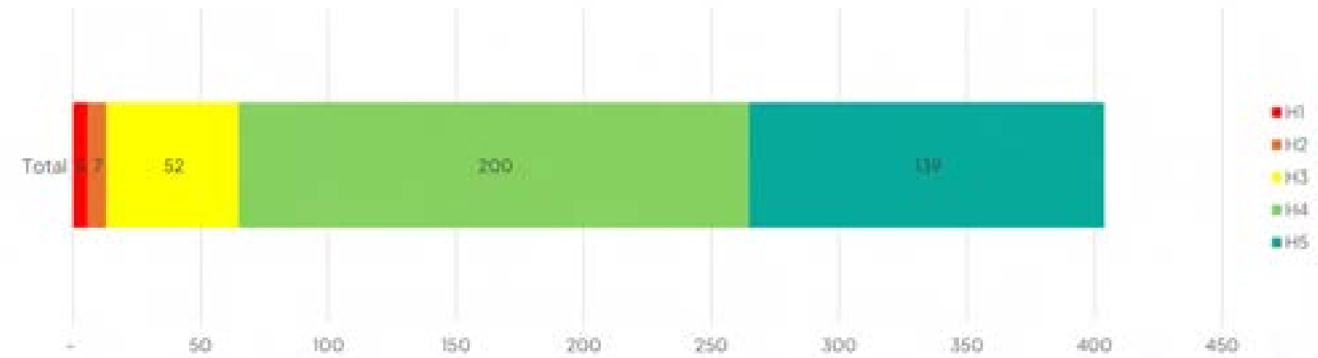


Figure 3.13 Asset health of our high-voltage cables (FY25)

3.5.2 Low-voltage underground cables

Low-voltage underground cables supply electricity from distribution transformers to homes and businesses at 400 V or 230 V. Most use aluminium conductors (95–185 mm²), while smaller copper cables remain in some older areas. Replacements are triggered by fault history or condition assessments.

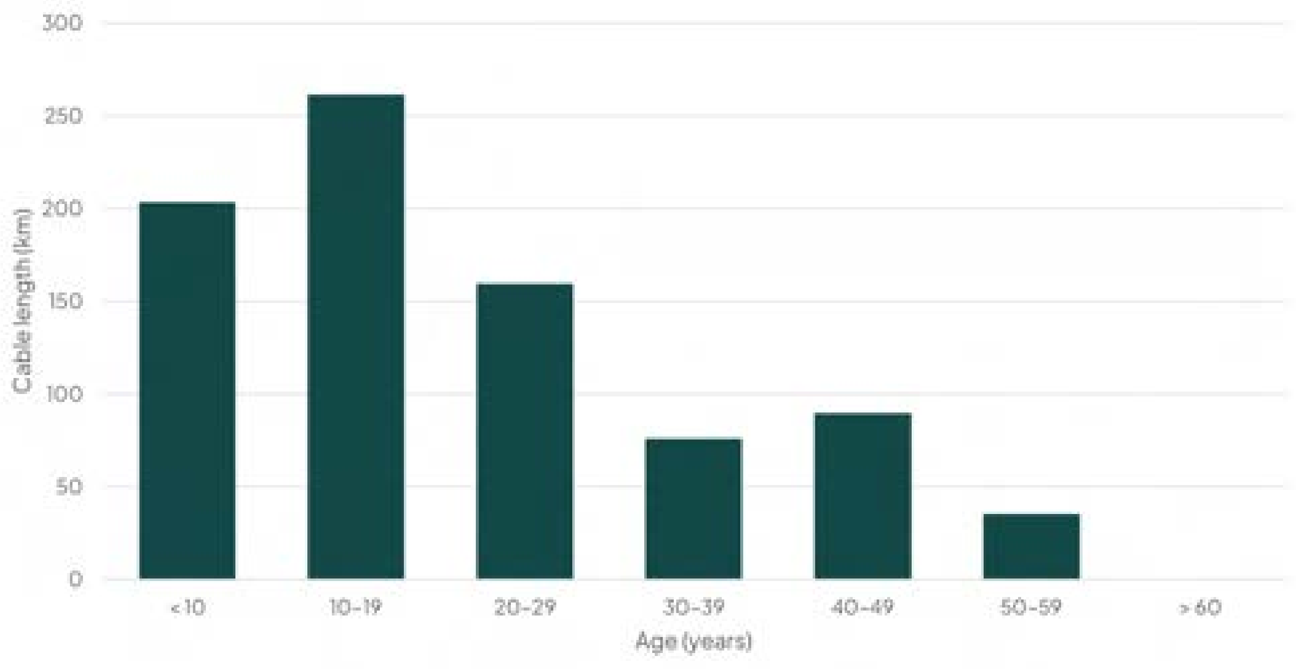


Figure 3.14 *Age profile of our low-voltage cables (FY25)*

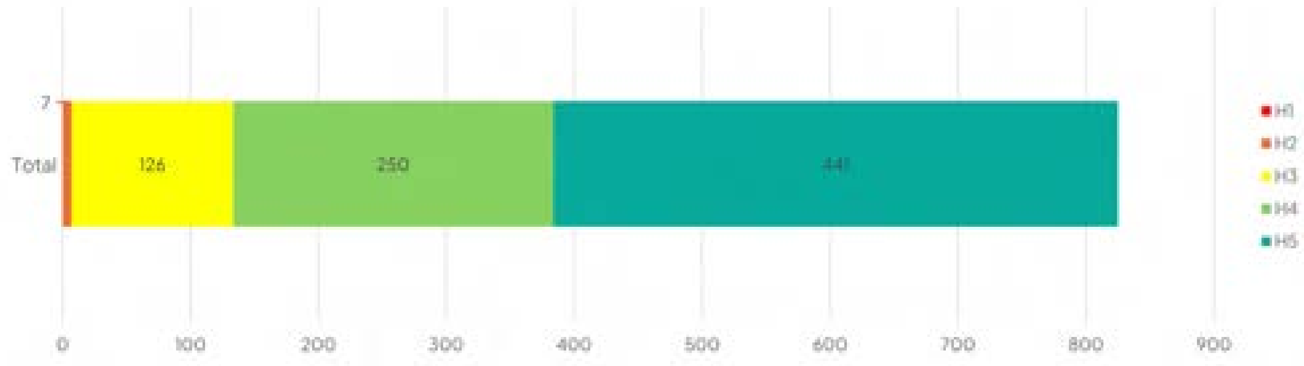


Figure 3.15 *Asset health of our low-voltage cables (FY25)*

3.5.3 Service and link boxes

Service boxes connect customer supply lines, while link boxes join sections of cable. Replacement is prioritised by condition and safety risk. Metal boxes are recycled, fibreglass and plastic boxes are disposed of as general waste, and any asbestos-containing units are handled by licensed contractors.

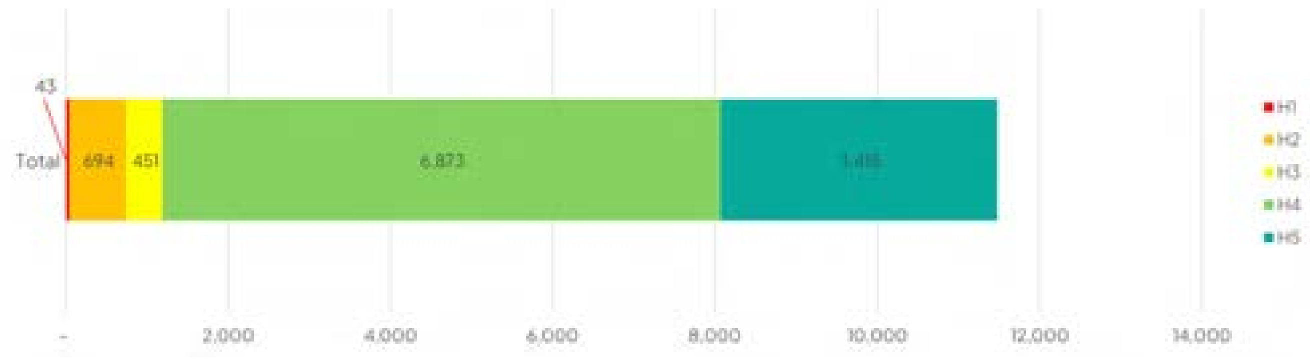


Figure 3.16 *Asset health profile for our service boxes (FY25)*

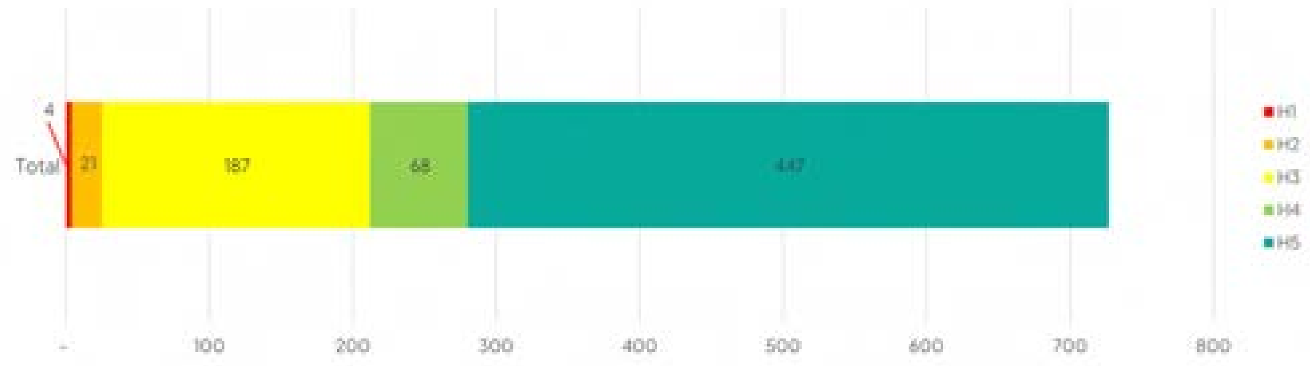


Figure 3.17 *Asset health profile for our link boxes (FY25)*

3.5.4 Secondary systems

Secondary systems monitor, protect, and control the network, ensuring faults are detected and power is restored quickly. They include backup DC systems, protection relays, communication links, and load-control equipment.

3.6 DC batteries and chargers

Table 3.4 DC battery inventory (FY25)

Nominal life	Quantity
10 years	253
5 years	273
1 year	3
Total	529

DC systems provide backup supply for critical devices during outages. Replacement is prioritised based on age and condition, with premature failures replaced immediately. Chargers are renewed at end of life or when modern supervisory control and data acquisition (SCADA) functionality is required. Table 3.4 outlines our current CC battery inventory.

3.6.1 Protection relays

Protection relays detect and isolate network faults automatically. Replacement is coordinated with switchgear renewal to minimise costs. Older mechanical relays are being replaced by modern digital types that provide faster and more accurate protection.

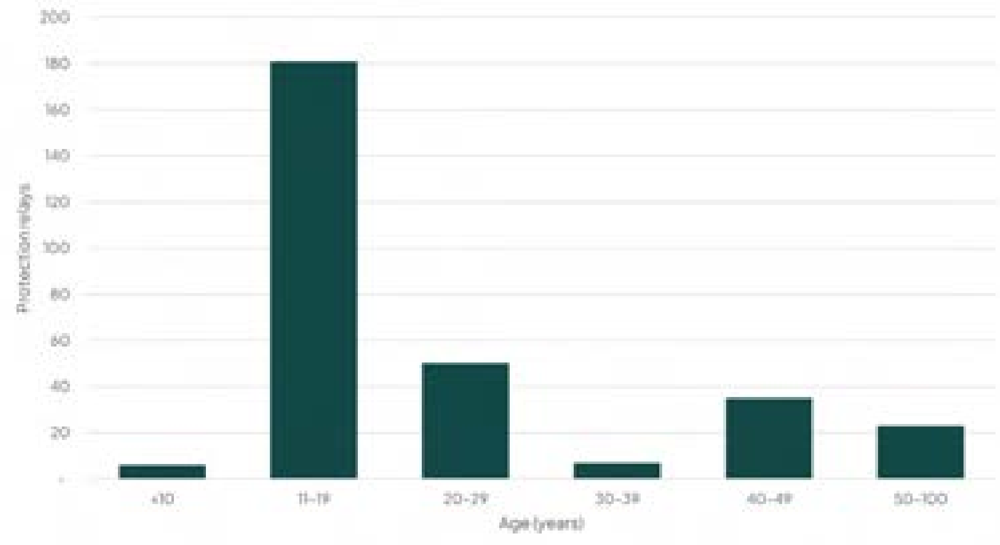


Figure 3.18 Age profile of our protection relays (FY25)

3.6.2 Communications and SCADA

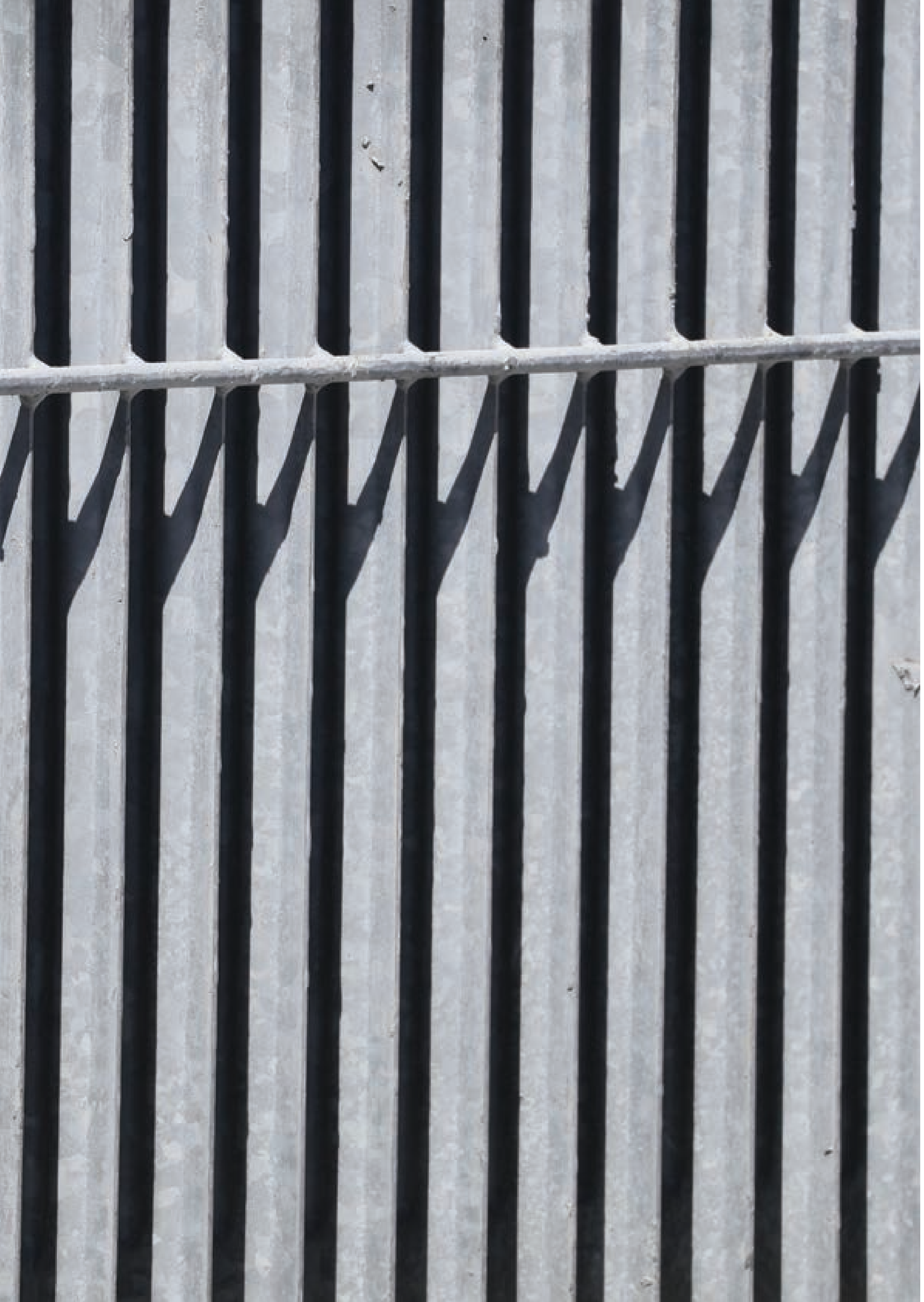
Our communication network combines radio and fibre technology across Waimakariri and Kaikōura. The advanced distribution management system (ADMS) monitors and controls equipment across the network. Digital radio systems (Mimomax, Dataradio, Racom RipEX) are being expanded, and older analogue systems are progressively replaced to improve speed and reliability.

Rangiora

3.7 Vegetation management

Managing trees and vegetation near power lines is critical for both safety and reliability. Most of our overhead lines pass through rural landscapes where vegetation poses a significant risk during storms.

Our vegetation management programme combines regular inspections by qualified arborists, proactive trimming, and community engagement to help landowners understand their responsibilities. Particular focus is placed on high-fire-risk areas as changing weather patterns bring drier conditions. The vegetation strategy is reviewed regularly to incorporate new technology and delivery methods that improve safety and efficiency.



3.8
Load control and ripple injection plants

Ripple injection systems are a tool that helps us control when certain electrical loads operate. This system keeps everything running smoothly, ensures fair pricing, and helps us avoid unnecessary strain on the network, especially during busy times.

Our ripple injection plant works by sending coded signals through the power lines. These signals are picked up by devices called load control receivers, which are mostly built into smart meters, or are stand-alone units installed in the 1990s and early 2000s. Each plant operates at a set frequency, and all the equipment is carefully synchronised using GPS technology to ensure precise, reliable operation.

We are actively replacing older receivers with modern versions that are more efficient and easier to manage. As a result, the number of legacy receivers is steadily decreasing. Table 3.5 shows where our ripple injection plants are located, how old they are, and the voltages they use.

Table 3.5 Ripple injection plant location, age, and operating voltage (FY25)

Location	Age (years)	Operating voltage (kV)
Ashley GXP	9	11
Burnt Hill	9	22
Kaiapoi GXP	29	11
Ludstone Road	29	11
Mouse Point	29	33
Southbrook	2	11
Swannanoa	9	22
Waipara GXP	16	66

Recently, we upgraded our Southbrook system, replacing an older high-voltage unit with a more suitable one as part of our ongoing improvements. We were able to repurpose equipment from this project to upgrade other sites, making the most of our resources and ensuring continued reliability.

3.9 Property

We own and care for a variety of buildings, including our main offices, sites that support our communications, control buildings at key substations, and smaller structures that house important electrical equipment. Table 3.6 shows the different types and numbers of these buildings.

Table 3.6 Property and building assets (FY25)

Building type	Quantity
Zone substation control building	22
Distribution substation	34
Holiday home	2
Office	4
Repeater site	5
Staff house	2
Storage building	4
Equipment and kiosk cover	933
Total	**1,006**

Rangiora Head Office

3.9.1 Zone substation control buildings

We have 22 zone substation control buildings located throughout our network area. These buildings come in different sizes and styles, from small portable sheds with up to five control panels, to larger, permanent buildings with multiple rooms, indoor switchgear, and even toilet facilities. Table 3.7 shows the types and uses of these buildings.

Table 3.7 Zone substation control building types (FY25)

Construction type	Control only	Control high-voltage switchgear
Timber framed	5	2
Concrete block	4	2
Concrete tilt slab	0	7
Container	0	2
Total	**9**	**13**

We have completed thorough checks on each one in the last financial year. This included detailed assessments for earthquake safety and compliance with building standards, and presence of asbestos.

Based on the results of our structural assessments, all zone substation control buildings are in good shape and do not have any serious faults. As a result, we are not planning to replace any of these buildings in the next 10 years.


Rangiora

3.9.2 Distribution substation buildings

We have 34 distribution substations that each sit in their own stand-alone building. They are made from sturdy materials like concrete or masonry, designed to last. Inside, you'll find equipment that helps safely manage the flow of electricity. The age of these buildings ranges from 20 to 62 years, with most falling between 50 and 60 years old (see Figure 3.19).

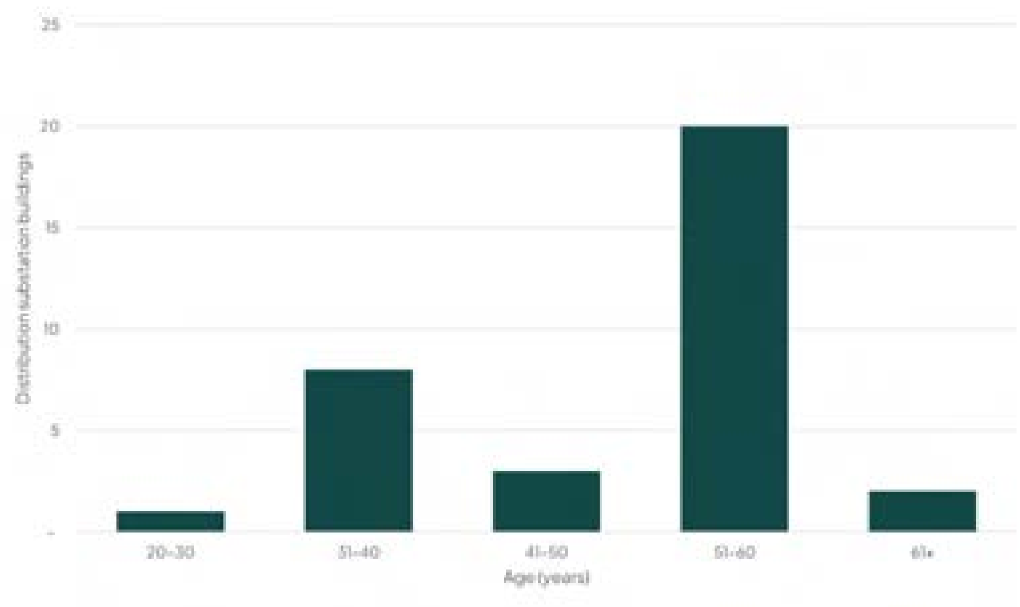
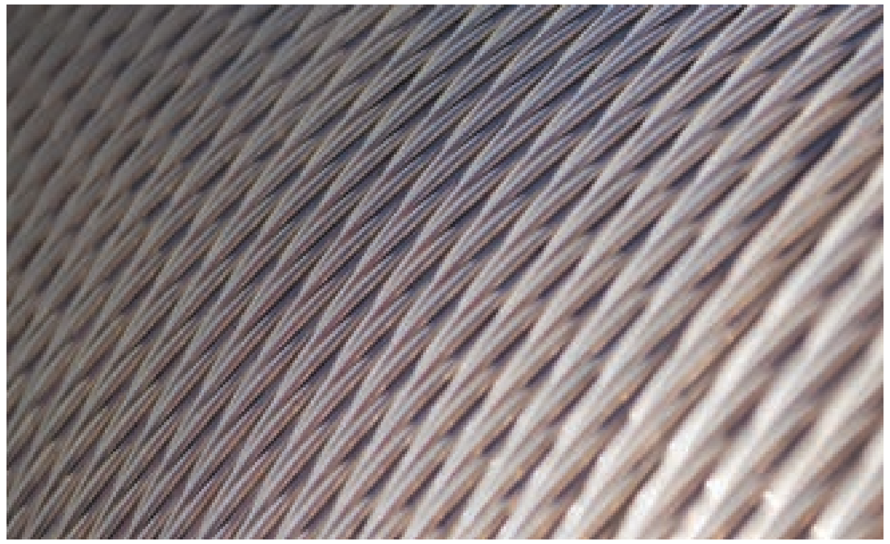


Figure 3.19 Age profile of distribution substation buildings (FY25)

Despite their age, these buildings remain in good condition and continue to serve our community well. In the 2019 financial year, we carefully inspected each one to make sure they are safe and fit for purpose. Some buildings needed minor strengthening, mainly in their roofing.

Since our structural checks found no major faults, we are not planning to replace any of these buildings over the next 10 years. If we discover asbestos in any building, we will handle its removal in line with our strict asbestos management plan, ensuring the safety of our staff and the public.



3.9.3 Distribution kiosks

Distribution kiosks are small, ground-level covers that protect important electrical equipment in our community. These covers are made from strong materials like steel, fibreglass, or plastic. Figure 3.20 shows the age profile of our kiosks.

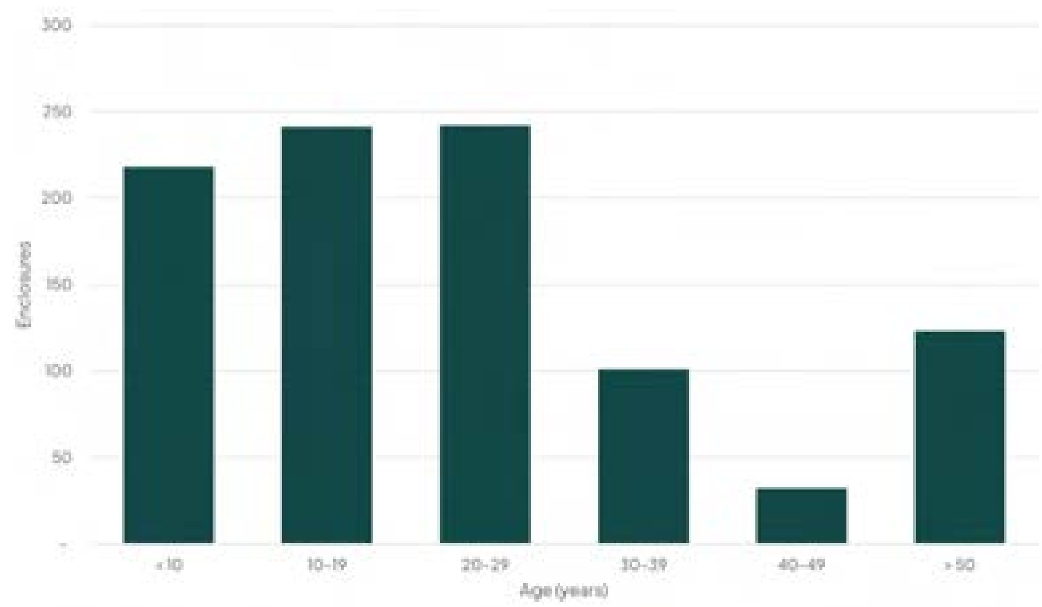


Figure 3.20 Age profile of kiosk covers (enclosures) (FY25)

We regularly inspect all kiosks and if we find a problem, we either repair the cover or, if needed, replace it. When it's time to dispose of an old kiosk, we always follow our standard process to do so safely and responsibly.

Currently, we don't have a set schedule for replacing kiosk covers. Instead, we focus on fixing any defects as soon as we find them, or we coordinate replacements with other planned work.

3.9.4 Non-electricity distribution network buildings

Across North Canterbury, we own offices, administration spaces, operational buildings, and accommodation for staff and visiting workers. Table 3.8 provides a summary of these facilities.

Table 3.8 Non-electricity distribution network buildings (FY25)

Description	Location	Age (years)
Staff housing – #1	Culverden	5
Staff housing – #2	Culverden	4
Office building	Culverden	43
Storage shed/workshop	Culverden	43
Operational facilities	Kaikōura	1
Holiday home	Hanmer Springs	43
Holiday home	Kaikōura	43
Corporate office and operational facilities	Rangiora	10

Our main office is in Rangiora, where we manage the business and oversee the electricity distribution network. The site brings together our corporate and operational teams to ensure the reliable delivery of electricity at the best value for our customers. The office complex includes a two-storey building built to a high safety standard (Importance Level 4), which means it's designed to keep operating even during significant events. On site, there is also a single-storey café (Importance Level 3), offering a welcoming space for staff and visitors, and a large single-storey building used for storage, vehicle maintenance, and workshops, which also has a mezzanine level for extra storage (also built to Importance Level 3 standards).

For operational reliability and safety, our network operations centre and server room are both located within the main office building. We have robust plans in place to keep these services running if there's ever a disruption. If needed, our staff can work remotely to ensure essential operations continue smoothly, supporting uninterrupted service to our customers. In addition, our head office serves as a backup emergency response centre for local authorities, providing a safe and reliable base if their own facilities can't be used in a crisis.

To further protect our staff and community, we have installed a ground acceleration monitor on site. After an earthquake, this device quickly sends us data within 90 seconds that shows how strongly the ground shook. This information helps us check the safety of our buildings and respond quickly if repairs are needed, making sure our services remain safe and reliable for everyone.

We are committed to maintaining these buildings to a high standard so they continue to serve our community for years to come.

Kaikōura depot

3.10 Mobile generation capabilities

Secondary systems monitor, protect, and control the network, ensuring faults are detected and power is restored quickly. They include backup DC systems, protection relays, communication links, and load-control equipment.

Mobile generators allow us to maintain supply during planned maintenance or emergencies, minimising disruption for customers. Table 3.9 outlines our current mobile generator fleet.

Table 3.9 Mobile generation fleet

Equipment type	Capacity	Primary application
Trailer-mounted diesel generators	500 kVA	Zone substation backup and major maintenance
Portable diesel generators	50–150 kVA	Localised backup for distribution transformers
Emergency response generators	Various	Critical customer support during extended outages

3.11 Assets at network connection points

We operate a variety of assets at Transpower's GXPs, which are where our network connects with the national grid. At these sites revenue meters are installed to track how much electricity is flowing in and out. These meters play a crucial role in making sure we can manage demand. Alongside this, we have specialised equipment that communicates with our distribution network to measure exactly how much electricity is used, and where it is used, which is important for managing the supply of electricity to our customers.

To help control when and how electricity is delivered, we also operate ripple injection plants. These plants send signals through the power lines, allowing us to manage electricity use across the community, especially during busy times.

3.12
Asset lifecycle management summary

Our lifecycle management approach balances reliability, cost, and risk across all asset categories. Key principles include:

- using condition-based replacement rather than age alone
- conduction regular inspection and monitoring programmes
- coordinating work to maximise efficiency and minimise outages
- recycling and responsible disposal of retired equipment
- continually improving asset-health models and forecasting
- integrating lifecycle planning with wider network investment strategies

This structured approach ensures we continue to deliver a safe, dependable, and affordable electricity supply for North Canterbury while using our customers' money wisely.

Kaikōura

3.13 Our people and delivery capacity

Delivering this AMP relies on capable people, effective systems, and strong partnerships. Our people are at the heart of our ability to plan, build, operate, and maintain a safe and reliable electricity network. This section explains how our workforce is structured, how we build and retain essential skills, and how we assess our ability to deliver the forecast work programme.

3.13.1 Workforce structure

Our workforce includes a diverse mix of technical, operational, and professional staff who collectively support the delivery of our AMP. We currently employ 175 full-time equivalent (FTE) staff across several key functions. Table 3.10 outlines our workforce by functional area.

Table 3.10 Workforce by functional area (FY25)

Functional area	FTE count	Part time and fixed term	Primary responsibilities
Network operations and maintenance	92	2	SCADA, outage management, switching operations, preventive maintenance, inspections, vegetation management
Asset management and network development	41	2	Project delivery, network connections, construction management, strategic planning, investment analysis, performance monitoring, network design, technical standards, protection engineering
Customer service	8	0	Customer enquiries, connections administration, complaints handling
Corporate support	30	3	Finance, HR, IT, governance, regulatory compliance, safety, training, communications

We supplement our internal workforce with trusted contract partners, who provide additional capacity for capital projects, specialised technical services, and seasonal work peaks.

3.13.2 Skills and competencies

Our people hold the technical qualifications and professional competencies required for their roles. We maintain clear competency frameworks for all critical positions to ensure work is completed safely, efficiently, and to a high standard.

Key areas of expertise across our workforce include:

- electrical engineering and design (registered electrical engineers, network design specialists)
- high-voltage switching and network operations (authorised switching personnel)
- live-line work (trained and certified live-line crews)
- protection and control engineering (relay setting, SCADA configuration)
- project management (formal project management qualifications)
- asset management (understanding of ISO 55000[6] principles).

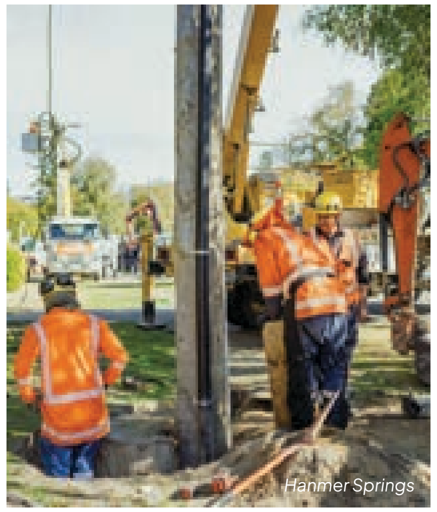
3.13.3 Training and developing our people

We invest in structured training programmes to maintain technical excellence, meet regulatory requirements, and provide development opportunities for our people.

Our training framework includes:

- technical apprenticeships for lines people and electricians
- high-voltage switching recertification every three years
- safety and compliance training, including confined spaces, working at heights, and hazard management
- engineering development, including protection, SCADA, and design specialisations
- leadership and management programmes for emerging and experienced leaders
- continual professional development for all engineering and asset management roles.

Training records are maintained through our learning management system, and each role has defined competency requirements. We conduct regular assessments to ensure that our people continue to meet these standards.



Hanmer Springs

[6] *ISO 55000 is a series of international standards for asset management.*

3.13.4 Contractor management

We work closely with qualified contractors, who are an essential part of our delivery model. This partnership approach gives us flexibility to manage peaks in workload and access specialist expertise when required.

Our contractor management process includes:

- prequalification assessments of technical capability, safety performance, and financial stability
- clear contract specifications setting out quality standards, safety expectations, and performance criteria
- site supervision and quality inspections during delivery
- competency verification for key personnel
- regular performance reviews and feedback to drive improvement
- safety audits and incident investigations where required.

We maintain long-term relationships with approved contractors in construction, maintenance, vegetation management, and specialist engineering disciplines. These partnerships ensure we can scale delivery capacity when needed.

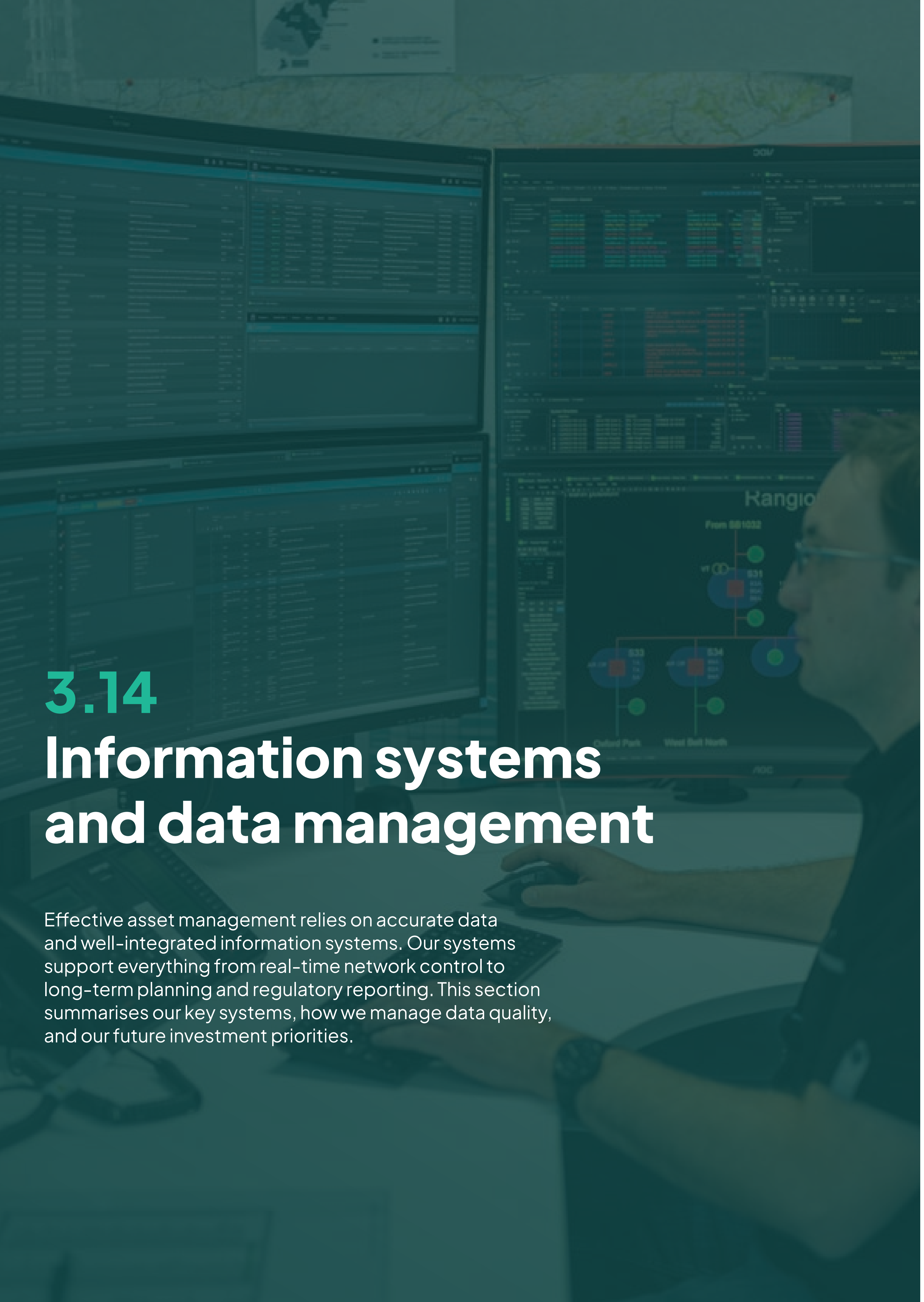
3.13.5 Assessing our delivery capacity

We regularly assess our capacity to deliver the forecast work programme, considering both internal resources and contractor availability. Based on our assessment, we have adequate capacity to deliver the core work programme. However, we identified the following delivery risks:

- Competing demands from other EDBs in the region, which may constrain contractor availability during peak periods
- Skilled labour shortages in specialised trades (protection engineers, experienced lines people)
- Supply chain delays for long-lead equipment (transformers, switchgear)
- Weather-related delays affecting outdoor construction work
- Resource consent timeframes for major projects

We mitigate these risks through forward planning, maintaining relationships with multiple contractors, early equipment procurement, and flexible work scheduling.

We are committed to finding smarter ways of working so we can make the best use of our people and resources. If you would like to learn more about how we are improving in this area, please see section 5 for further details.



3.14 Information systems and data management

Effective asset management relies on accurate data and well-integrated information systems. Our systems support everything from real-time network control to long-term planning and regulatory reporting. This section summarises our key systems, how we manage data quality, and our future investment priorities.

3.14.1 Core information systems

We operate several integrated systems supporting asset management and network operations (Table 3.11 and 3.12).

Table 3.11 Core information systems

System	Primary function	Criticality
Geographic information system (GIS)	Network asset register, spatial data management, field updates	Critical
Enterprise resource planning (ERP)	Financial management, procurement, work costing, asset accounting	Critical
Advanced distribution management system (ADMS)	Real-time monitoring, remote control, alarms, and automation	Critical
Customer relationship management (CRM)	Customer records, connections, and enquiries	High
Smart meter data	Consumption, voltage, and power quality data from smart meters	High
Data warehouse and visualisation software	Consolidated analytics and performance reporting	High
ADMS	Outage detection, restoration tracking, and crew dispatch	Critical

3.14.2 Data quality management

Table 3.12 Data quality management

Focus area	Key practices	Customer and operational benefits
Governance and ownership	Clear data stewardship roles, defined accountability, and approval processes	Improved accuracy and transparency in reporting
Validation and controls	Built-in system checks to prevent incorrect or duplicate entries	Reduces errors and ensures reliable data for decision-making
Auditing and cleansing	Regular audits and correction of historical records	Maintains long-term data integrity
Staff training and awareness	Training on consistent data entry standards and correct use of systems	Improves consistency and reliability of field and office data
Integration and automation	Direct links between systems (e.g. GIS-ERP-SCADA) to avoid double entry	Creates a single source of truth for asset and performance data

3.14.3 Known data limitations

Good asset management depends on high-quality, reliable data. While our core systems provide strong visibility of network performance, we recognise that some data gaps still limit the depth of analysis available for certain asset classes and functions.

For many older assets, condition information is still based mainly on visual inspection and periodic testing rather than continuous monitoring. This limits the ability to model deterioration trends or predict failures in real time. Similarly, load visibility across the low-voltage network remains incomplete because smart meters are not yet universal across all customers. Expanding smart meter data coverage and improving analytics will allow us to better understand where and when our network is under pressure.

Some older asset records also contain approximate installation dates because of missing historical documentation. Although this does not affect operational safety, it can reduce the precision of long-term lifecycle forecasts. In addition, parts of our historical maintenance data are stored on paper or in legacy systems, making them harder to integrate into our digital tools.

Finally, while our outage management systems are effective, customer contact data remains incomplete in some cases. Not all customers have provided mobile numbers for text alerts, limiting the reach of our outage notifications.

Our ongoing data improvement programme is addressing these issues through better system integration, digitisation of legacy records, and expanded use of field-based digital data capture. These initiatives, combined with process improvements and staff training, are steadily enhancing the quality and reliability of our information for decision-making and reporting.

3.14.4 Cybersecurity

Our approach to cybersecurity is designed to safeguard all our digital assets across both local and cloud environments, making sure our systems stay protected and service remains uninterrupted.

To keep our information safe, we use a security system that works across all our technology, whether it's in our local data centre or in the cloud. This system is based on trusted, industry-standard technology and is built to respond quickly to any potential threats. It constantly monitors our network for unusual activity, checks for any weak spots, and can react automatically to keep things secure. If a risk is detected, our team is alerted so we can take action straight away.

By having centralised tools that watch over our entire IT network, we can spot issues early, respond quickly, and keep track of everything in one place. This helps us prevent problems before they affect your service and ensures we meet the standards expected in our industry.

3.14.5 Systems investment plan

These investments support improved operational efficiency, better customer service, and enhanced network visibility.

To support a smarter, more efficient electricity network, we are investing in a series of system upgrades over the planning period. These investments focus on improving operational efficiency, customer experience, and the visibility of network performance.

A major initiative is the rollout of a mobile GIS platform, which gives field crews access to accurate network data in real time and allows them to update asset information directly from site. This reduces errors, shortens response times, and ensures asset records remain current.

We are also upgrading the ADMS, which integrates network monitoring, outage management, and control functions on a single platform. This system upgrade will enable smarter automation, faster restoration during outages, and improved coordination of distributed generation.

At the customer interface, a new self-service portal will allow customers to track connections, check outage information, and manage their details online, improving transparency and convenience.

In addition, we are developing a smart meter analytics platform to make better use of the increasing volume of consumption and voltage data available. This will enable more accurate forecasting, early fault detection, and enhanced understanding of network demand patterns.

Supporting these initiatives are continued investments in data integration between GIS and ERP systems and ongoing upgrades to cybersecurity infrastructure. These will ensure our digital environment remains secure, resilient, and compliant with best-practice standards.

Together, these investments will provide better data, faster insights, and stronger network visibility, enabling us to deliver reliable, efficient, and customer-focused electricity services across North Canterbury.

3.15 Asset management maturity and improvement

We review our asset management practices using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT). This helps us understand how effectively our systems and processes support reliable, efficient, and customer-focused network management, and where further improvement is needed.

3.15.1 AMMAT assessment results

In February 2025, we completed an internal assessment of our asset-management maturity using the AMMAT. Our in-house team followed the same scoring approach and framework as in previous years, allowing us to track progress and measure how well we are performing over time.

The internal review produced an overall maturity score of 2.7 out of 4, which is consistent with the results of our previous AMP assessment. These outcomes confirm that our asset management framework remains sound and continues to develop in key areas, supporting reliable, affordable, and customer-focused electricity delivery.

Our assessment looked across five main areas of asset management practice:

- **Governance and strategy:** How well we plan strategically and align decisions to our purpose
- **Lifecycle management:** How we manage assets through their full lifecycle from acquisition to disposal
- **Risk management:** The robustness of our risk frameworks and how we integrate risk into decisions
- **Information and data:** Quality of our data and information management practices
- **Stakeholder engagement:** How effectively we engage with customers and stakeholders.

Key strengths

The assessment identified the following as areas of strength:

Engaged people and culture
Our teams show a positive "can-do" attitude and a shared commitment to delivering value for customers.

Resilience and readiness
Comprehensive emergency and recovery plans mean we can respond quickly to events and keep your lights on.

Competency and training
Staff training and development programmes are well established, building capability for the future.

Clear direction and alignment
Our Asset Management Policy and Strategy are well connected to our corporate goals and MPowered Future values, ensuring investment decisions are purposeful and transparent.

Lifecycle planning
Each asset class has a clear, risk-based plan covering maintenance, renewal, and replacement, helping us deliver reliable service while managing costs.

Improvement opportunities

The assessment also pointed to areas where further improvement will help us deliver even better value and service for customers:

Better understanding of asset risk
We are combining condition, performance, and criticality data so we can target replacements and maintenance more accurately, reducing the likelihood of unexpected outages.

Future workforce planning
We're developing long-term forecasts for skills and staffing to ensure we have the right people and expertise to meet changing customer needs.

Improved field data capture
We're extending mobile tools and digital inspection processes, giving us more accurate, real-time information to plan maintenance and respond to issues.

Smarter use of data
We are improving how information flows between systems like GIS, ERP, and ADMS so everyone works from one reliable source. This will mean faster insights, better forecasting, and fewer delays.

Stronger investment decision-making
We're enhancing our asset management models to weigh the probability and consequence of asset failures, helping us focus investment where it delivers the greatest benefit.

3.15.2 Asset management improvement programme

Based on the AMMAT assessment and our own analysis, we have developed an improvement programme targeting five key areas (Table 3.13).

Table 3.13 Asset management improvement programme

Improvement area	Key actions	Target completion	Expected benefits
Governance and alignment	Refresh the Asset Management Policy and Strategy to reflect evolving corporate objectives and refreshed MPowered Future values. This builds on an already strong governance framework.	FY27	Keeps our investment decisions clearly linked to purpose and ensures customers continue to see value for money as our strategy evolves.
Risk and decision-making	Develop advanced risk-modelling tools that link the likelihood and consequence of asset failures, supporting stronger prioritisation of investment and maintenance.	FY27–FY28	Investment choices are clearer and more transparent, helping to maintain reliability while managing long-term costs.
Data and information systems	Implement a data governance framework; connect GIS, ERP, and ADMS platforms; and complete the move to mobile field-data capture.	FY27–FY28	Everyone works from one reliable source of information, improving forecasting and reducing delays.
Lifecycle planning	Review renewal strategies and update asset health/risk models with enhanced field data inputs.	FY26–FY27	Smarter renewal timing and better use of every dollar invested, keeping the network reliable and affordable.
People and culture	Continue building asset-management capability through training, mentoring, and cross-team collaboration, and embed succession planning for key roles.	Ongoing	A skilled, motivated workforce ready to deliver safe, dependable service as the network and technology evolve.

Progress against these actions is monitored through our internal governance processes. We aim to progress identified improvement activities each year, with results reported in future AMP updates.


Amberley zone substation


Lochiel zone substation

3.15.3 Continual improvement culture

Beyond formal assessment cycles, we maintain a strong culture of continual improvement across all parts of the business. Our people are encouraged to identify opportunities, learn from experience, and apply good practice from across the industry.

We regularly review and update our asset-management processes and documentation to make sure they remain fit for purpose. Lessons from incidents, near-misses, and project reviews are shared across teams so we can refine how we plan, deliver, and manage our work. We also benchmark our performance against other New Zealand EDBs to understand where we are leading and where we can do better.

We actively participate in industry working groups and adopt emerging standards to stay aligned with best practice. Staff receive ongoing development and training in asset-management principles, digital tools, and data-driven decision-making. Close collaboration between field, engineering, and planning teams ensures that insights flow freely through the organisation, helping us work more efficiently and consistently for our customers.

This commitment to continual improvement ensures that we remain adaptable and forward-looking as customer expectations evolve, technology advances, and the electricity sector continues to transform.

4 Building the network of the future

This section provides an overview of how we are preparing our electricity network to meet the future needs of our growing region. You'll find information on our forecasting methods, the decision-making process behind major projects, and how we prioritise investments to support network resilience. This section also highlights the major projects underway in your area and explains how community feedback influences our planning to ensure affordable, reliable power for years to come.

What you will find in this section

- How we're planning for the future of the network
- Where we're investing in network intelligence
- How we're managing growth demands across our network
- Major projects happening in your area
- What our planning processes mean for you

4.1 We're planning for the future

North Canterbury is growing. More families are moving to our region, new businesses are opening, and existing industries are expanding. With this growth comes increased demand for electricity – not just more power, but power that is reliable, affordable, and ready when it is needed.

Our network development strategy is our commitment to you that we will keep pace with this growth. We are planning today so that in 10, 15, or 20 years, when you flick a switch, the power will be there. This section explains how we are working to build a network that serves our growing community while keeping costs as low as possible.

You have told us through our customer surveys that you value reliability and want us to keep costs down. Most of you have also told us you prefer we maintain current service at current prices rather than paying more for improvements. We have listened, and these priorities shape every decision we make about network development.

Hanmer Springs

4.2 Climate change and network resilience

Our electricity distribution network increasingly faces challenges as a result of climate change. Rising temperatures, decreased rainfall, and more severe weather events have begun to place additional strain on our systems. Recent years have seen storms cause significant damage and resulting outages, impacting both overhead and underground infrastructure.

For you, this means we need to build a network that can withstand these harsher conditions. We are incorporating climate resilience into our AMP, influencing how we select equipment, plan routes, and design infrastructure. The goal is simple: keep your power on, even when the weather does its worst.

A practical example is our approach in Hanmer Springs. Rather than building a second expensive line through challenging alpine terrain that is increasingly vulnerable to extreme weather, we are installing backup diesel generation (explained in further detail later in this section). This means that even when adverse weather damages the main subtransmission supply, the most significant sections of Hanmer can be powered by an alternative source.

Hanmer Springs

4.3
Building our plans around our stakeholders

We work hard to keep costs down for our customers by staying in close contact with local councils, Transpower, and NZ Transport Agency Waka Kotahi (NZTA)across our network. By connecting with these groups early on, we can better understand what they need along with the needs of our wider community. This helps us plan ahead and find the right solutions, making sure we deliver reliable electricity at the lowest possible cost for everyone we serve.


Hanmer Springs

Planning jointly with Transpower

When both MainPower and Transpower need to upgrade infrastructure in the same area, we have a choice: we can each build our own separate solutions, or we can work together to find the most cost-effective overall answer. We have chosen to work together.

Through our joint Long-Term Planning Investigation with Transpower, we have mapped out where demand will grow, identified future constraints, and designed coordinated upgrades. This means we are not duplicating infrastructure or missing opportunities to share costs. For you, this translates directly into lower electricity bills – because ultimately, you are paying for both Transpower's transmission network and MainPower's distribution network through your power costs.

A key outcome of this collaboration is our plan for the new Coldstream zone substation. Rather than building entirely separate connection routes, we have designed a smarter approach that connects Coldstream into the existing network in the Fernside area. This modification increases the long-term capacity of the whole network while reducing the total infrastructure we need to build. It is about delivering what you need without building more than necessary.

We have also coordinated with Transpower on 66 kV network modifications to allow for new connections, and we are building strategic switching stations at Ashley and Waipara. Both Ashley GXP and Waipara GXP have limited space for expansion. Rather than forcing expensive modifications to Transpower's substations, we are building nearby switching stations that give us flexibility to make multiple connections without the space constraints. It is a more cost-effective way to build a flexible, resilient network.

Coordinating on roading projects

Major roading projects like the Woodend Bypass and Rangiora Eastern Link are not just about better roads – they are opportunities to plan smarter for electricity infrastructure.

We are working closely with NZTA and the Waimakariri District Council to install underground ducts for future power cables while these roads are being built. It sounds simple, but the savings are significant. Installing ducts during road construction costs a fraction of what it would cost to dig up completed roads later. These ducts will sit empty for now, ready for when we need to run high-capacity cables through them as the region grows.

We have allocated budget to allow for the installation of ducts during the Woodend Bypass project. The bypass will include interchanges and bridges, and the proposed route for our subtransmission cabling includes road crossings. In constrained areas like these, it can be considerably cheaper to install ducts during construction. This approach could save hundreds of thousands of dollars compared to retrofitting later.

We are also working with the Council to understand which roads will become busier over time, helping us route power lines along quieter roads where they are safer and less disruptive. This forward planning means better, more affordable infrastructure for everyone.

4.4
Managing demand and enabling flexibility

4.4.1
Forecasting future demand through modelling

Before we invest in infrastructure, it's important for us to understand how much electricity people will need in the years ahead. We take a careful and thorough approach to forecasting, looking at many different factors that can influence electricity demand in North Canterbury. Getting these forecasts right allows us to build or improve infrastructure where and when it's needed, so we can avoid both outages caused by not having enough capacity and unnecessary spending on projects that aren't required yet.

Our forecasting model helps us predict the future load at each substation and grid connection point. This model uses information about expected population growth, the rising use of EVs, more homes and businesses with solar panels and batteries, and the number of new electricity connections. We also consider large commercial projects and planned network improvements, as well as changes in demand that might come from new technology in the community.

To make sure our forecasts are as accurate as possible, we rely on up-to-date figures from the national census and population projections, council growth plans, and NZTA vehicle statistics. For each substation, we prepare several scenarios from high to low growth so we can plan ahead for different possibilities. This approach guides our decisions on where and when to reinforce or upgrade the network, ensuring you continue to receive reliable electricity at the lowest possible cost. Figure 4.1 summarises where we get our information and how that affects our planning.

Population and growth patterns

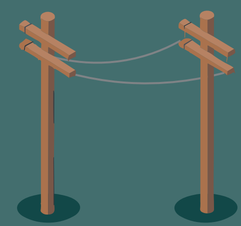
- Population and household projections obtained from Stats NZ
- Local district schemes and community plans from councils
- Notified changes in land use designations
- Known commercial, residential, and industrial developments

Technology and behaviour changes

- Emerging technology adoption, such as EVs, heat pumps, and solar panels
- Customer behaviour changes affecting when and how electricity is used
- The impact of energy efficiency improvements

Historical experience

- Historical electrical demands across our network
- Historical extreme movements in temperature and rainfall where this affects peak demand
- Trends in how different customer groups use electricity



Demand management impact

- Non-network solutions such as demand management and flexibility services
- The effect of our ripple control systems on peak demand
- Potential future flexibility services that could reduce peak loads

Figure 4.1 Inputs into our forecast demand model

Projected regional growth patterns and regional demand forecasts

Our network continues to undergo steady growth across the three main planning areas. Growth varies significantly between regions because of changes in demographics and regional characteristics. The Waimakariri area, particularly Rangiora, Kaiapoi, Pegasus, and Woodend, experiences the strongest growth due to residential subdivision activity and commercial development. The Hurunui and Kaikōura districts show more moderate but steady growth driven by tourism, lifestyle properties, and agricultural intensification.

4.4.2 Making the most of the network we have

Before we build new infrastructure, we look for smarter ways to manage the network we already have. This approach helps us defer expensive projects, keeping your costs down while still meeting your power needs.

Using load control to manage peak demands

We use ripple control to manage peak demand – those times when everyone wants power at once. By managing when certain appliances draw electricity, we can alleviate network constraints, defer capital investment, and reduce transmission charges. All of these translate into lower costs for you.

The introduction of the Upper South Island Load Control system has resulted in a flat load profile for the upper South Island transmission system. We also use additional controls to manage individual GXP and zone substation peaks. In particular, we actively manage the Amberley and Ludstone zone substation loads through winter peak periods, and the Kaikōura load during maintenance outages. This active management means we can maintain security of supply without immediately building expensive new capacity.

We are also exploring new ways to encourage electricity use at night, when demand is lower, by reviewing how we structure our electricity prices.

Flexibility services

Under our Network Transformation Plan, we are developing a Demand-Side Management strategy that will describe:

- our role in network flexibility
- how market responses may be contracted in future to provide for demand-side management beyond 300 Hz ripple control
- how to best promote competition in, reliable supply by, and efficient operation of the New Zealand electricity industry for the long-term benefit of consumers.

Distributed energy resources

We are committed to solutions that do not always require building new power lines or substations. By supporting distributed energy resources, such as solar panels, battery storage, and energy-saving measures, we can help meet growing demand in a smart and sustainable way. These resources allow us to delay big network investments, keep costs down, and increase the resilience of our electricity supply.

For example, in the Amuri area, where demand is already high, using renewable energy could help us meet the community's needs without overloading the network. During this reporting period, we plan to invite a range of proposals from the market to find the best non-network solutions. This approach will help us deliver safe, reliable, and affordable electricity while supporting sustainability.

We have already undertaken a formal process to find industry partners that might be able to address our network constraints via non-network solutions. We produced Request for Information documentation that outlined our requirements and offered businesses the chance to address those constraints. While none of the specific solutions were selected for immediate deployment, we have built relationships with potential partners and gained valuable insights into what might work in future. This keeps us open to new, potentially more cost-effective ways of meeting your power needs.

4.4.3 What this means for our investment decisions

These forecasts drive where and when we invest in network upgrades. They help us identify areas where network or equipment constraints will arise due to anticipated growth during the AMP planning period. For you, this means we are proactive rather than reactive. We aim to have infrastructure in place before you experience reliability problems.

We also explicitly consider how uncertain but substantial individual projects or developments affect our load forecasts. For major developments where timing is uncertain, we model different scenarios to understand the range of possible outcomes and plan accordingly. This adaptive approach means we can adjust our investment timing as these developments progress from potential to actual.

We regularly update these forecasts and review them against actual demand to refine our accuracy. This continual improvement process means we can adjust our investment plans as conditions change, avoiding both under-investment (which leads to outages) and over-investment (which wastes your money).

The impact of demand management initiatives and non-network solutions is explicitly factored into our forecasts. As we deploy more flexibility services and customers adopt distributed energy resources like solar and batteries, we adjust our demand projections accordingly. This integration maintains that our network investment decisions reflect the full range of tools we use to meet your electricity needs.

4.5 Investing in network intelligence

We are investing in technology that helps us find and fix problems faster, restore your power more quickly, and make smarter decisions about where to invest. These technologies work behind the scenes to improve your service without requiring you to do anything differently.

4.5.1 Automated switching

We are installing automation on ring main unit switchgear across the network. This allows specific switchgear to remotely switch electricity circuits, rapidly reconnecting electricity supply to customers who are experiencing outages. Instead of waiting for a crew to drive to a switching location, power can be restored from a different route automatically or with the push of a button in the network control room.

4.5.2 Fault detection

We have installed line fault indicators on our subtransmission lines, which can be used to more accurately identify the location of faults. These sensors tell us precisely where a problem is on the line, getting our crews to the right spot quickly.

Together, these technologies mean shorter outages and faster restoration times for you without the cost of building duplicate infrastructure.

4.6
Changes to our plan since last year

Networks are not static, and neither are our plans. We continually refine our approach based on new information, changing conditions, and opportunities to deliver better value. Table 4.1 describes what has changed since our last AMP, and why it matters to you.

Table 4.1 Planning improvements

Project	What has changed	Why it matters
Smarter connection route Coldstream to Fernside	We have modified the route for the new connection from Coldstream zone substation to link into our existing Southbrook–Burnt Hill line in the Fernside area, rather than running all the way to Southbrook substation.	This aligns better with Transpower's long-term plans and increases the overall capacity of the network without building as much new infrastructure. For you, it means the same reliability outcome for less cost.
Low-cost duct installation Woodend Bypass	We have allocated budget to install empty underground ducts along the Woodend Bypass route during construction.	When we need to run high-capacity cables through this area in future (as Woodend and Pegasus continue growing), we will not need to dig up roads or negotiate complex installations. The route will be ready and waiting. This approach could save hundreds of thousands of dollars compared to retrofitting later.
Strategic switching stations Ashley and Waipara	We are building new switching stations near Ashley and Waipara rather than adding bays to the existing GXP substations.	This gives us flexibility to make multiple connections without space constraints or expensive modifications to Transpower's substations. It is a more cost-effective way to build a flexible, resilient network.
Right-sized solutions Waipara–Amberley line upgrade	We have reduced the scope of the Waipara–Amberley line upgrade to avoid installing much heavier, higher-capacity conductor.	Heavier conductor would require replacing many existing poles because they could not handle the increased weight and clearance requirements. By right-sizing the upgrade to what is actually needed, we are saving significant costs while still delivering the capacity required. It is about matching the solution to the actual need, not over-building.
Practical resilience Hanmer diesel generation	We are installing backup diesel generation in Hanmer rather than building a second high-voltage line through challenging alpine terrain.	The Hanmer community has experienced frustrating outages, often caused by weather damage to the single line serving the area. Building a second line through mountains would be enormously expensive, and that cost would ultimately fall on all customers. Backup generation delivers the resilience Hanmer needs at a fraction of the cost.

4.7
How we prioritise projects

When deciding which network improvement projects to invest in, we carefully weigh a range of important factors. Our goal is to make sure every decision supports a network that is reliable, affordable, and safe for our customers and our wider community.

We listen to what our customers expect from us, manage any potential risks, work closely with other organisations, and keep our long-term plans and values at the heart of every choice we make. This balanced approach helps us allocate our resources to the projects that matter most, so we can manage immediate needs while also delivering on our vision for a sustainable and resilient network. Table 4.2 outlines our prioritisation factors for capital expenditure.

Table 4.2 Capital expenditure project prioritisation factors

Prioritisation factors
Primary driver(s) for the project
Impact on consumers if the project does not proceed or is deferred
Cost and funding implications
Alternative non-traditional solutions
Planning uncertainties
Consumer-driven projects for new connections or upgrades
Future network and company strategic alignment
Local authority and NZTA projects
Consumer expectations
Compliance, health, safety and the environment
Meeting service levels such as SAIDI, SAIFI, and security of supply
Cost-benefit analysis

Amberley zone substation

4.8 Our development strategy and major projects

We have developed a network development strategy built around five key commitments to you:

Enable and support regional growth
As North Canterbury grows, your electricity supply will keep pace.

Provide appropriate security of supply
Your power will be reliable, with backup systems ready when needed.

Facilitate continual improvement in network reliability
We are continually working to reduce the frequency and duration of outages.

Standardise subtransmission and distribution assets
Using standard designs and equipment keeps costs down and makes maintenance more efficient.

Facilitate consumer-driven technology adoption
Whether it is solar panels, EVs, or batteries, our network will support your choices.

Figure 4.3 Our major projects over the next 10 years

4.8.1 Major projects over the next 10 years

Over the next 10 years, we have a number of major projects planned to reinforce and upgrade our network. While some of these projects are larger and may mean a noticeable investment in certain years, we carefully balance these with ongoing smaller works to keep costs fair and deliver the best outcomes for our community.

Figure 4.2 shows our proposed long-term network development across North Canterbury, highlighting the major projects planned over the next decade and where they will strengthen your electricity supply.

Table 4.3 summarises all major projects across our network for the 10-year planning period, showing when work will occur and how we are balancing investments across the years.

Table 4.2 Major projects across North Canterbury over the next 10 years

Supporting these major investments are tactical reinforcement projects – smaller, targeted improvements that address specific local constraints, improve reliability, and help us defer more expensive upgrades.

Through these efforts, our aim is to provide a reliable, affordable, and sustainable energy supply – keeping safety and community benefit at the heart of everything we do.

Waimakariri River

4.9 Waimakariri district: meeting rapid growth

The area has seen rapid growth, including new subdivisions, new businesses, and more traffic on the roads, and all of it needs reliable electricity.

The Waimakariri area sits close to Christchurch, making it an attractive place for families and businesses. The development of the Christchurch Northern Motorway has accelerated this growth. For our electricity network, this means rapidly increasing demand, particularly in summer when hot weather increases the use of air conditioning and irrigation. Figure 4.3 illustrates our subtransmission network in Waimakariri.

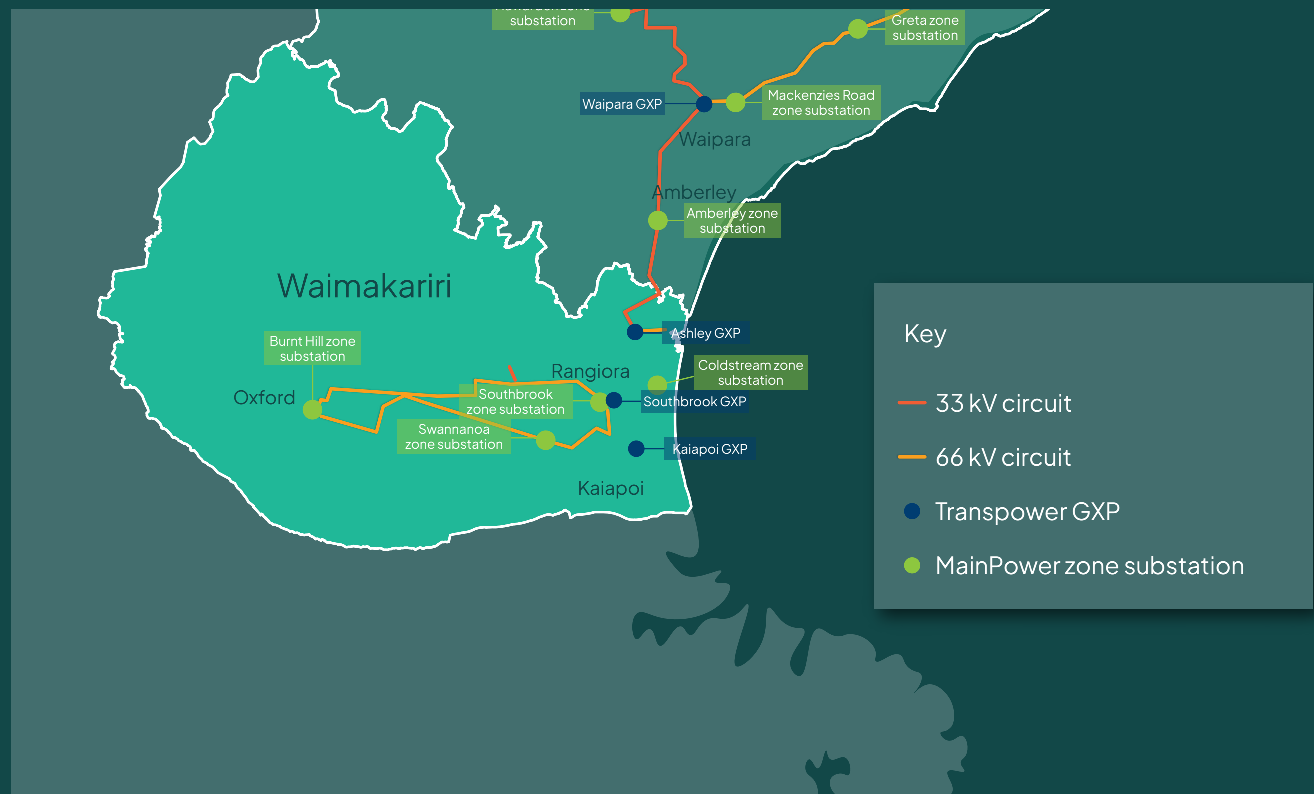


Figure 4.3 Waimakariri subtransmission network

4.9.1 The challenge we are addressing

Our current network is reaching its limits. Without action, you would start experiencing more frequent and longer outages as the network struggles to meet demand in key growth areas.

Table 4.4 Constraints on the Waimakariri network

Major issues	Proposed solution
The Ashley GXP has a "Grid Direct" single major consumer and cannot be restored within 15 seconds.	• We recognise this as a gap in the Security of Supply Standard and have discussed and agreed this configuration with the single consumer supplied via this site.
Southbrook, Burnt Hill, Swannanoa, and Kaiapoi have limited ability to achieve Transpower's load requirements during a half-bus outage.	• Construct the Coldstream 66/11 kV zone substation. • Develop long-term 66 kV interconnection capacity between Waipara, Southbrook, and the future Coldstream zone substation.
Southbrook and Kaiapoi 11 kV substations are forecast to exceed security-of-supply capacity in the short to medium term.	• The construction of Coldstream zone substation, along with tactical reinforcement projects, will allow load to be transferred to Ashley and Swannanoa zone substations to offload Southbrook and Kaiapoi 11 kV.
Residential and commercial growth in the Rangiora, Woodend, Ravenswood, and Pegasus areas is driving the need for a new zone substation east of Rangiora.	• The Coldstream 66/11 kV zone substation programme incorporates a series of sub-projects designed to provide additional capacity in these high-growth areas.

We also face coordination challenges with Transpower. During certain maintenance situations at Southbrook, there are limits on how much power we can draw. We have addressed this through implementation of a Special Protection Scheme that allows critical maintenance to be undertaken while managing network risks, and through our coordination with Transpower to allow for large capacity injections into the Waimakariri district.

West Eyreton

4.9.2 Our solution: the Coldstream zone substation project

Rather than simply upgrading existing substations (which would provide temporary relief but not address long-term growth), we are building new infrastructure strategically placed to serve growing areas.

The centrepiece is a new zone substation at Coldstream, east of Rangiora, along with new 66 kV lines to connect into the existing network. This project represents a significant investment in the region's electricity future, scheduled for construction between FY26 and FY31. Figure 4.4 below shows the Coldstream zone substation program timeline.

How are we building it

We are taking a staged approach to manage costs and deliver benefits progressively. You will see improvements before the whole project is finished, and we can adjust our plans as we learn and as conditions change.

Stage 1 – Design and early works

We are designing the route for the new high-voltage lines, securing easements, and obtaining necessary consents. This includes coordination with landowners, the Council, and other stakeholders to find routes that minimise disruption. Importantly, we are also building the first section of the line from Ashley at a lower voltage (11 kV initially) to provide immediate relief to growing areas like Ravenswood while the rest of the project is under construction.

Stage 2 – Build Ashley to Coldstream connection

We will construct the high-voltage line from Ashley to the new Coldstream site. Initially, parts of this will operate at 11 kV to support local areas, then be energised at full 66 kV when the substation is commissioned.

Stage 3 – Build Coldstream zone substation

The new substation will be designed in detail and constructed. This is where the high-voltage power (66,000 V) is transformed down to the 11,000 V used in local distribution. The substation will have full backup capability – if one transformer fails, the spare can take over immediately, keeping your power on.

Stage 4 – Build subtransmission circuit to provide N-1 supply to Coldstream zone substation

The final stage completes the project by building a connection from Coldstream to tie into our existing Southbrook–Burnt Hill line in the Fernside area. This creates a ring of supply routes, meaning power can come from multiple directions. If one line has a fault, power flows around the ring from the other direction.

Figure 4.4 Coldstream zone substation program timeline

4.9.3 Supporting projects to bridge the gap

Island Road feeder extension

Bringing more capacity to southeast Kaiapoi where new developments are connecting

Rangiora North feeder bypass

Installing new cable to address a bottleneck on East Belt and Coldstream Road

Fernside network reconfiguration

Transferring the Fernside area onto more reliable supply from Southbrook

Automation of switchgear

Installing remote-controlled switches across the network so we can restore your power faster during faults

A detailed list of further supporting projects is provided in Table 4.5

Coldstream

Table 4.5 Waimakariri area reinforcement projects (FY27–FY35)

Financial year	Project name	Project details
FY27	Island Road feeder extension	Extend an 11 kV feeder on Island Road to address capacity constraints and meet increasing demand requirements in southeast Kaiapoi.
FY27	Rangiora North feeder	Install a new cable to alleviate a capacity limitation on the corner of East Belt and Coldstream Road.
FY27	Fernside reconfiguration	Undertake multiple small overhead network upgrades to allow reconfiguration of the Fernside network to enable it to be transferred onto a more reliable supply from Southbrook zone substation.
FY27	Kaiapoi switchboard replacement	Replace the switchboard for the new Kaiapoi GXP substation.
FY27	Rangiora West overhead feeder	Construct an overhead link down Lehmans Road to strengthen the supply to north-western Rangiora to support further load growth.
FY27	X52–X55 22 kV link	Install new overhead lines and circuit breakers to allow connection of three spur lines close to the Waimakariri River, increasing security of supply.
FY29	Lineside Road feeder creation	Extend an existing 11 kV feeder to support the growing load at Kaiapoi GXP substation.
FY29	Burnt Hill–Swannanoa phasing reconfiguration	Reconfigure the 11/22 kV network to remove phase shifts within the network – reducing switching risk and improving network load transfer options.
FY29	Mandeville area voltage improvement	Install a regulator and reconductor sections of the line between Kaiapoi and Mandeville to improve the voltages in that area of the network.
FY30	Bellgrove feeder	Install a high-capacity feeder cable within the Bellgrove subdivision to provide a high-capacity supply path into North Rangiora.
FY30	Burnt Hill X53–X56	Upgrade the 22 kV network around Harmans George Road, Inland Scenic Route 72, and Thongcaster Road, improving network resilience and reliability.
FY31	Kaiapoi 8376 to S11 link	Create an interconnection between 11 kV feeders in Kaiapoi to increase alternative supply options.
FY31	Ashley–Leithfield 11 kV link	Install a cable and reconductor line along Rangiora Leithfield Road to allow additional supply into the Leithfield region, improving security of supply.
FY31	High Street cable	Install a new cable between High Street and East Belt to connect spur lines, improving resilience and security of supply.
FY31	Mandeville area voltage improvement – Tram Road and Whites Road	Reconductor existing overhead conductor along Tram Road and Whites Road.
FY32	Blackett Street cable	Install a new high-capacity feeder cable along Blackett Street to allow a high-capacity backup supply from the (future) Coldstream zone substation into central Rangiora.
FY32	Mandeville area voltage improvement – South Eyre Road	Reconductor a section of line along South Eyre Road.
FY33	Barkers Road links	Install a new 11 kV overhead line and a switching device along Barkers Road to allow for security of supply.
FY33	Birch Hill link – Stage 1	Install a new line and reconductor an existing line along Birch Hill Road to link two spur lines supplied from Burnt Hill and Swannanoa zone substations, improving security of supply.
FY34	Oxford German Road link and switchgear	Link the Ashley Gorge feeder to X57 on German Road to improve security of supply and reliability.
FY34	Birch Hill link – Stage 2	Reconductor existing overhead line to allow additional customers to be supplied via the new connection during outages on the adjacent feeder.
FY35	West Belt undergrounding	Underground the south end of West Belt to remove ageing overhead assets and improve network connectivity.
FY35	Kaiapoi Stone Street undergrounding	Underground the existing 11 kV overhead conductor to improve security of supply and reduce risk.

4.9.4 What you can expect over the next few years

Figure 4.5 outlines the improvements that are planned over the next 10 years and what this means for you.

In the short terms 2–3 years

- Tactical reinforcement work in your area with some planned outages (scheduled at convenient times where possible)
- Visible construction as we start building the Ashley–Coldstream line
- Continued reliable supply as we actively manage the network through this growth period

In the medium term 3–5 years

- Commissioning of Coldstream zone substation, providing stronger, more reliable supply to the eastern Waimakariri area
- Reduced voltage fluctuations in growing areas
- Faster restoration times during faults as new switching capability comes online

In the long term 5–10 years

- A fully meshed, resilient subtransmission network with multiple supply routes
- Capacity for continued growth in Rangiora, Woodend, Pegasus, and surrounding areas
- Improved reliability across the whole Waimakariri district

Figure 4.5 Coldstream programme summary

Rangiora

Hanmer Springs

4.10 Hurunui district: supporting the rural and alpine communities

The Hurunui district stretches from the Waimakariri River to the alpine townships of Hanmer Springs and Culverden, encompassing farming communities, forestry operations, and tourism destinations. If you live here, you know that electricity supply faces unique challenges – longer distances, more exposed lines, and weather that can range from north-west gales to heavy snowfalls. Figure 4.6 shows our network in Hurunui.

Figure 4.6 Hurunui subtransmission network

You have told us through our surveys that reliability in Hurunui could be better. We have heard you, and we are responding with targeted investments designed to address the specific challenges of this region.

Table 4.6 Hurunui area network constraints

Area	Major issues	What are we doing about it
Amberley	Load exceeds security-of-supply class rating at Amberly (N-1). Peak load cannot be supplied in the event of an outage.	• Supply will be switched to Ashley GXP to provide the majority of the forecast load. • Load will be transferred to Mackenzies Road zone substation to minimise the capacity shortfall.
Greta	Peak load cannot be supplied at Greta in the event of a transformer outage.	• Planned reinforcement projects will link the Greta area to the Cheviot zone substation to provide switchable backup.
Cheviot	Peak load cannot be supplied at Cheviot in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV line upgrade will increase the capacity to supply into the northern Cheviot area during peak summer loads. • The Cheviot area will be linked to the Greta zone substation.
Leader	Peak load cannot be supplied at Leader in the event of a transformer outage.	• The Cheviot–Kaikōura 66 kV line upgrade will increase the capacity to supply into the northern Cheviot area during peak summer loads. • There are currently no plans to provide full backup within the planning period.
Hawarden	Peak load cannot be supplied at Hawarden in the event of a transformer outage. Only a single line feeds the substation.	• The Hawarden zone substation is planned to be rebuilt as a dual transformer substation. • Reinforcement projects will increase load-transfer capacity from Mouse Point. • We are exploring non-network options in this area.
Mouse Point	Peak load cannot be supplied at Mouse Point in the event of an outage. Switching the supply following a 33 kV cable fault requires more than 45 minutes.	• Emergency control will be implemented on irrigation loads to allow all but irrigation loads to be restored on a single 13 MVA transformer. A spare 8 MVA transformer is held as a backup. • We are exploring non-network options in this area. • Summer cyclic ratings will be explored to maximise the contingency rating of the transformers. • The Mouse Point zone substation will be rebuilt.
Hanmer	Peak load cannot be supplied at Hanmer in the event of a transformer outage. Only a single line feeds the substation.	• Replace the Hanmer Springs zone substation. • We are exploring non-network options in this area. • The 33 kV line is being upgraded.

4.10.1 Major projects planned for Hurunui

Amberley zone substation upgrade — FY26–FY27

The new Amberley zone substation is capable of operating at higher voltages when we eventually upgrade the subtransmission system. The substation will operate at 33 kV until the 66 kV subtransmission line upgrade project is completed (expected FY34–FY36).

By building the substation now for 66 kV operation later, we are planning ahead and avoiding the need to rebuild again in the future. This approach saves money by getting the capacity right the first time.

Hanmer Springs zone substation upgrade — FY28–FY31

The Hanmer community raised concerns about outages, and we have listened. The challenge at Hanmer is unique: a single line serves the township through challenging alpine terrain prone to weather damage.

Our solution has two parts that work together to deliver resilience:

- The Hanmer Springs subtransmission line upgrade was completed in FY26, with stronger conductor and structures. We have put mitigations in place to reduce the impact of potential natural hazards where possible.
- We are rebuilding the Hanmer Springs zone substation to increase capacity, provide backup transformer capacity, replace end-of-life assets, and importantly, install backup diesel generation to maintain supply during extended line outages.

This pragmatic approach delivers the resilience Hanmer Springs needs without the enormous cost of building a second line through the mountains – a cost that would ultimately be borne by all customers across our network.

Hanmer Springs

Other Hurunui projects

As well as the major projects listed above, we have a number of reinforcement projects planned (Table 4.7). These smaller projects will help us meet the needs of the Hurunui district.

Table 4.7 Hurunui district reinforcement projects (FY27–FY36)

Financial year	Project name	Project details
FY27	Mouse Point–Hawarden upgrade	A new section of 11 kV line will be installed along SH7 north of the Hurunui River to enable increased remote load-transfer capacity between Hawarden zone substation and Mouse Point zone substation.
FY27	Cheviot–Greta 22 kV link	An existing section of overhead 11 kV line will be reconductored and uprated to 22 kV and a 22/11 kV transformer installed to allow a backup supply for Greta zone substation and a partial backup supply for Cheviot zone substation.
FY27	Lawcocks Road reconfiguration	The main 11 kV circuits that supply Amberley township will be reconfigured, increasing reliability and remote control of network operations.
FY30	Greta–Hawarden upgrade	An existing section of overhead 11 kV line will be reconductored and uprated to 22 kV. A 22/11 kV transformer will also be installed to allow a backup supply for Greta zone substation and a partial backup supply for Cheviot zone substation.
FY32	Cheviot–Leader upgrade	The 11 kV conductor between Parnassus and Waiau East Road and Waiau West Road will be upgraded, improving the security of supply for Cheviot and Leader zone substations.
FY33	Reinforce P35 to H41 along SH7	3.6 km of new 11 kV overhead line along SH7 north of the Hurunui River will be installed to improve load transfer capacity and security of supply.
FY33	Lawcocks Road cable	The existing double circuit 11 kV line that extends along Lawcocks Road will be undergrounded to improve capacity and improve security of supply.
FY34	Reinforce P25 South across the Hurunui River	A new section of overhead line will be installed between McKays Road and Bishells Road across the Hurunui River, increasing security of supply between spur circuits.
FY35	Amberley Beach alternative supply	A new 11 kV line along Hursley Terrace Road and Crosses Road will be installed to improve security of supply between spur lines.
FY36	Mouse Point feeder security	A new feeder from Mouse Point zone substation to the Culverden township will be installed to provide security of supply for the existing Culverden township loads (P25 and P35 feeders) and increase transfer capacity to Hawarden to meet the Security of Supply Standard.

4.10.2 What this means for you

If you are in Amberley, you will see construction of the new substation and can expect improved reliability once it is commissioned. If you are in Hanmer Springs, you will experience fewer extended outages thanks to the line improvements and backup generation. And across the wider Hurunui district, the tactical reinforcement projects will address specific local constraints and improve voltage quality.


Lochiel zone substation

Kaikōura

4.11
Kaikōura district: building resilience

The Kaikōura region has unique challenges. The 2016 earthquake reminded us all how vulnerable infrastructure can be, and the coastal and alpine environment means our assets face salt spray, seismic risk, and challenging terrain. Building resilience here is about learning from that experience and preparing for future events. Figure 4.7 shows the dual subtransmission network that supplies the Kaikōura district.

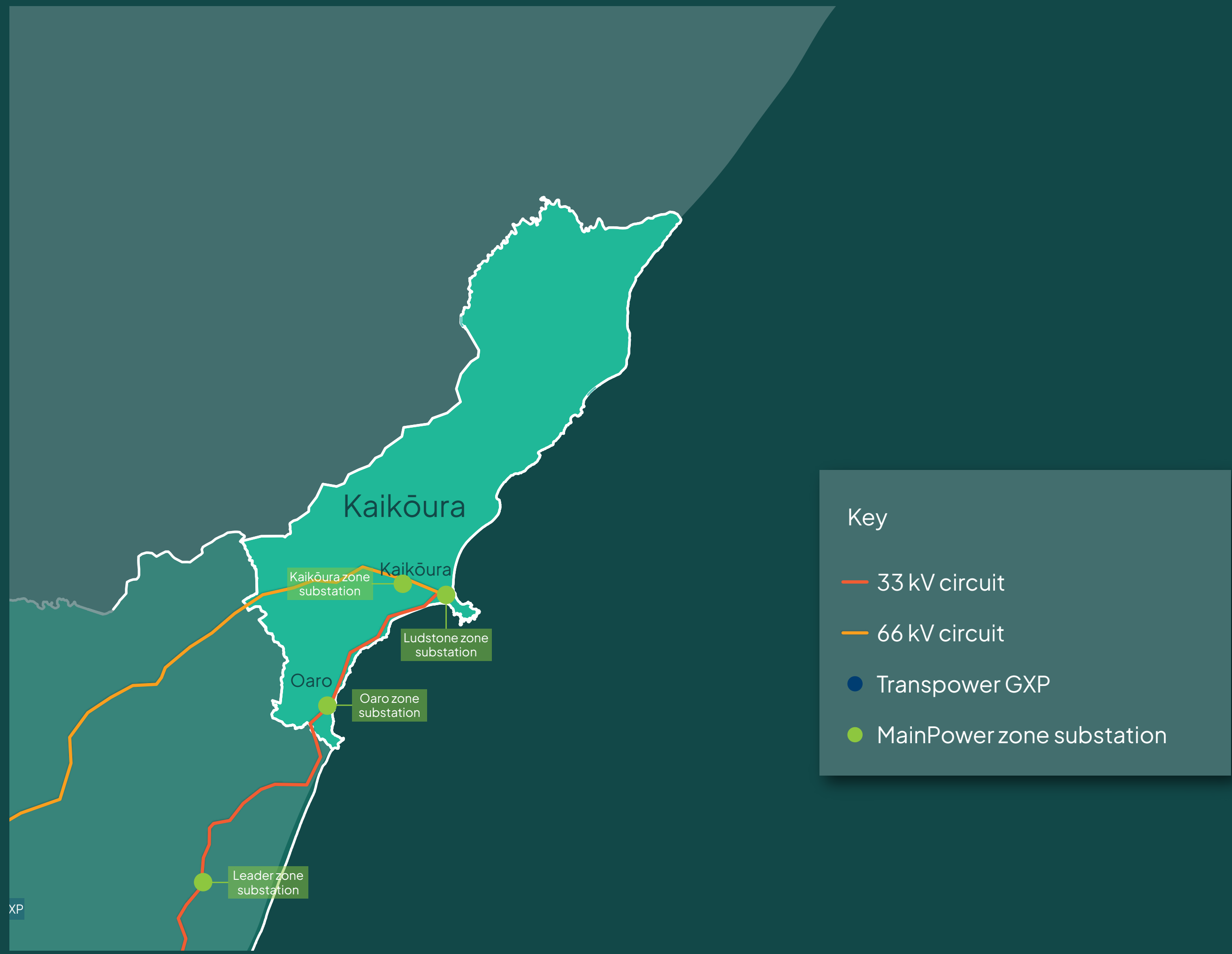


Figure 4.7 Kaikōura district subtransmission network

You have told us through our surveys that reliability in Kaikōura could be better. We have heard you, and we are responding with targeted investments designed to address the specific challenges of this region. Table 4.8 sets out the major issues that constrain the supply in the Kaikōura region.

Table 4.8 Kaikōura constraints

Area	Major issues	Growth and security projects
Kaikōura township and areas down the Kaikōura Coast to Waipara	• Peak load exceeds the nameplate continuous rating of a single power transformer under N-1 operation.	• We have developed a new transformer modelling tool to manage Ludstone peak load.
	• The required 45-minute switching time for a fault cannot be achieved. • The backup N-1 capacity from Waipara GXP has reached full capacity.	• We are upgrading the existing 33 kV subtransmission system from Cheviot to Kaikōura to 66 kV.

Kaikōura

4.11.1 Major projects planned for Kaikōura

Cheviot to Kaikōura 66 kV subtransmission line upgrade — FY26–FY28

This project, already underway, is upgrading the existing 33 kV subtransmission system from Cheviot to Kaikōura to operate at 66 kV. This means more capacity and better security of supply for the whole Kaikōura coast.

The key project elements include:

- removing the voltage transition point to allow the entire line from Waipara to Kaikōura to run at 66 kV
- relocating and rebuilding the ageing Oaro substation to a new, more suitable location
- building a new bay at Kaikōura substation so two 66 kV circuits can connect directly, creating N-1 security (if one circuit fails, the other maintains supply)
- replacing structures carrying the line over the Raramai Tunnel to provide a more resilient solution.

Kaikōura 66 kV zone substation upgrade — FY29–FY32

Following the line upgrade, we will upgrade the Kaikōura zone substation itself, including replacing the old Ludstone substation and consolidating operations at one modern facility.

The project stages are as follows:

- **Design and consenting:** detailed planning for the site, network connections, and necessary approvals
- **Construction and commissioning:** building and bringing the new substation into service

Once complete, we will decommission the Ludstone site, consolidating operations at the upgraded Kaikōura location. This improves efficiency and reduces the number of sites we need to maintain.

Other Kaikōura reinforcement projects

Other Kaikōura reinforcement projects are described in Table 4.9.

Table 4.9 Kaikōura district reinforcement projects (FY27–FY32)

Financial year	Project title	Description
FY27	Beach Road cable installation	An existing section of 11 kV cable will be replaced along Beach Road in Kaikōura to ensure capacity for future demand requirements for customers north of Ludstone Road.
FY30	Ocean Ridge feeder upgrade	A new cable will be installed extending south from the future Kaikōura zone substation along Mt Fyffe Road towards SH1, allowing connection with an existing feeder, improving capacity and security of supply to the Ocean Ridge subdivision.
FY31	North Kaikōura feeder cable	A new overhead 11 kV overhead line will be constructed along Rorrisons Road, and the existing overhead line along Hawthorne Road will be reconductored to provide additional capacity for the existing 11 kV line on SH1 north of Kaikōura.
FY32	Seaview feeder extension	A new 11 kV cable will be installed extending south along Mt Fyffe Road and into the Seaview subdivision to provide additional capacity and security of supply.

These tactical projects address specific local constraints and growth areas, particularly in newer subdivisions developing around Kaikōura township.

4.11.2 What this means for you

We will be upgrading key sections of the network, which will increase capacity and reduce the risk of power outages, and if the power does go out, we will be able to restore service more quickly. Through these investments, we are strengthening the region's energy resilience and giving you greater peace of mind about your electricity supply.

Kaikōura

4.12 Looking further ahead

Waipara to Amberley 66 kV subtransmission line upgrade

Following the completion of the new Amberley zone substation, we will upgrade the existing 33 kV subtransmission line between Waipara and Amberley to operate at 66 kV.
This completes the long-term voltage standardisation strategy for the Hurunui district, improving capacity and reliability while simplifying network operations.

Replacement of skid-mounted substations

Several of our smaller substations are temporary installations that will need permanent replacements. These temporary facilities have served their purpose well, but as the network evolves, we need to plan for proper permanent infrastructure that will deliver reliable service for decades to come.

Potential redevelopment of Bennetts zone substation

As the Woodend and Pegasus areas continue to grow, we are investigating whether the existing Bennetts substation will need redevelopment or replacement to handle future demand.
This investigation work allows us to understand the options and make informed decisions when the time comes.

Mouse Point and Hawarden zone substation upgrades

Both substations serve important agricultural and residential areas and will eventually require upgrades to meet growing demand and replace ageing assets. By investigating these needs now, we can integrate them into our long-term investment plans efficiently.

Further voltage standardisation

Our long-term strategy aims to standardise our subtransmission network at 66 kV across North Canterbury. This reduces the complexity of operating mixed-voltage systems, improves efficiency, and makes it easier to manage the network as it grows. As substations reach the end of their life, we rebuild them for 66 kV operation, progressively moving towards this goal.

These longer-term projects demonstrate our commitment to planning ahead. By starting investigations early, we avoid rushed decisions and deliver better value for you. When these projects eventually proceed, they will be well-thought-out and cost-effective because we have taken the time to understand the options and develop the best solutions.

4.13 Continual improvement and adaptive planning

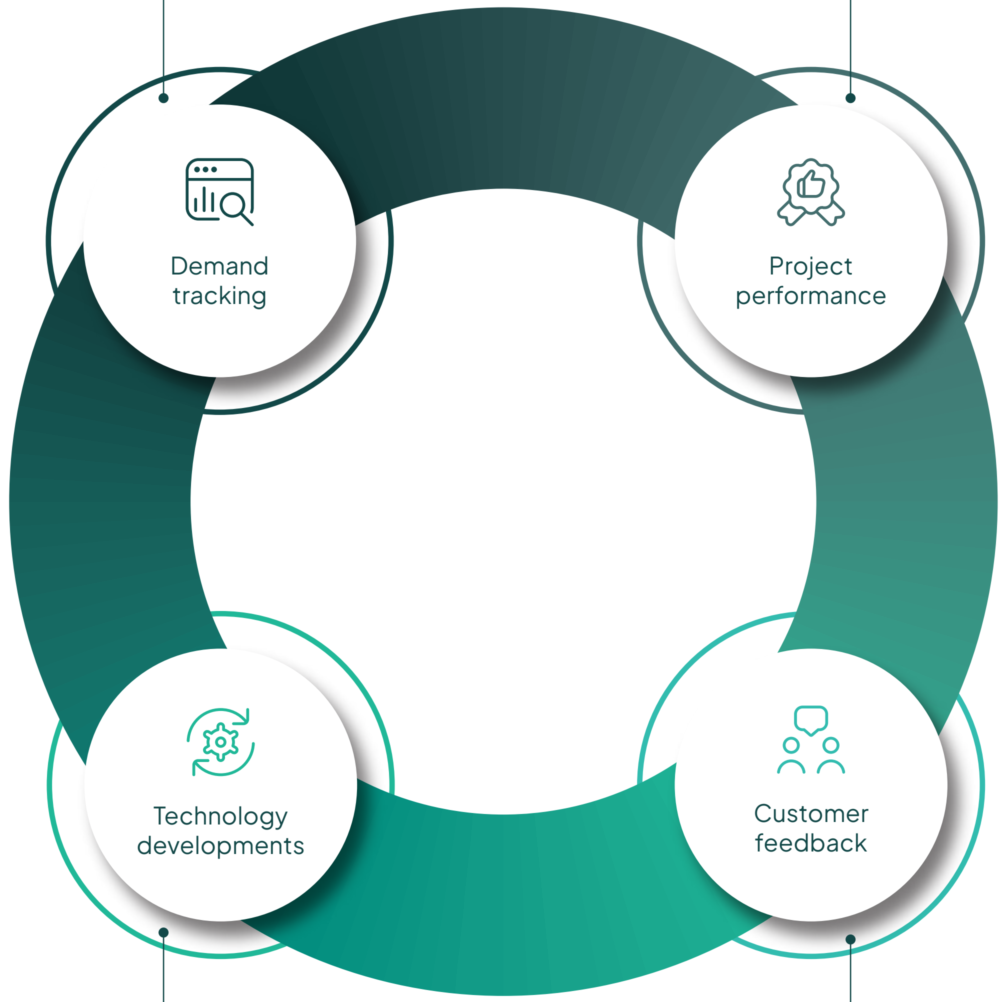
Network planning is not a one-time exercise. As North Canterbury evolves, as new technologies emerge, and as your needs change, we adapt our plans accordingly.

4.13.1 Monitoring and review

Every year, we review our network development plans against actual outcomes. We compare our demand forecasts to actual load growth, assess the performance of completed projects, and adjust our forward plans based on what we learn. This continual improvement cycle, (Figure 4.8) means we are always refining our approach to deliver better outcomes for you.

We closely monitor actual demand growth against our forecasts at each substation. If growth is faster or slower than expected, we adjust the timing of future projects accordingly.

After major projects are completed, we evaluate whether they delivered the expected outcomes. These lessons learned inform how we approach future projects.



The electricity industry is changing rapidly. We actively monitor emerging technologies and approaches that might offer better solutions for meeting your needs. If new options become available that are more cost-effective than our planned approach, we adjust our plans.

Your experience of our network is the ultimate measure of success. We use customer satisfaction surveys, outage data, and direct feedback to understand where improvements are needed and prioritise our investments accordingly

Figure 4.8 Our continual improvement cycle

4.14 Scenario planning and adaptability

We recognise that the future is uncertain. Economic conditions, population growth patterns, and the pace of technology adoption can all vary significantly from our forecasts. That is why we use scenario planning to understand the range of possible futures and develop flexible strategies that can adapt as conditions change.

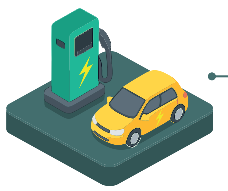
Our planning approach explicitly considers:

High-growth scenarios

What if residential development accelerates faster than expected? Our plans include options to accelerate project delivery if needed.

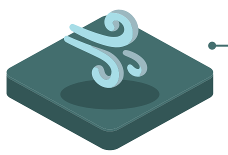
Economic uncertainty

What if economic conditions change and affect both customer demand and our ability to invest? Our prioritisation framework allows us to scale investment up or down while maintaining core reliability.



Technology disruption scenarios

What if EV adoption happens faster than forecast, or if battery storage becomes economically viable sooner than expected? We monitor these trends and have strategies to respond.



Climate resilience scenarios

What if extreme weather events become more frequent or severe? Our asset selection and route planning explicitly considers climate adaptation.

This adaptive approach means you can have confidence that our plans are robust to uncertainty. We are not locked into a fixed path; we will adjust as needed to continue delivering reliable, affordable electricity as your needs evolve.

4.14.1 Integration with broader asset management

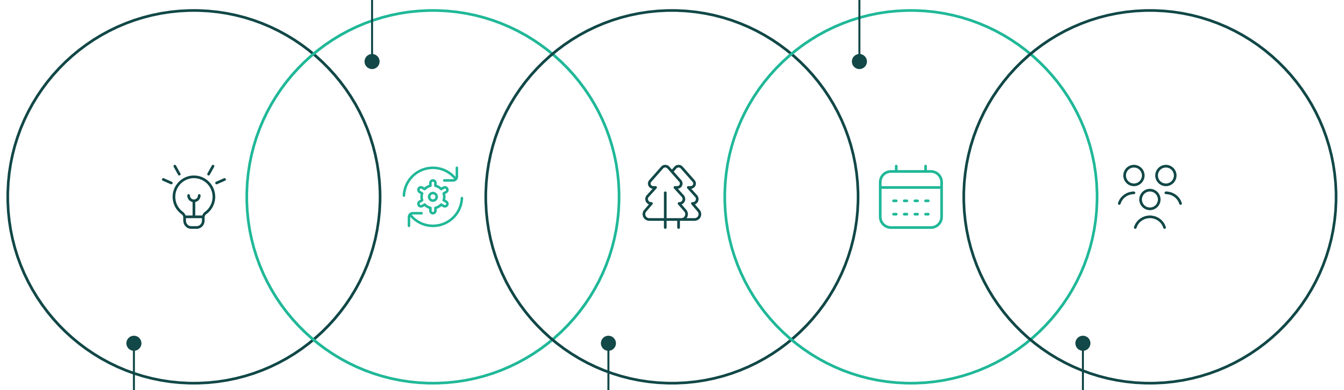
The long-term subtransmission network strategy sits within our broader AMP. The projects and investments described here are integrated with:

Asset replacement and renewal programmes

Our ongoing work to replace ageing assets before they fail

Network automation and control systems

Our investments in technology to restore your power faster when faults occur



Distribution network development

Our 11 kV and 22 kV distribution network plans, which deliver power from zone substations to your homes and businesses

Vegetation management

Our tree-trimming programmes that reduce the risk of outages from vegetation contact

Customer service improvements

Our programmes to improve how we communicate with you and respond to your needs

All these elements work together to deliver a network that meets your expectations for reliability, affordability, and service quality. The subtransmission strategy provides the high-capacity backbone, but it is only one part of the complete system that delivers electricity to your home or business.

4.14.2 What all of this means for you

After reading about substations, subtransmission lines, and planning processes, you might be wondering: what does all of this actually mean for me?

4.14.3 Reliable power when you need it

The investments described in this strategy translate directly into reliable electricity supply. When we upgrade a substation or build a new line, we are creating backup routes and additional capacity so that:

- your lights stay on, even when one part of the network has a problem
- your power quality remains stable, without annoying voltage fluctuations
- your electricity supply can handle future growth without requiring last-minute emergency upgrades.

Reliability is not something you notice until it is not there. Our goal is that you continue to not notice – your electricity simply works when you need it.

4.14.4 Fair and stable costs

Every investment we make ultimately affects your electricity bill. That is why cost-effectiveness is central to every decision we make. The strategies described in this document – coordinating with others, using demand management before building infrastructure, right-sizing our solutions – all aim to deliver the outcomes you need at the lowest reasonable cost.

By planning ahead and taking a long-term view, we avoid the expensive reactive upgrades that would cost you more. By coordinating with Transpower and local councils, we avoid duplicating infrastructure. By carefully prioritising projects, we spread major investments over time to avoid large bill spikes.

4.14.5 Support for how you want to use electricity

The network we are building will support your choices about how you use electricity. Whether you want to install solar panels, drive an EV, heat your home with a heat pump, or simply have reliable power for traditional appliances, our network will be ready.

We are not prescriptive about how you should use electricity; our role is to provide a flexible network that supports whatever choices you and your neighbours make. The capacity we are building and the flexibility we are creating mean you will not be constrained by the network.

4.14.6 Resilience for the future

Climate change and natural hazards are real risks for North Canterbury. The 2016 Kaikōura earthquake demonstrated how vulnerable our infrastructure can be. The resilience measures in this strategy – including backup generation in Hanmer, strengthened lines, N-1 security at key substations – all aim to maintain your power supply even when major events occur.

We cannot prevent earthquakes or storms, but we can build a network that recovers quickly and maintains supply to as many customers as possible during and after these events.

4.14.7 A network ready for your community's future

North Canterbury is growing and changing. New subdivisions, new businesses, and new ways of living all create demand for reliable electricity. The network development strategy described in this document positions us to support that growth.

When new subdivisions are built in Pegasus or Woodend, the network capacity will be ready. When new businesses open in Rangiora or Amberley, the power will be there. When the Hurunui district develops further, the infrastructure will support it. This forward planning means your community can grow and prosper without being held back by electricity supply constraints.

4.15
Your role and your voice

This strategy has been shaped by what you have told us through customer surveys, engagement sessions, and your daily interactions with our network. Your priorities – reliability, affordability, and service quality – are embedded in every decision we make.

As we implement this strategy over the coming years, we will continue to seek your feedback. Major projects will involve community consultation. We will report back regularly on our progress. And we will adjust our plans based on what we hear from you.

If you have questions about projects in your area, concerns about network performance, or ideas about how we could do things better, we want to hear from you. Visit mainpower.co.nz or contact us at 0800 30 90 80.

Your electricity network belongs to the community it serves. This strategy is our commitment to you that we will continue to invest wisely, plan carefully, and deliver the reliable, affordable electricity supply that powers your homes, businesses, and communities across North Canterbury.

Mt Alexander, Hawarden

Kaiapoi

5 Creating a sustainable network

This section brings together the investment programmes described throughout this AMP and shows you the financial commitments we are making over the next 10 years. We explain how we balance maintaining reliable service with managing your costs, and what drives the changes in our expenditure over time.

What you will find in this section

- Our total investment programme for the next 10 years
- How expenditure is allocated across different priorities
- What drives changes in spending over time
- How we deliver efficiency and value for money

5.1
Balancing reliability and affordability

Our goal is straightforward: keep your power reliable and affordable, now and into the future. We have developed a detailed plan for the next 10 years, making sure our network meets your needs and expectations while managing our spending carefully so that costs stay steady over time.

This allows us to deliver the reliable service you expect at the lowest possible cost, without compromising on safety or quality. By planning for the long term and focusing on sustainability, we are building a network that supports our community's wellbeing and future growth.

We put your needs first, thinking not just about today but about how we can best serve you for years to come. Our approach is designed to benefit everyone in the community, making sure our network is strong, safe, and ready for what is ahead.

5.2
Our 10-year investment programme

Over the next decade, we will invest approximately $521 million in maintaining, renewing, and improving your network. This investment responds directly to what you told us matters most: reliability, resilience, safety, and careful cost management.

5.2.1 Total network expenditure

Table 5.1 shows our total network expenditure over the next 10 years, broken down by the key investment categories explained throughout this plan.

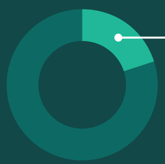
Table 5.1 Total network expenditure (FY27–FY36)

	Expenditure ($000)									
Category	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Major projects	15,932	12,018	10,404	12,041	12,597	8,003	9,270	9,180	5,670	5,750
Network reinforcement	3,441	3,480	3,760	3,787	3,484	3,565	3,667	3,009	3,266	3,350
Future networks	475	500	550	550	550	550	550	550	550	550
Replacement	14,708	15,335	15,823	15,823	15,823	15,823	15,823	15,823	17,000	18,000
Maintenance	9,110	8,733	8,961	9,349	9,503	9,657	9,793	10,103	10,428	10,428
Network operations	2,375	2,402	2,370	2,378	2,375	2,409	2,411	2,401	2,408	2,413
Non-network	2,835	2,366	2,046	2,626	1,814	1,739	1,690	2,820	1,620	1,440
Customer-initiated works	11,700	19,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Total	**60,576**	**64,034**	**49,914**	**52,554**	**52,146**	**47,746**	**49,203**	**49,884**	**46,941**	**47,930**

5.2.2 Understanding the investment categories

Figure 5.1 shows our total network expenditure over the next 10 years, broken down by the key investment categories explained throughout this plan. Let us explain what each category means for you and why the investment is necessary.

Major projects

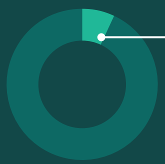


19%
of total expenditure
$101 million

These are the large infrastructure investments responding to regional growth, detailed in section 4. This includes new zone substations like Coldstream, major upgrades at Amberley and Hanmer Springs, and the Kaikōura resilience improvements. This investment creates capacity for new homes and businesses across North Canterbury, supporting your community's economic development.

The expenditure profile shows higher investment in the early years (FY27–FY31) as we deliver critical capacity projects, then moderating as these complete. Without these investments, network constraints would limit development and affect service quality in growing areas.

Network reinforcement

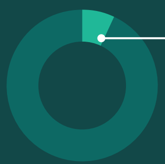


7%
of total expenditure
$35 million

These targeted improvements address reliability constraints and bottlenecks across the existing network. Examples include the Island Road feeder extension improving capacity in southeast Kaiapoi, the Rangiora North feeder bypass addressing East Belt bottlenecks, and Fernside network reconfiguration for more reliable supply.

This investment translates directly to fewer outages and faster power restoration when faults occur. It also includes switchgear automation, allowing remote operation that restores power to unaffected customers in minutes rather than hours.

Future networks

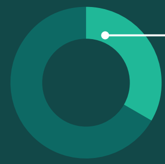


1%
of total expenditure
$5.4 million

This smaller but important investment prepares your network for emerging technologies: EVs, solar panels, battery storage, and smart home systems. We are investing in the monitoring, control, and communications infrastructure needed to manage a more complex, two-way power system efficiently.

Importantly, you told us not to invest speculatively in unproven technology. This modest programme focuses on proven infrastructure that supports customer choices without assuming rapid technology adoption.

Asset replacement and renewal



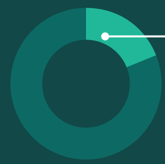
31%
of total expenditure
$160 million
(the largest category)

This is the systematic replacement of ageing assets before they fail, maintaining the reliability you expect. As explained in section 3, much of our network was built between the 1950s and 1980s, and substantial portions are now reaching the end of their design life.

Rather than allowing equipment to fail and cause outages, we proactively replace it based on condition and risk assessment. This approach costs less than reactive emergency replacements and delivers better reliability outcomes.

The expenditure increases from $14.7 million in FY27 to $20.7 million in FY36, reflecting the growing proportion of 1960s-era assets reaching replacement age over the decade.

Maintenance

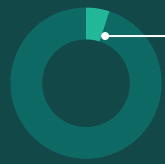


18%
of total expenditure
$96 million

Preventive care extends asset life and prevents failures. This includes regular inspections, vegetation management, routine servicing of equipment, and corrective work addressing emerging issues before they become problems.

Our maintenance programme is detailed in section 3 by asset category. This ongoing investment keeps equipment functioning reliably and safely, often deferring or avoiding replacement costs.

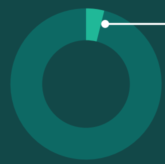
Network operations



5%
of total expenditure
$24 million

This is the day-to-day running of the network: responding to faults, switching operations, emergency callouts, and coordinating outages for maintenance and connections work. This also covers our network control centre operations, managing the real-time flow of electricity across North Canterbury.

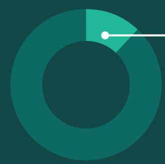
Non-network assets



4%
of total expenditure
$21 million

These are supporting assets like IT systems, vehicles, tools, property, and office equipment that allow us to operate the network efficiently. While not directly part of the electricity infrastructure, these assets are essential for planning, managing, and maintaining your network.

Customer-initiated works



15%
of total expenditure
$79 million

These are new connections for your property, upgrades to your service, and other work you request. In most cases, you pay directly for your portion of this work through connection charges, so it does not affect general network charges. We have included it here to show the total activity on the network.

Figure 5.1 Summary of investment categories

Hanmer Springs

5.3
What drives our investment

Several factors shape our investment programme and explain why spending changes over time.

5.3.1 Ageing asset replacement

The primary driver of this category of expenditure is the safety and reliability of the network. Our replacement programme ramps up from $14.7 million in FY27 to $18 million in FY36 as more 1960s-era equipment reaches replacement age.

5.3.2 Regional growth

North Canterbury is growing, particularly in the Waimakariri district. Rangiora, Kaiapoi, Woodend, and Pegasus are experiencing steady population increases and new business development. This growth drives the major projects programme, with $101 million invested in capacity increases over the decade.

The timing of these projects reflects forecast growth patterns. Coldstream and Amberley projects deliver in the early years (FY27–FY29) when capacity constraints are most acute. Later projects like Hawarden respond to longer-term agricultural intensification trends.

5.3.3 Resilience and climate adaptation

When we asked how you would want your lines charges invested, you allocated 24% of your preferred investment to resilience (section 1.2.1), recognising that climate change is bringing more frequent and severe weather events. Recent storms have tested our network, and we expect this trend to continue. Our resilience investments focus on strengthening critical infrastructure to withstand these challenges. This includes installing stronger pole specifications in exposed coastal areas, enhancing vegetation management through AI-powered risk assessment, and deploying automated switchgear that enables faster fault response. We are also improving our emergency response capability so that when severe weather strikes, we can restore power more quickly and keep our communities connected.

These investments are distributed across the major projects, reinforcement, and replacement categories throughout the 10-year period.

5.3.4 Technology and customer choice

While you told us not to invest speculatively in emerging technology (section 1.2.1), we must prepare the network for technologies customers are adopting: EVs, solar panels, and smart home systems.

The "Future Networks" programme ($5.6 million over 10 years) provides for the monitoring, communications, and control infrastructure needed to manage these technologies efficiently as adoption increases. This expenditure protects the value of your existing network assets as the electricity system evolves.

5.3.5 Regulatory standards and compliance

Electrical safety standards evolve over time, reflecting improved understanding of risks and new technologies. Our investment programme brings older parts of the network up to modern standards, particularly in areas of seismic risk and areas requiring enhanced protection systems.

Similarly, cybersecurity requirements for critical infrastructure are becoming more stringent. We are investing in protective systems for our SCADA and communications networks to defend against cyber threats.

5.3.6 Input cost pressures

Like all businesses, we face cost inflation. The specialised equipment we purchase (transformers, cables, poles, switchgear) has experienced significant price increases in recent years due to global supply chain pressures and commodity price movements.

Labour costs have also increased, for both our internal staff and contractors. Skilled electrical workers are in high demand across New Zealand, and we must offer competitive wages to attract and retain the expertise needed to operate your network safely.

We actively manage these cost pressures through a combination of efficiency measures and procurement practices. This includes bulk purchasing and standardising equipment specifications to reduce material costs, as well as collaborating with other EDBs to leverage collective buying power. We are improving productivity through better work planning and the use of mobile technology, which enables faster decision-making and more efficient field operations. In addition, we maintain strategic partnerships with contractors that balance cost efficiency with the capability needed to deliver high-quality outcomes for our customers.

However, we cannot eliminate external cost inflation entirely. We have used consumers price index (CPI) forecast information from the Westpac Economic Forecast Summary Spreadsheet to convert our constant expenditure forecasts to nominal expenditure forecasts and extrapolated at constant CPI for the final periods of the AMP where CPI forecast information is not available.

Kaikōura

5.4
The expenditure profile: balancing investment over time

Figure 5.2 shows how our total annual expenditure varies over the 10-year planning period.

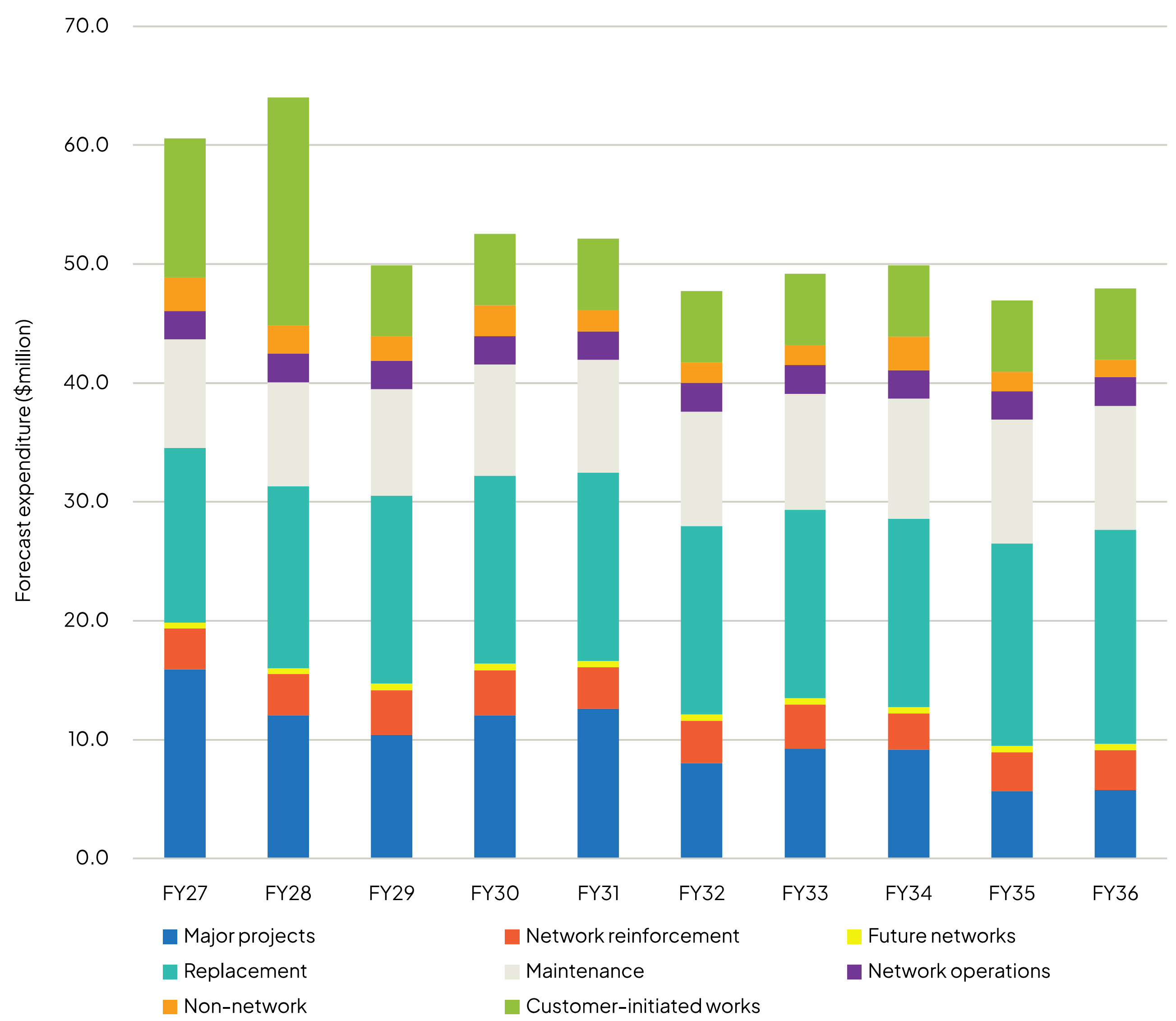


Figure 5.2 Total annual investment FY27–FY36

The profile shows higher investment in the next five years and moderate investment in years 6–10.

Years 1–5 (FY27–FY31): Higher investment

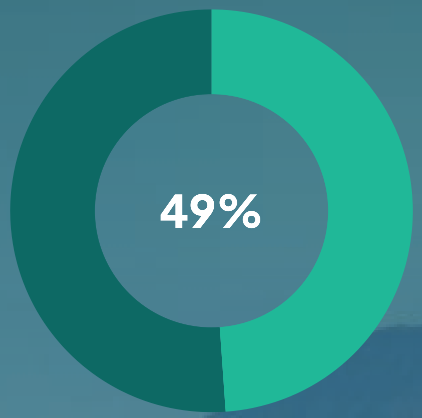
Total expenditure averages $55.8 million per year. This period includes major project delivery (Coldstream, Amberley, Hanmer Springs, Kaikōura) and addresses capacity constraints that are already affecting service in growing areas.

Years 6–10 (FY32–FY36): Moderated investment

Total expenditure averages $48.3 million per year. As major projects complete, capital expenditure reduces. However, replacement and maintenance programmes continue increasing to address the ongoing ageing of assets.

This profile balances addressing immediate capacity constraints while avoiding expenditure spikes. By spreading major projects across the decade and managing the replacement programme systematically, we deliver necessary improvements while keeping annual expenditure relatively steady.

5.5 Replacement and maintenance budget breakdown



Because replacement and maintenance together represent 49% of our total investment ($256 million over 10 years), we provide additional detail on how this expenditure is allocated across different asset types.

Kaikōura

5.5.1 Replacement expenditure by asset category

Table 5.2 sets out our replacement expenditure forecast for the 10-year period, FY27–FY36.

Table 5.2 Network replacement expenditure (FY27–FY36)

	Expenditure ($000)									
Category	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**	**FY36**
Overhead network	8,830	9,195	9,728	10,000	10,000	10,000	10,000	10,000	11,000	11,800
Pole-mounted transformers	960	960	960	960	960	960	960	960	960	960
Pole-mounted switchgear	550	575	594	579	553	558	550	555	569	596
Substations and switchgear	1,078	1,033	1,041	1,062	1,027	1,049	1,052	1,049	1,042	1,071
Zone substations	113	170	165	165	150	110	350	50	50	30
Secondary systems	784	775	758	797	797	796	756	763	799	776
Underground network	1,249	1,467	1,511	1,194	1,271	1,285	1,089	1,381	1,510	1,692
Network property	130	145	50	50	50	50	50	50	55	60
Corrective replacements	380	380	380	380	380	380	380	380	380	380
Fault replacements	635	635	635	635	635	635	635	635	635	635
Total	**14,709**	**15,335**	**15,822**	**15,822**	**15,823**	**15,823**	**15,822**	**15,823**	**17,000**	**18,000**

What this shows

Overhead network replacement (poles, lines, crossarms) represents 63% of the replacement programme ($100.5 million), reflecting the fact that overhead infrastructure makes up most of our network and some of it has been in place since the 1950s.

The increasing expenditure over time (from $8.8 million to $11.8 million annually) reflects the growing proportion of poles and lines reaching replacement age or condition. By spreading this work over the decade, we avoid cost spikes while systematically renewing the network.

Underground cable replacement increases from $1.2 million to $1.6 million annually as cables reach replacement criteria. Underground cable is more expensive to replace than overhead lines (often 5–10 times the cost per kilometre), so even relatively small lengths of cable replacement drive significant expenditure.

Transformer, switchgear, and secondary systems replacements remain relatively steady, reflecting our proactive condition-based approach. By replacing equipment based on condition assessment rather than waiting for failures, we can plan work efficiently and avoid emergency replacement costs.

5.5.2 Maintenance expenditure by asset category

Our 10-year forecast expenditure on network maintenance is set out in Table 5.3.

Table 5.3 Network maintenance expenditure (FY27–FY36)

	Expenditure ($000)									
Category	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**	**FY36**
Overhead network	3,202	2,805	2,905	3,005	3,105	3,205	3,305	3,405	3,505	3,605
Pole-mounted transformers	529	537	514	520	458	539	527	514	520	468
Pole-mounted switchgear	396	402	408	414	420	427	433	439	446	453
Substations and switchgear	859	872	885	898	911	925	939	953	967	982
Zone substations	758	637	698	853	849	717	651	767	857	779
Secondary systems	37	38	38	39	39	40	41	41	42	42
Underground network	527	531	502	509	508	502	506	502	509	508
Network property	121	121	121	121	121	121	121	121	121	121
Vegetation management	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590	2,690	2,700
Replacement & recovery	135	135	135	135	135	135	135	135	135	135
Corrective maintenance	635	635	635	635	635	635	635	635	635	635
Total	**9,109**	**8,733**	**8,961**	**9,349**	**9,501**	**9,656**	**9,793**	**10,102**	**10,427**	**10,428**

What this shows

Overhead network maintenance (inspections, minor repairs, defect rectification) represents the largest ongoing maintenance requirement. The increasing expenditure over time reflects both the growing network (more assets to maintain) and the ageing asset base (older equipment requires more frequent attention).

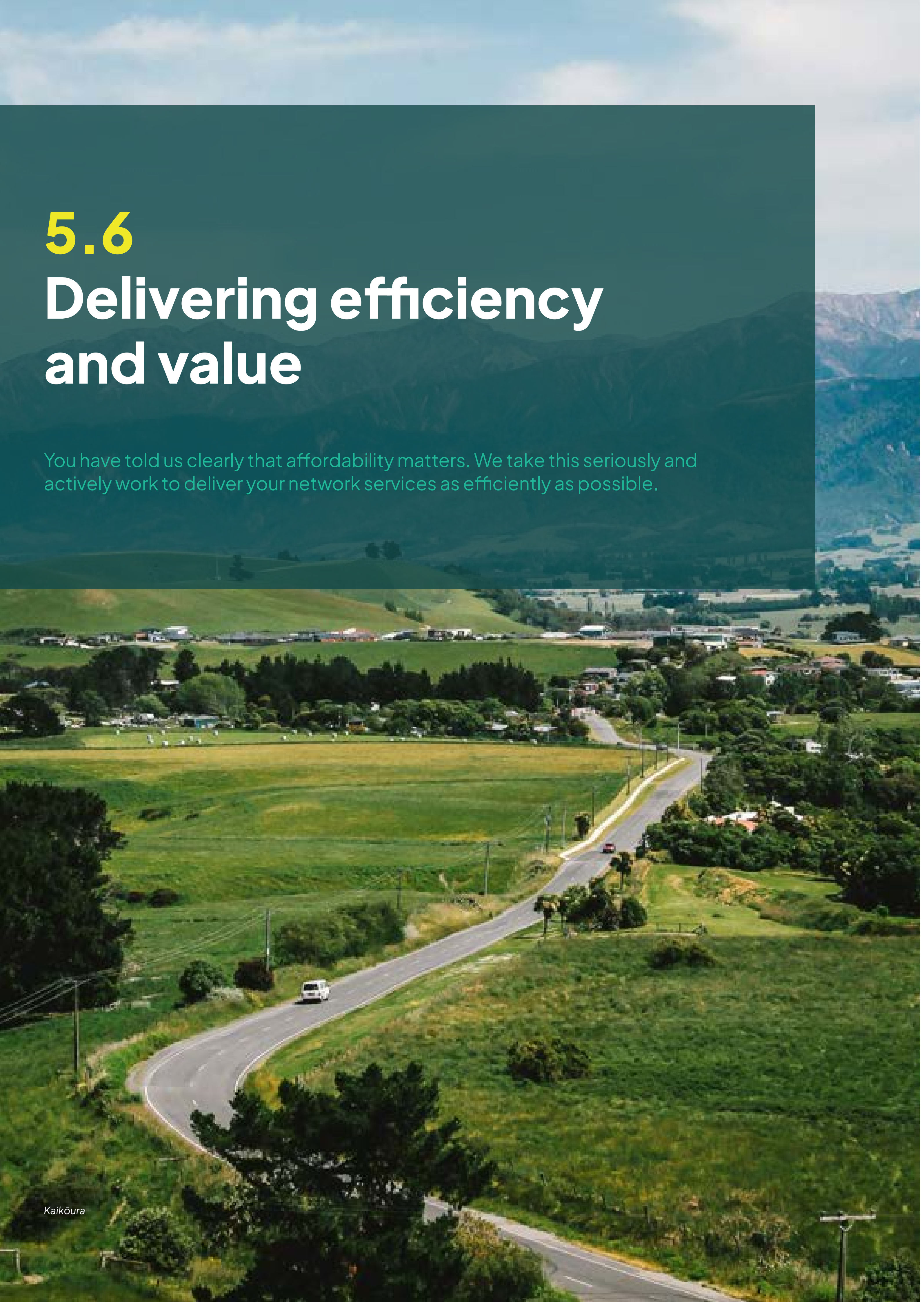
Zone substation maintenance shows more variability year-to-year, reflecting the scheduled major service intervals for power transformers and other critical equipment.

“Replacement and recovery” covers the costs of recovering and disposing of replaced equipment, transporting materials, and site reinstatement. This increases in line with the replacement programme.

Vegetation management (~$2 million annually) remains relatively steady, reflecting our systematic programme using AI-powered risk assessment to target trimming where it delivers the greatest reliability benefit.

5.6
Delivering efficiency and value

You have told us clearly that affordability matters. We take this seriously and actively work to deliver your network services as efficiently as possible.



Kaikōura

5.6.1
Our efficiency approach

Standardisation	We have standardised equipment specifications and designs wherever possible. This allows us to: • negotiate better prices through bulk purchasing • reduce design time for routine projects • train crews on consistent equipment • hold common spare parts, reducing emergency replacement costs.
Work planning	We plan our work carefully to avoid rushing. By scheduling replacements before equipment fails, we can: • combine multiple jobs in one area (reducing travel time) • schedule work during favourable weather • coordinate planned outages to minimise customer disruption • avoid premium rates for emergency callouts.
Technology investment	We are investing in tools and systems that make our people more productive, including: • mobile technology that allows field crews to access asset information and update records from the field • improved asset management systems that provide better data for decision-making • better work-planning systems that optimise crew deployment and reduce wasted travel. These investments require upfront expenditure but deliver ongoing efficiency benefits: doing more work with the same resources.
Collaborative procurement	As part of the Electricity Engineers' Association, we collaborate with other distribution businesses across New Zealand. This includes: • shared technical specifications (allowing multiple companies to tender on the same standards, increasing competition) • resource sharing during major emergencies • best practice exchange • benchmarking to identify improvement opportunities.

5.6.2 Benchmarking and performance targets

We actively benchmark our costs against other EDBs across New Zealand. Our target is to maintain both operating expenditure (OPEX) and capital expenditure (CAPEX) per ICP below the 75th percentile.

This means we aim to be more efficient than half of our peer group, but we are not chasing the absolute lowest cost, because that might compromise reliability or safety. The 75th percentile target represents good value: efficient delivery without gold-plating, and without cutting corners. Figure 5.3 below illustrates our $/ICP and network reliability performance against peer EDBs of similar size and characteristic.

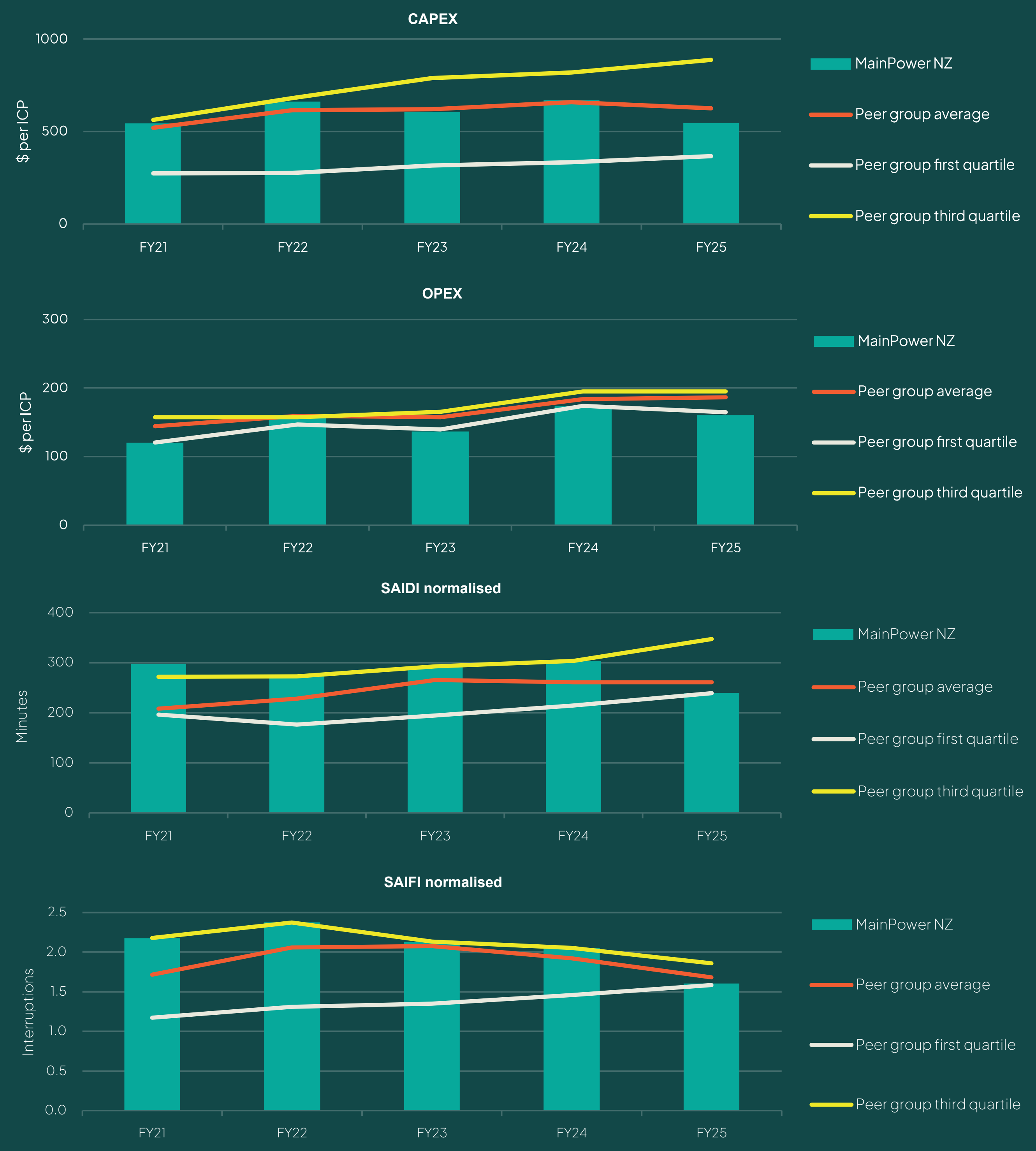


Figure 5.3 Benchmarking comparison (FY21–FY25)

5.6.3 Our asset management strategy focus over the next decade

Productivity improvements

We are implementing better work management systems and mobile technology to increase the amount of work completed per person-hour. Target: 10% productivity improvement by FY31.

Procurement savings

Through collaborative procurement and standardisation, we target 5% reduction in unit costs for major equipment categories (transformers, poles, cables) compared to FY26 baseline prices, adjusted for inflation.

Asset life extension

By using condition-based replacement rather than age-based replacement, we extend asset lives by an average of 5–10 years. This defers expenditure while maintaining reliability.

Maintenance optimisation

Using data analytics and condition monitoring, we optimise maintenance frequencies. Over-maintaining assets wastes money; under-maintaining them leads to failures. Getting this balance right delivers efficiency without compromising reliability.

These efficiency measures help offset external cost inflation and allow us to deliver the investment programme while managing bill impacts carefully.

5.7 Developing as an organisation

We have put a strong emphasis on efficiency to deliver our 10-year plan. By developing forward-looking plans, proactively managing resources, and standardising technical designs in partnership with other EDBs, we are prioritising streamlined operations and cost-effectiveness. Our focus on efficiency ensures that we not only meet the needs of our community now but also build a resilient and high-performing network for the future.

5.7.1 Planning our workload

We have carefully shaped our plan to ensure work is spread out evenly, so we can manage our resources responsibly and avoid sudden spikes in workload. By distributing work across the year, we enable a steady and predictable workflow for our team, which supports effective workforce planning.
This allows us to maintain a consistent staffing level, ensuring we have the right skills and people available when needed. Our approach not only helps to maintain safety, quality, and sustainability for our community, it also enhances job security and professional development opportunities for our employees.

5.7.2 Standardisation across our electricity network

To ensure our future work is as efficient and effective as possible, we are joining forces with other EDBs to use a shared set of technical designs for our network. By adopting these standard designs, we can deliver reliable, safe, and affordable services to our community, now and into the future.

Adopting standardised technical designs across our network offers a range of strategic, operational, and financial benefits that can significantly enhance network performance and resilience.

From a strategic perspective, standardisation supports long-term planning and scalability. It enables consistent design principles to be applied across new developments, upgrades, and maintenance activities, reducing complexity and improving interoperability. This consistency also facilitates clearer communication between engineering teams, contractors, and suppliers, which is particularly valuable in multi-party projects or when onboarding new staff.

Operationally, standardised designs streamline asset management and maintenance. Field crews benefit from familiar layouts and components, which reduces training time and improves fault response efficiency.
Spare parts inventories can be optimised, and diagnostic tools can be applied more uniformly, leading to faster resolution of outages and improved safety outcomes. Standardisation also supports digitalisation efforts, such as remote monitoring and predictive maintenance, by ensuring data consistency across assets.

Financially, the use of standardised designs can reduce procurement costs through bulk purchasing and long-term supplier agreements. It also lowers design and engineering overheads by reducing the need for bespoke solutions. Over time, these efficiencies contribute to lower total cost of ownership and improved return on investment for network assets.

By working with other EDBs to adopt a common set of standard designs, we share knowledge and learn from each other's experience, which helps us find better ways of doing things and avoid repeating work that has already been done. If there's ever an emergency or a need to expand our services quickly, having the same designs in place means we can respond faster and more effectively.

By working collaboratively with other EDBs we increase our operational efficiency, delivering a better outcome for all of our customers and stakeholders.

5.7.3 Collaborating across the industry

By working closely with our industry partners and other EDBs, we leverage our combined resources, expertise, and infrastructure to enhance the efficiency, reliability, and resilience of our networks. This includes standardisation of assets and design standards, which ensures efficient partnerships during business as usual and in times of emergency response. We also collaborate in event response, network knowledge, aligning ADMS, aligning procurement practices and processes, sharing quantity surveying data and systems, sharing stock availability, and aligning our billing standards.

5.7.4 Our commitment to local procurement

We are committed to sourcing equipment and materials locally wherever possible to support our regional economy and foster strong relationships with New Zealand suppliers. By prioritising local procurement, we can reduce transport costs and lead times, improve supply chain resilience, and contribute to the development of local industry capabilities. This approach also enables us to respond more quickly to urgent needs, as local suppliers can deliver equipment and services with greater flexibility. Through ongoing engagement with our local partners, we ensure that our procurement practices align with our values of sustainability, reliability, and community support, ultimately benefiting both our operations and the wider community.

5.7.5 Transitioning to a skills-based organisation

We're preparing for the future by developing a clear framework that helps us understand the skills our organisation needs to deliver our long-term AMP. This skills taxonomy, built on the World Economic Forum (WEF) Global Skills Taxonomy, guides our approach to workforce planning, making sure our teams are agile, efficient, and inclusive as our industry evolves.

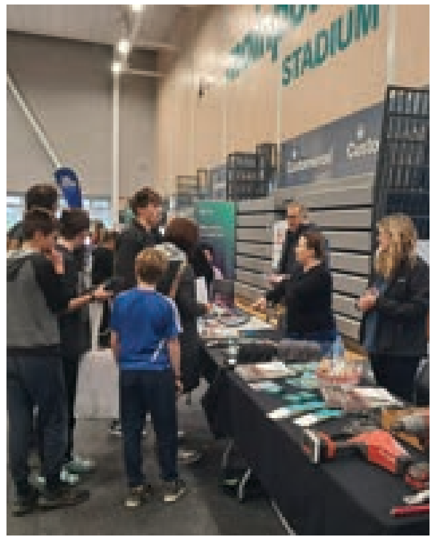
The WEF Skills Framework is an internationally recognised system that organises skills into easy-to-understand groups and highlights the abilities most valuable in today's workplaces. By using this framework, we can identify which skills matter most for our goals and ensure our people are equipped for what's ahead.

Looking towards 2026 and beyond, certain skills are becoming increasingly important. In particular, technological skills, such as understanding AI and working with big data, are expected to grow rapidly. Skills like analytical thinking, creativity, resilience, flexibility, and being comfortable with new technologies are not just desirable, but essential for our continued success.

Our taxonomy lays out these skills in organised groups, making it easier to see the core capabilities needed and where we can focus development. To put this into practice, we're piloting the framework with our Network team and drawing on expertise from our Future of Work group. We're using a simple internal platform, which uses generative technology to help map out the skills of our employees – creating visual mind maps that make it easy to see strengths and development areas.

5.7.6 Fostering the next generation

We are committed to developing and supporting the next generation within our organisation and industry. We focus on fostering essential skills, providing practical training opportunities, engaging with our community, and promoting diversity and inclusion. These themes ensure we build a strong, capable, and future-ready workforce that reflects our values and supports ongoing excellence.



Youth Expo

Apprentice training

Our apprentice programme is designed to give trainees hands-on experience by working alongside our team of fully qualified and experienced electrical professionals. Throughout their training, apprentices receive dedicated support and guidance, helping them develop the skills needed to become fully qualified and achieve their Electrical Workers Registration Board registration. The programme follows a well-structured pathway, with clear incentives and recognition at each key milestone, ensuring our apprentices are motivated and set up for long-term success. This approach not only prepares our future workforce but also ensures we continue to deliver safe, reliable, and high-quality service to our customers.

Graduate training

We welcome graduates into key areas such as asset management, engineering, network planning, technology, data analysis, and business administration. By giving graduates practical experience in these fields, we help them develop a broad range of skills and a clear understanding of how our teams work together to deliver reliable, cost-effective service for our community.

This approach means graduates are not limited to one area, they gain a well-rounded view of our operations. It also helps us stay flexible, as our people can adapt quickly to changing needs. By matching graduate placements with our current priorities, we meet today's challenges while also preparing for tomorrow. This supports our commitment to managing assets responsibly and responding quickly to the needs of those we serve.

We believe in creating an environment where learning never stops and new ideas are encouraged. Through the Graduate Programme, we attract talented individuals who are keen to make a difference. This not only strengthens our team but also helps us set high standards for the industry and ensures we continue to deliver reliable service at the least cost to our customers and community.

Community scholarships

We are proud to support the development of future engineering talent through our scholarship scheme, which is managed in partnership with the Aruhiko Power Engineering Excellence Trust. This scholarship is awarded for a one-year tenure and is specifically available to University of Canterbury engineering students who are in their second or third professional year of the Bachelor of Engineering (Honours) programme. In addition to financial support, successful recipients may also have the valuable opportunity to gain paid work experience with MainPower, providing them with practical industry exposure and a pathway to further growth within our organisation.
This initiative not only helps students advance their studies but also strengthens our talent pipeline and supports our commitment to nurturing the next generation of skilled professionals in our industry.

UC 2025 Aruhiko PEET Scholar Award

Early career development

We are committed to encouraging more young people and individuals from under-represented backgrounds to join our industry, helping to build a strong and diverse workforce for the future. By taking part in community events and programmes, we aim to open doors to rewarding careers and highlight the many opportunities our field has to offer.

GirlBoss

This year, we proudly supported the GirlBoss Edge Sustainability programme for the first time. This initiative is designed to inspire young women to explore careers in science, technology, engineering, and maths (STEM). Our staff also had the chance to act as mentors, sharing their experiences and supporting the next generation of leaders.

TechStep

We also worked alongside TechStep to create short videos that showcase technology roles in our industry. These videos were made to reach groups who are often under-represented, including Māori, Pasifika, and women. Two of our team members, Whitney Tahau and Blake Harkness, featured in these videos, helping to share their stories and encourage others to consider a future in technology.

STEM Careers Fair

At the University of Canterbury STEM Careers Fair, we connected directly with students from a range of backgrounds and study levels. We talked about jobs and internships available in our field, with a special focus on exciting areas like drones, AI, and process automation. Our team provided practical advice, answered questions, and helped students think differently about what their future careers might look like.

North Canterbury Youth Futures

Locally, we took part in the North Canterbury Youth Futures event, which brings together employers, education providers, and young people. This event gave us the chance to talk about the wide range of roles available in our organisation and explain the different career paths that are possible. It also allowed us to build stronger connections with other local employers and educators, working together to support young people as they start out in their careers.

Through these efforts, we continue to invest in the future of our industry and our community, making sure everyone has the chance to learn, grow, and succeed.

5.8 Technology enhancing our business

5.8.1 Advanced distribution management system (ADMS) upgrade

We are working together with Marlborough Lines to ensure our technology systems for managing assets and electricity distribution are fully aligned. This means using the same GIS and ADMS so our teams can easily share information and support each other, especially in emergencies. Over time, we are merging our technology, processes, and ways of working in several stages. This gradual approach helps us provide more reliable service, improve disaster response, and reduce costs for our customers. By standardising our practices and working together on purchasing equipment and services, we avoid duplicating effort and make the most of our resources. Our goal is to deliver dependable service, keep costs down, and ensure our systems work seamlessly together for the benefit of everyone in our communities.

5.8.2 Improving our vegetation strategy

We are currently evaluating the Intelligent Vegetation Management System (IVMS) as a potential tool to support vegetation management across our network. IVMS uses satellite imagery and AI to assess vegetation risks and generate targeted work plans. A key feature is its ability to predict the growth rates of different tree species at a span level, between individual power poles, using high-resolution multispectral imagery and deep learning models. These predictions are then clustered at section and feeder levels to inform a prioritised trim plan. The system can identify which trees pose the greatest risk based on species-specific growth patterns, proximity to infrastructure, and historical hazard data, allowing for more precise and timely intervention planning.

Figure 5.4 An outage map for Hanmer Springs using data from ESRI

5.8.3 Enhancing our geospatial applications

We are enhancing our ability to manage the network by introducing new geospatial tools. Our team is rolling out a suite of ESRI mapping applications that will make it easier for us to collect and process information about our assets and the environment. These tools also allow us to work more closely with partners such as local councils, making it simpler to share data and collaborate on projects that benefit the whole community.

Alongside this, we are adopting the Feature Manipulation Engine (FME) application, which helps us turn raw information into clear, useful maps and reports. By combining these technologies, we can bring together details about our network and the natural environment in one place. This means we can make better decisions, respond more quickly to issues, and ensure our service remains reliable – all while keeping costs down for our customers. Our investment in these tools supports our commitment to delivering value and dependable service to everyone we serve.

5.8.4 Implementing digital data capture

We're making it easier and more reliable to manage our network by collecting information digitally. This means we can gather up-to-date details about our assets, including photos of our work, while our team is out in the field. By capturing data on the spot, we avoid the need for paper forms and make sure important information is entered only once, reducing errors and saving time. The use of GPS technology helps us record the exact location of every asset, so our records are accurate and easy to update. We also use aerial surveys with advanced imaging to improve and correct older data, ensuring the information we rely on is as precise as possible.

Having accurate records is essential for keeping our network safe and reliable. Our digital tools let us review and update information quickly, which means we can spot and remove duplicate entries and avoid mistakes when sharing data between teams. Because we're able to process new information faster, often within days, we can respond to issues promptly and keep our service dependable. All of these improvements help us deliver reliable service to our community while keeping costs down.

5.8.5 Online portal for customers to engage with us on their projects

5.8.6 Utilising smart meters to understand our low-voltage network

We've recently gained access to smart meter information and a powerful data analysis platform through our partnership with Hiko (SmartCo). This marks an important step forward in helping us understand how electricity is used across our network, spot trends in energy use, and keep a close eye on the quality of supply our customers receive. With this new data, we can make more informed decisions about how we plan and invest in our network, ensuring we continue to deliver reliable service at the best possible cost.

Using smart meter data and more advanced methods to model our network also sets us up for the future, giving us a strong foundation to manage new markets and technologies as they emerge. These improvements mean we're better equipped to serve our community, now and in the years ahead.

5.9

Improving energy efficiency

By reducing energy losses across our network, we can ensure that more energy reaches our customers efficiently. Whenever we update parts of our network, such as converting from 11 kV to 22 kV, we install new transformers that meet the latest Minimum Energy Performance Standards. Choosing equipment for our network is a careful process, and we always prioritise options that use energy more efficiently and help keep our records accurate and up to date.

Alongside these technical improvements, we are committed to supporting our community through education programmes and sponsorships that share practical advice about insulation and energy efficiency solutions. We regularly engage with our customers to explore new ways of managing energy demand, from considering emerging technologies to understanding how people use electricity in their homes and businesses. By working together, making smart investments, and focusing on quality, we can help everyone benefit from a lower-cost energy supply.

Waipara


Kaikōura

6
What this means for you

Hanmer Springs

This section translates the investment programme into costs for you. We show you what you pay for when your electricity bill arrives, how our charges fit into your overall power costs, and what value you receive for your investment.

What you will find in this section

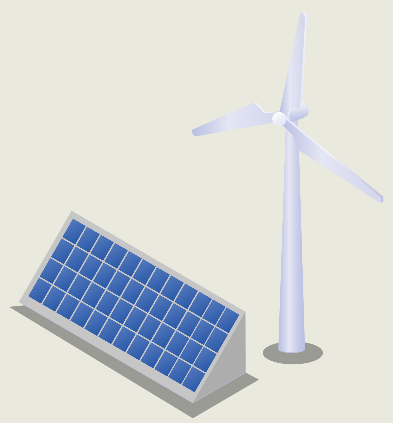
- Who you pay through your electricity bill and where it goes
- What we do with that money
- How our network charges are structured

6.1
Understanding your electricity bill

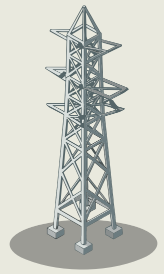
When you open your power bill each month, you are paying for multiple services provided by different companies. Let us break this down so you can see exactly where your money goes.

6.1.1
Who you are paying

Your bill comes from your electricity retailer: companies like Contact Energy, Mercury, Genesis, or others. But that retailer is collecting money on behalf of several different entities.

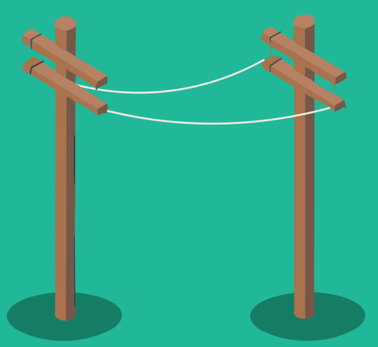


Generators produce the electricity at power stations (mostly hydro, geothermal, and wind in New Zealand).

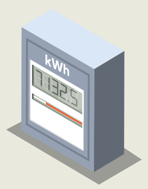


Transpower operates the national grid carrying power from generators to substations across the country.

Retailers buy electricity from generators, manage your account, send bills, and provide customer service.



Distributors (that is us, MainPower) operate the local networks delivering power from the national grid to your property.



Metering companies install and maintain the meter at your property.

Government and regulatory bodies collect levies to fund industry regulation and market operations.

The Government collects GST on the total bill.

Each plays a necessary role in getting electricity to your property. Your retailer bundles all these charges into one bill for simplicity.

6.1.2
The typical North Canterbury bill breakdown

For a typical household in North Canterbury using about 8,000 kWh per year, the average monthly electricity bill is approximately $280 (including GST). Figure 6.1 shows how that breaks down.

Note: All prices are approximate

Figure 6.1 Breakdown of the average household power bill from the Electricity Authority website, www.ea.govt.nz

The important takeaway: MainPower's charges make up about 24.5% of your total bill. The other 75.5% goes to generators, Transpower, retailers, metering companies, levies, and tax.

This means when your total power bill increases, it is not necessarily because of changes in our network charges. Generation costs fluctuate with fuel prices and hydro lake levels. Transmission charges change as Transpower upgrades the national grid. Retailers adjust their margins. The Government sets the GST rate.

- **What we control:** MainPower's network charges (the 24.5%)
- **What we do not control:** Generation, transmission, retail, metering, levies, and GST (the 75.5%)

When you have concerns about power costs, we want you to understand which portion relates to our services and which relates to other parts of the supply chain.

6.2
What you pay MainPower for

That 24.5% of your bill covering MainPower's services pays for maintaining and improving the physical network delivering electricity to your property: the poles, lines, transformers, substations, and all the equipment described in section 3.

6.2.1 Breaking down your network charge

Your MainPower network charges include four main components, as shown in Figure 6 2

Figure 6.2 Breakdown of network charge

We have prepared this plan with care, focusing only on the essential investments needed to keep your power reliable while delivering the best possible value. The information in this section shows how our proposed AMP would shape your monthly bill.

Recovering network investment

$40 per month
58% of network charge

This recovers the cost of assets we have already built plus new assets we are building now. Every piece of equipment on the network has been paid for through electricity charges, and customers benefit from that equipment over its entire lifetime (typically 30-60 years).

This includes:

- **Depreciation:** As assets age, we set aside money to eventually replace them
- **Return on investment:** The capital invested in the network earns a regulated return (currently about 5.4% annually)
- **Interest costs:** Where we have borrowed to fund investment, we pay interest on that debt

The Commerce Commission regulates what return we can earn on network investment.

Operating and maintaining the network

$18 per month
26% of network charge

This covers the day-to-day running of the network, including:

- inspecting and maintaining equipment (detailed in section 3)
- managing vegetation near lines
- responding to faults and outages
- operating the network control room
- managing connections and customer requests
- planning future network needs.

These are ongoing costs that occur every year to keep the network functioning safely and reliably.

Taxes and levies

$6 per month
9% of network charge

We pay several taxes and levies that are passed through to customers, including:

- local authority rates on network property
- ACC levies for workplace safety insurance
- a Commerce Commission levy for industry regulation
- an Electricity Authority levy for market operations.

Supporting the future

$5 per month
7% of network charge

This includes:

- innovation programmes testing new technologies
- systems and capability development
- network planning and analysis
- continual improvement initiatives.

6.2.2 How network charges are structured

Your MainPower network charges include several components.

Most customers pay MainPower through two components on their retailer's bill:

Daily charge:

A fixed amount per day, regardless of how much power you use. This reflects the fact that maintaining the network has fixed costs: we need to maintain the poles and lines to your property whether you use a lot of power or a little.

Usage charges:

A per-kilowatt-hour (kWh) charge based on how much power you use. This reflects the variable costs of operating the network and the impact of your consumption on network capacity.

For most residential customers, the daily charge is approximately $1.90 per day ($58 per month), and the usage charge is approximately $0.025 per kWh. At 8,000 kWh annual usage, this totals about $69 per month.

Different customer groups have different tariff structures reflecting their usage patterns and the costs they impose on the network. Your retailer can explain which tariff options are available to you.

Hanmer Springs

Kaikōura

Appendices

Appendix 1 –
Information disclosure requirements: compliance summary

This appendix maps the mandatory disclosure requirements set out in the Electricity Distribution Information Disclosure Determination to the relevant sections in this AMP.

Table A.1 Electricity Distribution Information Disclosure Amendment Determination 2024, Attachment A requirements

Clause	Requirement area	Mandatory content	AMP location
3.1–3.3	Summary and purpose	Summary overview, purpose statement, objectives, corporate mission/vision	Strategic overview
3.4	Planning period	Minimum 10 projected years coverage	Section 5.2: Our 10-year investment programme
3.5	Director approval date	Date AMP approved by directors	
3.6	Stakeholder interests	Stakeholder interests, identification, accommodation, conflict management	Section 1: Your network, your priorities
3.7	Accountabilities	Governance, executive, field operations accountabilities	Section 2.1.1: Who we are
3.8–3.10	Assumptions & strategy	Significant assumptions, quantified, uncertainty sources, price inflators	Section 1: Your network, your priorities Section 5: Creating a sustainable network
3.11–3.12	Systems & data management	Systems overview, data requirements, quality controls, asset health models, limitations	Section 3.14: Information systems and data management
3.13–3.15	Asset management	Maintenance processes, asset management documentation, asset management strategies, objectives, policies and plans	Section 3: Managing our assets
3.16	Financial presentation	All financial values in constant price NZ dollars	Section 5.3.6: Input cost pressures
4.1	Service areas description	Service areas, consumers, load characteristics, peak demand by sub-network	Section 2.5: Your electricity network
4.2	Network configuration	GXPs, generation > 1 MW, subtransmission, security classes, low-voltage system, SCADA	Section 2.5: Your electricity network
4.2.7	Non-network solutions	Quantification of non-network solution contributions, party identification	Section 2.11: Non-network solutions and distributed energy resources
4.4	Asset registers/profiles	Assets by category, voltage, quantity, age profiles, condition, systemic issues	Section 3: Managing our assets
Note	Network maps	Network maps and single line diagram of subtransmission	Section 2.9: Network configuration Section 4: Building the network of the future
5 & 6	Performance targets	Annual performance targets for all AMP years, SAIDI and SAIFI for 5 years	Section 1.4: Our service commitment to you
8 & 9	Target justification	Basis for targets, consumer expectations, legislation, historical comparison	Section 1.4: Our service commitment to you
11.1	Planning criteria	Network planning criteria, security and reliability standards	Section 4: Building the network of the future Section 2: Delivering for our communities: people, capability, and resilience
11.8	Demand forecasts & constraints	Demand forecasts to zone substation level for 5+ years, growth constraints	Section 2.5: Your electricity network Section 2.9: Network configuration
11.9.2	Option analysis (non-network)	Cost-effectiveness analysis of non-network vs traditional solutions	Section 2: Delivering for our communities: people, capability, and resilience
11.12.3	Constraint information sharing	Methodology for sharing constraints with third parties, including low voltage	Section 1.6: How we serve you: connections and customer service Section 2: Delivering for our communities: people, capability, and resilience
12.1	Maintenance strategy	Key drivers and assumptions for maintenance planning	Section 3: Managing our assets
12.5	Lifecycle CAPEX methodology	Approach and rationale for lifecycle asset management CAPEX	Section 3: Managing our assets
12.6	Vegetation management	Approach and assumptions for vegetation management expenditure	Section 3.7: Vegetation management
12.7	Non-network in lifecycle	Consideration of non-network solutions in lifecycle CAPEX/OPEX	Section 3: Managing our assets
14	Risk management	Risk policies, assessment, mitigation, high-impact events, emergency response	Section 2: Delivering for our communities: people, capability, and resilience
15	Performance evaluation	Review of progress against previous AMP, target performance	Section 1.3: Understanding our network performance
16	Capability assessment	Realistic AMP processes, organisational capabilities for implementation	Section 5.7: Developing as an organisation
17.1	Interruption communication	Communication process for planned and unplanned interruptions	Section 1.6.1: Notice of planned and unplanned interruptions
17.2.1	Voltage quality monitoring	Low-voltage quality monitoring, non-compliance response, communication	Section 2.5.7: Voltage quality and low-voltage network monitoring
17.2.2	Low-voltage constraint data collection	Load/injection constraint monitoring, low-voltage data challenges, analysis/modelling	https://www.mainpower.co.nz/wp-content/uploads/2026/03/2026---Clause-2.6.1b-information.pdf
17.3	Customer service standards	Engagement protocols, service measures, satisfaction, complaints	Section 1: Your network, your priorities
17.4	Connection constraint information	Proactive sharing of constraints with new consumers, including low voltage	Section 1.6: How we serve you: connections and customer service Section 1.3.4 Voltage quality and low-voltage network monitoring
17.5	New capacity impact assessment	Assessment of significant new demand/generation/storage impacts	Section 1.6: How we serve you: connections and customer service Section 2: Delivering for our communities: people, capability, and resilience
17.6	Innovation initiatives	Innovation practices, case studies, outcomes, metrics, third-party reliance	Section 5.6: Delivering efficiency and value Section 5.7: Developing as an organisation Section 5.8: Technology enhancing our business Section 5.9: Improving energy efficiency

Appendix 2 – Abbreviations

ADMS	advanced distribution management system
AI	artificial intelligence
ALARP	as low as reasonably practicable
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
CAPEX	capital expenditure
CDEM	civil defence emergency management
CPI	consumers price index
CRM	customer relationship management
DPP	default price-quality path
EDB	electricity distribution businesses
ERP	enterprise resource planning
EV	electric vehicle
FME	Feature Manipulation Engine
FTE	full-time equivalent
GIS	geographic information system
GXP	grid exit point
ICP	installation control point
IVMS	Intelligent Vegetation Management System
NEMA	National Emergency Management Agency
NZTA	NZ Transport Agency Waka Kotahi
OPEX	operating expenditure
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SF_6	sulphur hexafluoride
SMS	short messaging service
STEM	science, technology, engineering, and maths
WEF	World Economic Forum

Appendix 3 – Directors' certificate

mainpower

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CERTIFICATE FOR YEAR-BEGINNING 1 APRIL 2026 DISCLOSURE

Pursuant to Clause 2.9.1 of Section 2.9 of the Electricity Distribution Disclosure Determination 2012.

We, ANTHONY CHARLES KING and STEPHEN PAUL LEWIS, being Directors of MainPower New Zealand Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of MainPower New Zealand 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 MainPower New Zealand Limited's corporate vision and strategy and are documented in retained records.

Anthony Charles King	Stephen Paul Lewis
27/02/2026	27/02/2026
Date	Date

Appendix 4 – Schedule 11a: Report on forecast capital expenditure

		FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
11a(i)	Expenditure on Assets Forecast	$000 (in nominal dollars)										
	Consumer connection	6,000	11,700	19,589	6,250	6,391	6,538	6,689	6,842	7,000	7,160	7,325
	System growth	16,330	17,819	13,513	13,287	13,644	13,727	9,735	11,161	11,129	6,767	7,020
	Asset replacement and renewal	13,085	14,708	15,646	16,481	16,853	17,242	17,638	18,044	18,459	20,288	21,975
	Asset relocations	–	–	–	–	–	–	–	–	–	–	–
	Reliability, safety, and environment:											
	Quality of supply	58	879	1,942	1,050	1,702	1,468	1,522	570	1,323	716	794
	Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
	Other reliability, safety, and environment	300	675	357	417	1,512	2,329	1,639	3,022	1,767	3,181	3,296
	Total reliability, safety, and environment	358	1,554	2,299	1,466	3,214	3,797	3,161	3,592	3,090	3,897	4,090
	Expenditure on network assets	35,772	45,782	51,047	37,485	40,102	41,304	37,223	39,639	39,677	38,112	40,410
	Expenditure on non-network assets	1,705	1,293	279	417	1,299	499	245	365	1,692	119	85
	Expenditure on assets	37,477	47,075	51,326	37,902	41,401	41,803	37,468	40,004	41,369	38,232	40,495
plus	Cost of financing	–	–	–	–	–	–	–	–	–	–	–
less	Value of capital contributions	3,500	3,500	3,571	3,646	3,728	3,814	3,902	3,991	4,083	4,177	4,273
plus	Value of vested assets	–	–	–	–	–	–	–	–	–	–	–
	Capital expenditure forecast	**33,977**	**43,575**	**47,755**	**34,256**	**37,673**	**37,989**	**33,566**	**36,013**	**37,286**	**34,055**	**36,222**
	Assets commissioned	25,632	37,464	46,712	44,747	42,956	48,674	35,151	27,756	34,543	46,515	44,024

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
	$000 (in constant prices)										
Consumer connection	6,000	11,700	19,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
System growth	16,330	17,819	13,244	12,756	12,810	12,597	8,733	9,788	9,540	5,670	5,750
Asset replacement and renewal	13,085	14,708	15,335	15,823	15,823	15,823	15,823	15,823	15,823	17,000	18,000
Asset relocations	–	–	–	–	–	–	–	–	–	–	–
Reliability, safety, and environment:											
Quality of supply	58	879	1,904	1,008	1,598	1,347	1,365	500	1,134	600	650
Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
Other reliability, safety, and environment	300	675	350	400	1,420	2,137	1,470	2,650	1,515	2,666	2,700
Total reliability, safety, and environment	**358**	**1,554**	**2,254**	**1,408**	**3,018**	**3,484**	**2,835**	**3,150**	**2,649**	**3,266**	**3,350**
Expenditure on network assets	**35,772**	**45,782**	**50,034**	**35,986**	**37,651**	**37,904**	**33,391**	**34,760**	**34,011**	**31,936**	**33,100**
Expenditure on non-network assets	1,705	1,293	273	400	1,220	458	220	320	1,450	100	70
Expenditure on assets	**37,477**	**47,075**	**50,307**	**36,386**	**38,871**	**38,362**	**33,611**	**35,080**	**35,461**	**32,036**	**33,170**

Subcomponents of expenditure on assets (where known)
Energy efficiency and demand side management, reduction of energy losses
Overhead to underground conversion
Research and development

Appendix 4 – Schedule 11a: Report on forecast capital expenditure (continued)

		FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
11a(i)	Expenditure on Assets Forecast (continued)	$000 (in nominal dollars)										
	Difference between nominal and constant price forecasts											
	Consumer connection	–	–	389	250	391	538	689	842	1,000	1,160	1,325
	System growth	–	(0)	268	531	834	1,130	1,002	1,374	1,589	1,097	1,270
	Asset replacement and renewal	–	–	311	659	1,030	1,419	1,816	2,221	2,636	3,288	3,975
	Asset relocations	–	–	–	–	–	–	–	–	–	–	–
	Reliability, safety, and environment:											
	Quality of supply	–	(0)	39	42	104	121	157	70	189	116	144
	Legislative and regulatory	–	–	–	–	–	–	–	–	–	–	–
	Other reliability, safety, and environment	–	–	7	17	92	192	169	372	252	516	596
	Total reliability, safety, and environment	**–**	**(0)**	**46**	**59**	**196**	**313**	**325**	**442**	**441**	**632**	**740**
	Expenditure on network assets	**–**	**(0)**	**1,014**	**1,498**	**2,451**	**3,400**	**3,832**	**4,880**	**5,666**	**6,177**	**7,310**
	Expenditure on non-network assets	–	–	6	17	79	41	25	45	242	19	15
	Expenditure on assets	**–**	**(0)**	**1,019**	**1,515**	**2,531**	**3,441**	**3,857**	**4,925**	**5,908**	**6,196**	**7,325**

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10-year planning period in Schedule 15.

Appendix 4 –
Schedule 11a: Report on forecast capital expenditure (continued)

11a(ii)	Consumer Connection	FY26	FY27	FY28	FY29	FY30	FY31
	*Consumer types defined by EDB**			$000 (in constant prices)			
	Residential	3,600	4,355	4,355	4,355	4,355	4,355
	Commercial	1,120	1,301	1,301	1,301	1,301	1,301
	Council pumping	800	143	143	143	143	143
	Irrigation	120	121	121	121	121	121
	Other	360	80	80	80	80	80
		–	5,700	13,200			
	Consumer connection expenditure	6,000	11,700	19,200	6,000	6,000	6,000
less	Capital contributions funding consumer connection	3,500	3,500	3,500	3,500	3,500	3,500
	Consumer connection less capital contributions	2,500	8,200	15,700	2,500	2,500	2,500

11a(iii)	System Growth	FY26	FY27	FY28	FY29	FY30	FY31
				$000 (in constant prices)			
	Subtransmission	5,122	–	155	1,164	2,514	6,335
	Zone substations	8,045	14,432	10,318	6,695	9,528	5,232
	Distribution and low-voltage lines	2,726	360	1,227	2,352	–	–
	Distribution and low-voltage cables	437	1,527	1,545	1,545	769	1,030
	Distribution substations and transformers	–	–	–	–	–	–
	Distribution switchgear	–	–	–	–	–	–
	Other network assets	–	1,500	–	1,000	–	–
	System growth expenditure	16,330	17,819	13,244	12,756	12,810	12,597
less	Capital contributions funding system growth	–	–	–	–	–	–
	System growth less capital contributions	16,330	17,819	13,244	12,756	12,810	12,597

11a(iv)	Asset Replacement and Renewal	FY26	FY27	FY28	FY29	FY30	FY31
				$000 (in constant prices)			
	Subtransmission	–	–	–	–	–	–
	Zone substations	140	113	170	165	165	150
	Distribution and LV lines	8,326	8,830	9,195	9,728	10,000	10,000
	Distribution and LV cables	793	1,249	1,467	1,511	1,194	1,271
	Distribution substations and transformers	1,626	2,038	1,993	2,001	2,022	1,987
	Distribution switchgear	517	550	575	594	579	553
	Other network assets	1,682	1,928	1,935	1,823	1,862	1,862
	Asset replacement and renewal expenditure	13,085	14,708	15,335	15,823	15,823	15,823
less	Capital contributions funding asset replacement and renewal	–	–	–	–	–	–
	Asset replacement and renewal less capital contributions	13,085	14,708	15,335	15,823	15,823	15,823

11a(v)	Asset Relocations	FY26	FY27	FY28	FY29	FY30	FY31
	*Project or programme**			$000 (in constant prices)			
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other project or programmes – asset relocations	–	–	–	–	–	–
	Asset relocations expenditure	–	–	–	–	–	–
less	Capital contributions funding asset relocations						
	Asset relocations less capital contributions	–	–	–	–	–	–

11a(vi)	Quality of Supply	FY26	FY27	FY28	FY29	FY30	FY31
	*Project or programme**			$000 (in constant prices)			
	Feeder reinforcement	58	379	1,704	127	–	240
	Voltage improvement	–	–	–	481	1,148	607
	Low voltage network	–	350	200	200	250	300
	Network automation	–	150	–	200	200	200
	All other project or programmes – quality of supply	–	–	–	–	–	–
	Quality of supply expenditure	58	879	1,904	1,008	1,598	1,347
less	Capital contributions funding quality of supply	–	–	–	–	–	–
	Quality of supply less capital contributions	58	879	1,904	1,008	1,598	1,347

Appendix 4 –
Schedule 11a: Report on forecast capital expenditure (continued)

11a(vii)	Legislative and Regulatory	FY26	FY27	FY28	FY29	FY30	FY31
	*Project or programme**			$000 (in constant prices)			
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes - legislative and regulatory	–	–	–	–	–	–
	Legislative and regulatory expenditure	–	–	–	–	–	–
less	Capital contributions funding legislative and regulatory	–					
	Legislative and regulatory less capital contributions	–	–	–	–	–	–

11a(viii)	Other Reliability, Safety, and Environment	FY26	FY27	FY28	FY29	FY30	FY31
	*Project or programme**			$000 (in constant prices)			
	Distribution lines	300	200	150	200	1,120	627
	Distribution cables	–	–	–	–	–	1,210
	Substations	–	475	200	200	300	300
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes - other reliability, safety, and environment	–	–	–	–	–	–
	Other reliability, safety, and environment expenditure	300	675	350	400	1,420	2,137
less	Capital contributions funding other reliability, safety, and environment	–	–	–	–	–	–
	Other reliability, safety, and environment less capital contributions	300	675	350	400	1,420	2,137

11a(xi)	Non-Network Assets	FY26	FY27	FY28	FY29	FY30	FY31
	*Project or programme**			$000 (in constant prices)			
	Routine expenditure						
	Asset management	435	1,293	273	400	1,220	458
	IT systems	1,270	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes – routine expenditure						
	Routine expenditure	1,705	1,293	273	400	1,220	458
	Atypical expenditure						
	*Project or programme**						
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	[Description of material project or programme]	–	–	–	–	–	–
	All other projects or programmes – atypical expenditure	–	–	–	–	–	–
	Atypical expenditure	–	–	–	–	–	–
	Expenditure on non-network assets	1,705	1,293	273	400	1,220	458

Appendix 4 –
Schedule 11b: Report on forecast operational expenditure

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
OPEX forecast	**$000 (in nominal dollars)**										
Service interruptions and emergencies	1,200	1,200	1,224	1,250	1,278	1,308	1,338	1,368	1,400	1,432	1,465
Vegetation management	1,800	1,910	2,061	2,208	2,365	2,528	2,687	2,851	3,021	3,210	3,296
Routine and corrective maintenance and inspection	6,692	7,065	6,711	6,985	7,449	7,680	7,927	8,163	8,607	9,073	9,269
Asset replacement and renewal	–	205	209	214	219	224	229	234	239	245	251
Network OPEX	**9,692**	**10,380**	**10,206**	**10,657**	**11,310**	**11,739**	**12,180**	**12,616**	**13,267**	**13,960**	**14,281**
System operations and network support	15,181	16,157	16,484	16,830	17,209	17,606	18,011	18,425	18,849	19,282	19,725
Business support	8,183	8,688	8,864	9,050	9,254	9,467	9,685	9,908	10,135	10,368	10,607
Non-network solutions provided by a related party or third party	–	–	–	–	–	–	–	–	–	–	–
Non-network OPEX	**23,364**	**24,845**	**25,348**	**25,880**	**26,463**	**27,074**	**27,696**	**28,333**	**28,984**	**29,650**	**30,332**
Operational expenditure	**33,056**	**35,225**	**35,554**	**36,537**	**37,773**	**38,813**	**39,876**	**40,949**	**42,251**	**43,610**	**44,613**

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
	$000 (in constant prices)										
Service interruptions and emergencies	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Vegetation management	1,800	1,910	2,020	2,120	2,220	2,320	2,410	2,500	2,590	2,690	2,700
Routine and corrective maintenance and inspection	6,692	7,065	6,578	6,706	6,994	7,047	7,111	7,158	7,378	7,602	7,593
Asset replacement and renewal	–	205	205	205	205	205	205	205	205	205	205
Network OPEX	**9,692**	**10,380**	**10,003**	**10,231**	**10,619**	**10,773**	**10,926**	**11,063**	**11,373**	**11,697**	**11,698**
System operations and network support	15,181	16,157	16,157	16,157	16,157	16,157	16,157	16,157	16,157	16,157	16,157
Business support	8,183	8,688	8,688	8,688	8,688	8,688	8,688	8,688	8,688	8,688	8,688
Non-network solutions provided by a related party or third party	–	–	–	–	–	–	–	–	–	–	–
Non-network OPEX	**23,364**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**	**24,845**
Operational expenditure	**33,056**	**35,225**	**34,848**	**35,076**	**35,464**	**35,618**	**35,771**	**35,908**	**36,218**	**36,542**	**36,543**

Subcomponents of operational expenditure (where known)											
Energy efficiency and demand side management, reduction of energy losses	–	–	–	–	–	–	–	–	–	–	–
Direct billing*	–	–	–	–	–	–	–	–	–	–	–
Research and development	–	–	–	–	–	–	–	–	–	–	–
Insurance	1,065	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026	1,026

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

Appendix 4 – Schedule 11b: Report on forecast operating expenditure (continued)

	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Difference between nominal and real forecasts						($000)					
Service interruptions and emergencies	–	–	24	50	78	108	138	168	200	232	265
Vegetation management	–	–	41	88	145	208	277	351	431	520	596
Routine and corrective maintenance and inspection	–	–	133	279	455	632	816	1,005	1,229	1,470	1,677
Asset replacement and renewal	–	–	4	9	13	18	24	29	34	40	45
Network OPEX	**–**	**–**	**203**	**426**	**691**	**966**	**1,254**	**1,553**	**1,895**	**2,262**	**2,583**
System operations and network support	–	–	327	673	1,052	1,449	1,854	2,268	2,692	3,125	3,568
Business support	–	–	176	362	566	779	997	1,220	1,447	1,680	1,919
Non-network solutions provided by a related party or third party	–	–	–	–	–	–	–	–	–	–	–
Non-network OPEX	**–**	**–**	**503**	**1,035**	**1,618**	**2,229**	**2,851**	**3,488**	**4,139**	**4,805**	**5,487**
Operational expenditure	**–**	**–**	**706**	**1,461**	**2,309**	**3,195**	**4,105**	**5,041**	**6,034**	**7,068**	**8,070**

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10-year planning period in Schedule 15.

Appendix 4 –
Schedule 12a: Report on asset condition

				Asset condition at start of planning period (percentage of units by grade)							
Voltage	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
All	Overhead line	Concrete poles / steel structure	No.	0.14%	0.09%	7.66%	34.52%	57.40%	0.20%	2	1.50%
All	Overhead line	Wood poles	No.	1.51%	1.79%	31.75%	55.50%	8.74%	0.72%	2	6.50%
All	Overhead line	Other pole types	No.	-	-	-	-	-	-	N/A	-
HV	Subtransmission line	Subtransmission OH up to 66 kV conductor	km	0.83%	26.65%	24.10%	15.59%	32.83%	-	2	-
HV	Subtransmission line	Subtransmission OH 110 kV+ conductor	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG up to 66 kV (XLPE)	km	-	0.23%	41.83%	4.66%	53.28%	-	3	0.20%
HV	Subtransmission cable	Subtransmission UG up to 66 kV (oil pressurised)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG up to 66 kV (gas pressurised)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG up to 66 kV (PILC)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG 110 kV+ (XLPE)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG 110 kV+ (oil pressurised)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG 110 kV+ (gas pressurised)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission UG 110 kV+ (PILC)	km	-	-	-	-	-	-	N/A	
HV	Subtransmission cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	
HV	Zone substation buildings	Zone substations up to 66 kV	No.	-	44.44%	16.67%	16.67%	22.22%	-	3	10.00%
HV	Zone substation buildings	Zone substations 110 kV+	No.	-	-	-	-	-	-	N/A	
HV	Zone substation switchgear	22/33 kV CB (indoor)	No.	-	-	-	100.00%	-	-	2	-
HV	Zone substation switchgear	22/33 kV CB (outdoor)	No.	11.76%	29.41%	5.88%	23.53%	29.42%	-	2	9.00%
HV	Zone substation switchgear	33 kV switch (ground mounted)	No.	-	-	-	-	-	-	N/A	
HV	Zone substation switchgear	33 kV switch (pole mounted)	No.	4.88%	43.90%	-	34.15%	17.07%	-	2	14.00%
HV	Zone substation switchgear	33 kV RMU	No.	-	-	-	-	-	-	N/A	
HV	Zone substation switchgear	50/66/110 kV CB (indoor)	No.	-	-	-	-	-	-	N/A	
HV	Zone substation switchgear	50/66/110 kV CB (outdoor)	No.	-	-	7.69%	61.54%	30.77%	-	2	-
HV	Zone substation switchgear	3.3/6.6/11/22 kV CB (ground mounted)	No.	-	3.70%	3.70%	20.37%	72.23%	-	2	
HV	Zone substation switchgear	3.3/6.6/11/22 kV CB (pole mounted)	No.	3.85%	-	-	92.31%	3.84%	-	2	

Appendix 4 –
Schedule 12a: Report on asset condition (continued)

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
HV	Zone substation transformer	Zone substation transformers	No.	-	-	4.35%	56.52%	39.13%		3	12.00%
HV	Distribution line	Distribution OH open wire conductor	km	0.67%	3..25%	20..23%	48.86%	26.99%		2	2.00%
HV	Distribution line	Distribution OH aerial cable conductor	km	-	-	-	-	-		N/A	
HV	Distribution line	SWER conductor	km	-	11.38%	60.24%	21.64%	6.73%		2	-
HV	Distribution cable	Distribution UG XLPE or PVC	km	1.62%	2.12%	14.19%	43.44%	38.63%		2	1.00%
HV	Distribution cable	Distribution UG PILC	km	-	-	2.12%	91.76%	6.12%		2	-
HV	Distribution cable	Distribution submarine cable	km	-	-	-	-	-		N/A	
HV	Distribution switchgear	3.3/6.6/11/22 kV CB (pole mounted) – reclosers and sectionalisers	No.	1.43%	2.14%	5.71%	51.43%	39.29%		2	4.00%
HV	Distribution switchgear	3.3/6.6/11/22 kV CB (indoor)	No.	7.89%	2.63%	2.63%	76.32%	10.53%		2	3.00%
HV	Distribution switchgear	3.3/6.6/11/22 kV switches and fuses (pole mounted)	No.	16.94%	19.07%	24.29%	26.92%	12.78%		2	2.00%
HV	Distribution switchgear	3.3/6.6/11/22 kV switch (ground mounted) – except RMU	No.	-	-	-	-	-		N/A	
HV	Distribution switchgear	3.3/6.6/11/22 kV RMU	No.	7.89%	7.68%	13.60%	30.92%	39.91%		3	4.00%
HV	Distribution transformer	Pole-mounted transformer	No.	0.20%	9.90%	32.38%	38.65%	18.87%		3	5.00%
HV	Distribution transformer	Ground-mounted transformer	No.	0.38%	6.84%	36.69%	37.52%	18.57%		2	5.00%
HV	Distribution transformer	Voltage regulators	No.	-	-	7.69%	26.92%	65.39%		3	-
HV	Distribution substations	Ground mounted substation housing	No.	0.31%	15.85%	40.50%	26.76%	16.58%		2	1.00%
LV	LV line	LV OH conductor	km	7.63%	51.59%	24.63%	13..13%	3.29%		2	2.00%
LV	LV cable	LV UG cable	km	-	0.87%	15.31%	30.32%	53.50%		2	1.00%
LV	LV streetlighting	LV OH/UG streetlight circuit	km	36.32%	12.10%	2.53%	18.49%	30.56%		2	1.00%
LV	Connections	OH/UG consumer service connections	No.	4.60%	4.80%	15.70%	33.20%	41.30%	0.40%	1	1.00%
All	Protection	Protection relays (electromechanical, solid state, and numeric)	No.	23.84%	14.24%	33.78%	27.48%	0.66%		1	25.00%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	30.68%	12.04%	23.69%	24.08%	9.51%		2	20.00%
All	Capacitor banks	Capacitors including controls	No.	-	-	-	-	-		N/A	
All	Load control	Centralised plant	Lot	-	42.86%	-	57.14%	-		2	10.00%
All	Load control	Relays	No.	-	-	-	-	-		1	-
All	Civils	Cable tunnels	km	-	-	-	-	-		N/A	

Note *CB = circuit breaker; HV = high-voltage; LV = low-voltage; OH = overhead; PILC = paper-insulated lead-covered; PVC = polyvinyl chloride; RMU = ring main unit; SCADA = supervisory control and data acquisition; SWER = single-wire earth return; UG = underground; XLPE = cross-linked polyethylene*

Appendix 4 –
Schedule 12b: Report on forecast capacity

12b(i) System Growth – Zone Substations

Exiting zone substation	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
Southbrook	39.7	Winter	40	N-1	No constraint	0.30	Winter	7	N-1	Winter	0	7.5	N-1	Security	2	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	MainPower is building a new zone substation (ZS) (Coldstream) east of Rangiora which will pick up the rapid load growth from Southbrook.
Burnt Hill	15.1	Summer	23	N-1 switched	No constraint	7.90	Summer	6.5	N-1 switched	Summer	4.9	7.5	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Swannanoa	18.2	Summer	23	N-1 switched	No constraint	4.80	Summer	4.4	N-1 switched	Summer	2.7	5.3	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	No constraint. Once Coldstream ZS is commissioned, Southbrook ZS can pick up some of the Swannanoa ZS load.
Amberley	6.3	Winter	6	N-1 switched	No constraint	0	Winter	2.5	N-1 switched	Winter	0	0	N-1	Security	1	Subtransmission circuit	Network upgrade	Implementation stage	Not applicable	Replacement ZS is being constructed due to capacity constraints and aging equipment. Backup subtransmission supply is limited to 6 MVA + 11 kV offload capability.
MacKenzies Rd	2.6	Winter	4	N	No constraint	1.40	Summer	0.6	N	Summer	0	0.4	N	Security	1	Subtransmission circuit	Distributed generation	Planning stage	Not applicable	Backup subtransmission supply from Culverden GXP not always possible. Engaging with local generation to help address constraint.
Greta	1.5	Summer	4	N	No constraint	2.50	Summer	2.2	N	Summer	2	2.3	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Cheviot	3.6	Summer	4	N	No constraint	0.40	Summer	0.2	N	Summer	0	0	N	Capacity	9	Zone substation transformer	Demand response	Planning stage	Not applicable	Flexibility solutions have been explored via market engagement but were not cost effective. Localised demand response will be further explored followed by network reinforcements to shift load.
Hawarden	3.9	Summer	4	N	No constraint	0.10	Summer	0	N	Summer	0	0	N	Capacity	5	Zone substation transformer	Demand response	Planning stage	> 3 years	Investigate load management/flexibility options in conjunction with network reinforcement to allow load shift. A project is budgeted in the 10-year period to upgrade the ZS capacity.
Ludstone	6.1	Winter	6	N-1 switched	Security	0	Winter	0	N-1	Winter	0	0	N-1	Security	1	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Ludstone ZS will be rebuilt on the Kaikoura ZS site. Flexibility options are being explored to improve security of supply.
Leader	1.7	Summer	4	N	No constraint	2.30	Summer	2.3	N	Summer	2.2	2.4	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint.
Oaro	0.2	Winter	0.5	N	No constraint	0.30	Winter	4.5	N	Winter	4.5	4.5	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Will be replaced with a new 4 MVA Substation as the subtransmission supply is being upgraded from 33 kV to 66 kV.
Mouse Point	17.8	Summer	13	N-1	Security	0	Summer	0	N-1	Summer	0	5.9	N-1	Security	1	Zone substation transformer	Network upgrade	Planning stage	Not applicable	ZS upgrade is budgeted for implementation in the 10-year period.
Hanmer	4.7	Winter	6	N	Security	1.30	Winter	0.7	N	Winter	0	0.9	N	Security	1	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	A new ZS will be constructed due to equipment aging and capacity. New local backup generation to improve security of supply.
Lochiel	0	Winter	0.3	N	No constraint	0.10	Winter	0.1	N	Winter	0.05	0.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint
Marble Quarry	0	Summer	0.2	N	No constraint	0.10	Summer	0.1	N	Summer	0.05	0.1	N	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	No constraint

Appendix 4 –
Schedule 12c: Report on forecast network demand

		Number of connections					
12c(i)	Consumer Connections	FY26	FY27	FY28	FY29	FY30	FY31
	Number of ICPs connected during year by consumer type						
	Consumer types defined by EDB						
	Residential	819	757	757	757	757	757
	Irrigation	32	30	30	30	30	30
	Large user	13	12	12	12	12	12
	Streetlights	1	1	1	1	1	1
	Other	–	–	–	–	–	–
	Connections total	**865**	**800**	**800**	**800**	**800**	**800**

	Distributed generation	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
	Number of connections made in year	299	376	400	424	448	472
	Capacity of distributed generation installed in year (MVA)	2	3	4	4	4	4

12c(ii)	System Demand						
	Maximum coincident system demand (MW)	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
	GXP demand	120	118	119	120	121	122
plus	Distributed generation output at high voltage and above	3	2	2	2	2	2
	Maximum coincident system demand	**123**	**120**	**121**	**122**	**123**	**124**
less	Net transfers to (from) other EDBs at high voltage and above						
	Demand on system for supply to consumers' connection points	**123**	**120**	**121**	**122**	**123**	**124**
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	660	666	670	675	680	684
less	Electricity exports to GXPs						
plus	Electricity supplied from distributed generation	29	30	31	32	33	34
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	**689**	**696**	**702**	**708**	**713**	**719**
less	Total energy delivered to ICPs	645	649	655	660	666	671
	Losses	**44**	**47**	**47**	**47**	**47**	**47**
	Load factor	**64%**	**66%**	**66%**	**66%**	**66%**	**66%**
	Loss ratio	**6.4%**	**6.7%**	**6.7%**	**6.7%**	**6.6%**	**6.6%**

Appendix 4 –
Schedule 12d: Report on forecast interruptions and duration

	FY26	FY27	FY28	FY29	FY30	FY31
SAIDI						
Class B (planned interruptions on the network)	177.5	169.6	169.6	169.6	169.6	169.6
Class C (unplanned interruptions on the network)	204.3	201.5	201.5	201.5	201.5	201.5
SAIFI						
Class B (planned interruptions on the network)	0.64	0.60	0.60	0.60	0.60	0.60
Class C (unplanned interruptions on the network)	1.25	1.23	1.23	1.23	1.23	1.23

Appendix 4 –
Schedule 13: Report on asset management maturity

Question No.	Function	Question	Score	Evidence-Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	MainPower's Asset Management Policy is documented, authorised by the CEO and Board Chair, and communicated to staff in various ways, including as part of the MPowered framework and the AMP.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	MainPower's Asset Management Strategy is aligned with its other policies and strategies, with an obvious downward cascade from Policy to Strategy. Stakeholder requirements are clearly understood and reflected in the Asset Management Strategy.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	MainPower's Asset Management Strategy reflects the recognised asset lifecycles of planning, design, construction, operation, maintenance, etc. The strategies include appropriate approaches for high-volume and low-volume asset fleets.		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	The Asset Management Plans for each asset class are based on the asset lifecycle, and take a risk-based approach to optimise performance, costs, and risks, which in turn defines interventions such as maintenance and renewals.		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).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	MainPower communicates its plans through both documentation (the AMP) and its induction procedures, which includes the MPowered framework.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Various documents ranging from the Delegated Authorities Policy through to job descriptions and reporting templates document what asset management outcomes people are responsible for.		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	MainPower's AMP includes 10-year spend forecasts, which are subject to an iterative process to smooth spending to within the revenue path and Service Corporation International (SCI) ratios. Future staff resourcing has been considered.		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.

Appendix 4 – Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	"The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy."	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	"The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy."	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	"The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc."	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
31	Asset management plan(s)	"What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)"	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	MainPower has many leading plans that seek to avoid emergency situations (e.g. design standards, construction standards), and many lagging plans such as incident management procedures, business continuity plans, and emergency recovery plans. These lagging plans are consistently linked to the Incident Management framework.		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.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Section 2.1.1 of the AMP shows how MainPower has assigned responsibilities to various roles, cascading downwards from the Board to the senior leadership team, whose responsibilities are described in the job descriptions.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	The AMP notes that processes exist for determining resources required for asset management activities.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	MainPower communicates the importance of meeting asset management outcomes through both leading controls (which range from design standards to job descriptions) and lagging controls (which range from practice reviews to inspection of completed works).		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	MainPower has a range of leading controls (e.g. design standards, material specifications, contract terms) to ensure compliant delivery of the Asset Management Strategy. These are complemented by a range of lagging controls that range from global (e.g. NZS7901 audits) to local (inspection of completed works).		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.
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	Job descriptions clearly define the asset management outcomes of roles, and show clear linkages to MainPower's values.		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.

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	"The organisation has not considered the need to put controls in place."	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Competency requirements (as reflected in job descriptions) are linked to asset management outcomes. There are comprehensive competency matrices in place for field staff.		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. (e.g., PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Field staff are subject to regular safety training and assessments. Engineering and asset management staff regularly attend training and up-skilling events (e.g. the Electricity Engineers' Association conference).		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.
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	MainPower communicates pertinent asset management information through a wide range of leading controls such as design standards, material specifications, and work quality expectations. At a more macro level, the MPowered way sets expectations of values and behaviours.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The AMP describes the main elements of MainPower's Asset Management System, and the linkages between those elements.		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. (E.g. s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Over time, the Asset Management Information System has been aligned to users' information requirements, as evidenced by the quality of asset management decisions.		"Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system."	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	MainPower is in the process of consolidating IT platforms, including mobile data functionality. Data quality and consistency has been reviewed and is considered sufficient to support future asset management.		"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.

Appendix 4 – Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

Appendix 4 – Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	MainPower's many business management frameworks reflect good industry practice and support users' decision-making requirements. A recent review confirms that data consistency is sufficient to support MainPower's decision-making.		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	The starting point for asset-related risks is MainPower's comprehensive risk management framework. The detailed consideration of risk cascades from the risk management framework, and takes inputs from a wide range of other planning processes, including long-term issues such as climate resilience through to safety bow-ties.		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 (e.g., 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	MainPower does allocate and reallocate resources in response to risk assessments and evaluations. The method of identifying options for risk mitigation and quantifying the benefits and costs of those options is considered robust.		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	In addition to MainPower's wide range of staff being generally aware of various statutory and regulatory requirements (through such means as reading, receiving bulletins, attending conferences, etc), MainPower uses ComplyWith to compile a compliance calendar and minimise the risk of overlooking an obligation.		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 (e.g., 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
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Leading controls such as design standards and material specifications reflect the expected performance, cost, and risk parameters of assets, and include the accumulated experience of MainPower's staff and the wider industry to ensure that completed assets reflect those performance requirements.		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 (e.g., PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	MainPower uses a wide range of leading controls (e.g. design standards, material specification) to minimise non-conformances, and complements this with a wide range of lagging controls (e.g. asset testing, AMMAT review, NZS7901 audits). These leading and lagging controls visibly link to the Asset Management Strategy.		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 (e.g., 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.

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/ incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
91	Life Cycle Activities	How does the organisation ensure that process(es) and/ or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/ or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	MainPower uses a wide range of leading controls (e.g. design standards, material specification) to set general asset performance and condition, and complements this with a wide range of audits and reviews (e.g. asset testing, AMMAT review, NZS7901 audits) to ensure that performance aligns with 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?	3	MainPower has systematic processes for assigning responsibility for investigating non-conformances, and taking remedial actions.		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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	MainPower has an Audit, Monitoring, and Compliance Management Plan that sets out the strategy for minimising non-compliances. This plan references a wide range of detailed audits and reviews across many areas of the business, including finance, safety, asset management, and industry participation.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	MainPower uses many leading controls (e.g. design standards, material specifications) to minimise non-conformances before they occur. Processes are in place for ensuring that actions aligned with the Asset Management Strategy result from investigation of non-conformances.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	MainPower's current asset management activities include various strategies and plans that examine practice areas and asset fleets to identify how performance, costs, and risks can be optimised.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	MainPower staff regularly attend industry events (e.g. the Electricity Engineers' Association conference), receive vendor information, seek advice on equipment (e.g. the external consultants ring main unit evaluation report), and receive recommendations on practice improvements (e.g. the Telarc NZS7901 audit report).		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 (e.g., 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.

Appendix 4 –
Schedule 13: Report on asset management maturity (continued)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	"The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."

Appendix 4 –
Schedule 14a: Mandatory explanatory notes on forecast information

Company Name: **MainPower New Zealand Ltd**
For Year Ended: **31 March 2026**

(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. Box 1 explains 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

In preparing the capital expenditure forecasts, MainPower has used the Westpac Economics Forecast Summary sheet October 2025 for the inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final periods of the AMP forecast.

	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Index	1.00	1.02	1.04	1.07	1.09	1.11	1.14	1.17	1.19	1.22

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. Box 2 explains 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

In preparing the operational expenditure forecasts MainPower has used the Westpac Economics Forecast Summary sheet October 2025 for the inflation (CPI) movements. The annual average inflation forecast for each year to the end of March has been applied to the AMP for the available forecast, and extrapolated at constant CPI for the final periods of the AMP forecast.

	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Index	1.00	1.02	1.04	1.07	1.09	1.11	1.14	1.17	1.19	1.22

Directors

Anthony Charles King	Chair
Janice Evelyn Fredric	Director
Jan Fraser Jonker	Director
Stephen Paul Lewis	Director
Murray James Taggart	Director
Hilary Walton	Director

Executive Leadership Team

Sean Horgan	Chief Executive
Sarah Barnes	General Manager Finance and Information Technology
Peter Cairney	General Manager Service Delivery
Penny Kibblewhite	General Manager Customer and Corporate Relations
Sandra O'Donohue	General Manager People and Culture
Sarah Barnes	Acting General Manager Commercial
Damien Whiffen	Chief Assets and Operations Officer

Registered Office

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Principal Banker

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China Construction Bank (New Zealand) Limited

Principal Solicitor

Duncan Cotterill
Christchurch

Auditor

Deloitte Limited Christchurch

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mainpower

Creating a smarter future to deliver local value.