For the disclosure year ending 31 March 2024

ANNUAL DELIVERY REPORT

Aurora
ENERGY

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1. INTRODUCTION

1.1. CONTEXT

Aurora Energy owns and operates the electricity network in Dunedin, Central Otago and Queenstown Lakes. It owns the poles, lines and equipment that distribute electricity from Transpower's national grid to more than 95,600 homes, farms and businesses. It is responsible for maintaining and renewing infrastructure, and the safety and reliability of electricity supply is a critical driver across all elements of our business.

In 2021, the Commerce Commission (Commission) approved a customised price-quality path (CPP) for Aurora Energy that enables investment of $563 million over five years (1 April 2021 to 31 March 2026 (CPP Period)) to address safety and reliability risk across the network.

Aurora Energy is subject to information disclosure regulation made under Part 4 of the Commerce Act 1986. The Commission regulates information that must be disclosed to stakeholders. Clause 2.5.5 of the Electricity Distribution Information Disclosure Determination 2012 (Determination) requires Aurora Energy to disclose an annual delivery report in relation to the delivery of its CPP. This annual delivery report (Annual Delivery Report) has been prepared pursuant to that clause for the period 1 April 2023 to 31 March 2024 (RY24).

On 31 March 2022, Aurora Energy disclosed the following three plans, which are referenced throughout this Annual Delivery Report:

- Safety Delivery Plan
- Project and Programme Delivery Plan (PPDP)
- Development Plan.

A copy of each plan is available at www.auroraenergy.co.nz.

References throughout this Annual Delivery Report to 'us', 'we' and 'our' are to Aurora Energy.

1.2. CONTENT OF ANNUAL DELIVERY REPORT

The content of this Annual Delivery Report is specified in the Determination. A matrix showing the relationship between the requirements set out in the Determination and the contents of this Annual Delivery Report can be found in Appendix A.

1.3. CERTIFICATION

This Annual Delivery Report was certified in accordance with clause 2.9.5 of the Determination on 29 August 2024. A copy of the Director's Certificate can be found in Appendix B.

1.4. ASSURANCE REPORT

Audit NZ has prepared an assurance report that meets the requirements of clause 2.8 of the Determination. A copy of that report can be found in Appendix C.

2. CHAIR AND CHIEF EXECUTIVE'S REPORT

We are pleased to present our Annual Delivery Report for the third year of our CPP, which outlines the progress during RY24 on our plans to deliver upgrades to the electricity network in Dunedin, Central Otago and Queenstown Lakes. Providing a safe and reliable electricity supply is a critical driver across all elements of our business.

The main priority for us throughout the CPP period is to deliver projects and programmes that will improve the safety of our network. At the same time, those projects and programmes will also over time improve the reliability of our network. Three years into our five-year CPP period, we are making good progress in the delivery of our CPP programme, noting that we continue to see strong growth in Central Otago which has again given rise to competing demands for resources and capital budgets, and the need to accelerate a number of growth-related investments.

In March 2022, we published the following three documents related to the CPP Period:

- Development Plan outlining business process-related improvement initiatives we planned to implement;
- Safety Delivery Plan outlining network asset-related safety improvements we planned to achieve; and
- Project and Programme Delivery Plan detailing projects and programmes that we planned to deliver.

As we incrementally and continually mature our practices and respond to changing circumstances, the resulting outputs and investment priorities have changed, and will continue to do so, as we progress through the CPP Period. Therefore, care is required in some cases when comparing progress against the plans. This is discussed further throughout this Annual Delivery Report, and an up-to-date view of our work programme can be found in our 2024 Asset Management Plan.

During RY24 we continued to experience global supply chain pressures (including material availability and shipping delays) and escalating costs. These external factors caused us to adapt our procurement processes in an attempt to reduce our exposures to equipment/material supply delays and new asset construction cost escalation.

Our improving procurement processes are helping us to mitigate upstream supply-side constraints, but the competing growth versus renewal demand impact continues to make it more difficult to deliver the asset replacement quantities we had originally planned. We continue to prioritise the replacement of those assets within our safety sensitive fleets that have the lowest asset health ratings.

The reduced renewal quantity impact of supply chain and inflationary pressures continues to be partially offset in some network asset fleets by new favourable asset inspection information as we continue to mature our network risk assessment practices, which are discussed further in section 5.

This continues to result in a reduction in the quantum of the asset renewal backlog and forecast assets requiring renewal. Improvements that we continue to make in this space have enabled us to reassess which assets need to be renewed or replaced. Through a combination of these improvements and renewals undertaken during RY24, we have been able to successfully reduce our reported network risk for the following safety-sensitive fleets to lower than which we had forecast in our Safety Delivery Plan at this point of the CPP Period:

- Poles
- Subtransmission and low voltage conductor
- Cables (including cable terminations involving cast-iron potheads)
- Ground mounted distribution transformers
- Pole mounted distribution transformers.

Conversely, some network fleets are showing moderately higher than forecast levels of safety risk, such as our crossarm and distribution conductor fleets, which will continue to be a focus as we progress through the CPP Period.

We are also reporting higher than forecast risk for our ground mounted switchgear fleet. This is potentially the result of a conservative view of obsolescence and the resulting health/condition score of oil filled switchgear, but we felt it prudent to apply a conservative approach until information supports an alternative assessment. We will continue with our extensive maintenance and renewal programme and will continue to report updated health/condition and risk as we progress through the CPP Period.

Overall, the delivery of our safety risk reduction plan remains on track with some fleets ahead of forecast and others requiring reprioritised focus to address newly identified defects during our cyclical inspection programme. We expect this theme of new inspection information leading to an annual reprioritisation of the plan to continue as we progress through the CPP Period. Our current network safety risk profile is discussed further in section 4.

In relation to poles specifically, we are pleased to report that we are on track to eliminate the backlog of orange-tagged poles by the end of 2024 so that we can focus on continuing to remain compliant as new red and orange tagged poles are identified through our five-year inspection cycle.

We continue to remove cast iron cable terminations (potheads) from the network, with priority given to cast iron potheads in highly populated areas. Only 3 zone 1 (highest public safety zone classification) potheads remained on the network at the end of RY24. The overall programme to remove 375 cast iron potheads is approximately 70% complete with 105 remaining on the network. We are on track to complete this programme of work within the CPP period.

In the Dunedin area, we have strengthened the electricity supply for customers in Andersons Bay and the lower Otago Peninsula community with the completion of our renewal and upgrade to the Andersons Bay zone substation. Work to review the Green Island zone substation is well under way with civil works having commenced in January 2024.

We had planned to complete the Smith Street to Willowbank inter-tie in RY24. Due to delays in the Dunedin City Council's major city upgrade project, this will now be completed in RY26 to tie in with the commissioning of the new switchgear at the Smith Street zone substation. Trenching and cabling is well underway. We had also planned to complete the new Omakau zone substation in RY24. Due to competing priorities, the delivery of this project has been delayed and will now be completed in RY25.

Our CPP Period plan and associated work programme has required a significant increase in work, and we remain committed to delivering that work in a prioritised manner as efficiently and effectively as possible. Initiatives that we are implementing to further improve our asset management practices and deliver more efficiently can be found in section 5. In particular, we are continuing to bundle work packages where possible and have started combining relevant fleet capital projects on feeders off a zone substation into a single programme of work.

We have recently reset our field service agreements for the period RY25 to RY29 and included within those are an enhanced set of unit rates for volumetric work. We have also developed a project cost estimation stage gate process and tool that was used to develop our 2024 AMP forecasts.

We continue to train our staff in the Prince2 methodology so that we can consistently manage project related risks and deliver our projects to schedule. We have progressed the development of our new asset management software (Maximo), which will systemise our long-term asset management solution, including enhanced tracking of asset defects, condition and risk, and deliver efficiency gains and benefits to customers. Creating a more comprehensive and single source of asset data will help to ensure that we are making informed and timely asset renewal and maintenance decisions.

Looking ahead to RY25 we remain committed to our network safety focussed work programme which is broadly progressing to plan. However, growth remains strong in the Central Otago and Queenstown regions and we continue to see a growing focus on decarbonisation through electrification. Consistent with the work delivered already during the CPP Period, our RY25 plan accelerates some urgent growth projects. We have sought additional capital expenditure approval from the Commerce Commission to progress urgent customer connection and growth-related network expansion and are awaiting their final decision. Approval of this additional capital expenditure will support our continuing plan to deliver safety-related asset renewal work.

We are fortunate to have a dedicated team at Aurora Energy and it is thanks to their hard work and customer-first approach that we have made such good progress on our five-year investment plans. They always remember there is a person or business at the end of the line.

Our contracting partners are pivotal in supporting us to deliver our commitments and we thank them for working at all times of the night and day and in all weather conditions to keep the lights on.

Steve Thompson	**Richard Fletcher**
Chair	Chief Executive

3. WHAT WE HAVE DELIVERED

Our PPDP detailed the capital expenditure and operational expenditure projects and programmes that we planned to deliver throughout the remainder of the CPP Period. That plan has formed the basis of our work plan for RY22 through to RY26, along with any adjustments reflected in our subsequent asset management plans (AMPs).

As mentioned in section 2, our ability to deliver at the elevated levels planned throughout the CPP Period continues to be under pressure from global supply chain pressures and escalating costs, together with financial resource constraints. Skill shortages is an emerging area that we are managing. In addition to these external factors, strong growth in Central Otago continues to require re-allocation of contractor resources and capital budgets to meet higher than forecast levels of customer driven growth projects in RY24. We are focussing on delivering those parts of our plan that will improve the safety of our network, while at the same time meeting the increased demand from communities reliant on our network for their future electricity supply.

During RY24, we continued to receive new favourable asset inspection information in some fleets and maintained our focus on maturing network risk assessment practices. This has enabled us to reassess which assets need to be renewed or replaced, and to flex our asset replacement and renewal programmes accordingly.

In this section, we outline the key capital expenditure and operational expenditure projects and programmes in the PPDP that we:

- have not yet completed, but which are on schedule in accordance with the PPDP
- delivered on time in RY24
- have not completed on time, but had planned to complete in RY24.

Projects and programmes not yet completed, but on schedule to complete

In RY24 we made progress on each of the following capital expenditure projects, which are still on track to be completed in line with the timeframes in the PPDP:

- **Upper Clutha auto transformer replacement:** The detailed design for enabling works and procurement of the auto transformer is complete. Commissioning of the new transformer will occur in October 2024.
- **Frankton zone substation upgrade:** This project is progressing to plan with equipment having been ordered and currently being shipped to New Zealand.
- **Riverbank new transformer**: The design is underway for the new transformer and associated switchgear.

Our capital expenditure and operational expenditure programmes are integral to the operation of our business throughout the five-year CPP Period and beyond. We have continued to focus on the delivery of these programmes in RY24. Cost escalation, global supply pressures (including material availability and shipping delays), and the re-allocation of resources to other priority work has impacted our ability to deliver zone substation renewals and ground mounted switchgear to the extent we had planned in RY24. The rebuild and upgrade of the Andersons Bay substation was completed in RY24. Further detail about our expenditure and the assets we are delivering in our asset replacement and renewal programme compared to that which we forecast in our PPDP can be found in section 8.

Projects and programmes delivered on time in RY24

In RY24 we delivered the following projects and programmes as planned in the PPDP:

- **Lindis transformer fans installation:** This will enable the Lindis Crossing transformer to meet the future demand load until a further upgrade occurs in the region with either a second transformer at Lindis Crossing as currently planned or an upgrade at Queensbury in RY27 to accommodate new growth information.
- **Arrowtown 33kV Ring Upgrade:** The installation of a new 33kV underground cable to connect Frankton GXP to Coronet Peak Zone Substation via Lower Shotover Road was completed. This will provide increased capacity and greater security of supply for the community and reduce the risk of significant outages in the area.
- **New Arrowtown substation (feasibility study)**: This initiative entailed undertaking a feasibility study to determine whether land was to be purchased for a new Arrowtown zone substation. The feasibility study was completed in RY23 and , a decision has been made not to purchase land in Arrowtown township. Load and capacity issues will instead be accommodated by the new Dalefield substation in RY27 and a new Arrowtown zone substation will be considered in the latter part of the 2024 AMP ten-year plan.

In addition to the above:

- the Upper Clutha voltage support project that was planned for delivery in RY23, has now been completed; and
- the Upper Clutha special protection scheme project that was planned for delivery in RY25 has been completed ahead of time.

Projects and programmes we have not completed on time, but had planned to complete in RY24

- **Smith Street to Willowbank Inter-tie**: We are creating a ring network to improve the security of electricity supply for the approximately 5,900 customers supplied by the Smith Street and Willowbank substations. Work was coordinated with the Dunedin City Council's centre city upgrade, the timing of which impacted on our ability to deliver within the timeframe initially planned in the PPDP. Work on the final stage of this project has commenced and will be completed in RY26 to tie in with the commissioning of the new switchgear at the Smith Street zone substation. .
- **Omakau New Zone substation**: While we have installed the new transformer and completed the landscape planting, the need to balance competing growth priorities within the Central Otago region means that this project will now be completed in RY25.

We have continued to progress the implementation of a new asset management system. The dedicated implementation team launched stage one of the system in April 2024.

There are no key capital expenditure or operational expenditure projects or programmes that we had planned to commence that did not get underway in RY24.

4. SAFETY

4.1. PROGRESS AGAINST OUR SAFETY DELIVERY PLAN

In March 2022 we published a Safety Delivery Plan, which detailed how the delivery of our CPP period capital and operational expenditure projects and programmes is expected to reduce our network safety risks.

We recognise two parts of network safety risk:

- Safety of public
- Safety of personnel.

Our Safety Delivery Plan outlines the key network safety risks and the actions we plan to take to reduce those risks during the CPP Period, with reference to the principle of reducing risk to 'as low as reasonably practicable'.

4.1.1. Improving risk practices

As we progress through the CPP Period, we are continually improving our asset management practices, which is subsequently enhancing our understanding of asset condition and our ability to quantify risk. These commitments were documented in our Development Plan. We report on progress in relation to Asset Management practices and processes, against our Development Plan including safety risk in section 5.6.

As we incrementally and continually mature our view of asset health and risk quantification, the resulting outputs will change. Therefore, care is required in interpreting the movement in asset fleet health and risk scores through the CPP Period.

At the time of preparing the Safety Delivery Plan, we used a predominantly age-based approach in decerning a baseline view of asset health. As we embed improvements, such as shifting to a condition-based approach, we have and will continue to see a refined view of Asset Health and thus risk.

In RY23 we reported that we were focusing on gathering updated condition information related to our assets. This has continued into RY24 and means that we can be very specific about which assets are of H1 health and in which public safety criticality zone they are located. New condition information related to an asset can add or remove years to / from the previously age-based asset fleet profile life. During RY24 we undertook a review of our inspection programmes for our overhead network, distribution transformers, LV enclosers and ground mounted distribution switchgear. In October 2023, we rolled out a new overhead inspection programme which broadened the focus beyond just poles to all overhead assets. The enhanced inspection programmes for distribution transformers, LV enclosures and ground mounted distribution switchgear will be fully implemented during RY25.

In recognition of some limitations of visual inspections, we have implemented advanced inspection techniques on a risk-based approach. This includes thermal, acoustic, and aerial inspections. We will maintain a balance between the cost and return on investment (defect discovery rate) from these advanced inspection techniques, ensuring they are only deployed as appropriate/necessary.

We have documented fleet strategies and plans for our safety critical fleets, which include plausible failure modes. These documents enable a structured and evidence-based approach to investment decisions. The identified maintenance and renewal activities are informed by our understanding of failure modes and our improving view of condition-based health. Incremental improvements are being made to how we model asset health, by fleet and are captured in the fleet strategies.

We have started to apply root cause analysis to enable us to respond effectively to asset failures. By understanding why an asset failed, we can take actions to prevent future occurrences of the same nature, e.g. updating inspection programmes, design standards, material standards etc.

In addition to adjustments to expected asset lives, inspection informed asset condition scoring and targeted asset renewals, our asset health profile is also improved by the renewal of associated assets (for example a primary reconductoring job may replace several support structures as well, which are considered associated assets). This changes the overall fleet health, which improves the risk profile.

4.1.2. Change in network safety risk

Asset health

We calculate the total network risk as the sum of individual asset risks for fleets with public safety risk potential. Figure 1 below compares the percentage of the assets in each safety-sensitive fleet that have an H1 health rating asset as at 31 March 2024 with the forecast percentage in the Safety Delivery Plan. As described above, the result is a function of both the delivery of our capital and operational expenditure projects and programmes, and our maturing risk assessment practices.

Figure 1: Percentage of H1 assets within safety-sensitive fleets

SAFETY SENSITIVE FLEET	START OF RY22 H1%	END OF RY23 FORECAST H1%	END OF RY24 ACTUAL H1%
Protection	48%	29.40%	48.61%
Indoor Switchgear	38%	33.40%	19.42%
Subtransmission Conductor (km)	14%	10.70%	12.75%
Crossarms	18%	17.20%	27.86%
LV Conductor (km)	17%	19.90%	12.35%
Poles	12%	9.60%	3.46%
Distribution Conductor (km)	6%	5.35%	3.12%
Power Transformers	11%	10.60%	2.90%
Outdoor Switchgear	21%	9.50%	2.25%
Ground Mounted Switchgear	9%	6.30%	0.35%
Pole Mounted Distribution Transformers	13%	15.00%	4.39%
Low Voltage Enclosures	11%	11.80%	10.38%
Subtransmission Cables (km/units*)	9%	8.80%	0.00%
Reclosers and Sectionalisers	10.53%	15.79%	0.00%
Ground Mounted Distribution Transformers	4.56%	5.79%	0.21%
Pole Mounted Switches	40.89%	42.18%	14.93%
Distribution Cables (km/units*)	2.44%	0.89%	0.02%
LV Cables (km/units*)	2.18%	3.12%	0.78%

We have made significant progress across the network in improving the health of safety-sensitive fleets, with the health of some fleets progressing ahead of our plan/forecast. For some fleets, however, we will need to reprioritise our plan for the remainder of the CPP Period (and beyond) to ensure that we meet our objective to reduce safety network risks as soon as practical.

At the beginning of the CPP Period, we estimated that 48% of all protection relays were in the H1 category. Our Safety Delivery Plan forecast this figure to decrease to 29.4% by the end of RY24. However, our current data/records, which we continue to improve, now show that, as at 31 March 2024, 48.6% of our relays are in the H1 category. On first impression this trend may be of concern, though as we reported last year, there are two factors influencing this result:

- Modern protection scheme solutions often require a reduced number of relays. For example, a modern 11kV numerical protection relay will typically displace two older electromechanical relays on average. This reduction in relay count impacts the percentage scoring outlined above as a significant number of electromechanical relays continue to be removed.
- The completeness and accuracy of our protection relay data has improved including the identification of additional relays through the integration of data into our new asset management software.

Protection replacements have been recently completed at the Andersons Bay, Roxburgh and Outram zone substations as a part of wider scopes of zone substation renewal works. Protection replacement is presently underway at Alexandra, Green Island, Omakau, Queenstown, and Smith Street zone substations as part of wider renewal work at these sites, and at Fernhill zone substation as a stand-alone protection project. At the time of writing, protection upgrades had recently been completed at the Remarkables zone substation.

We remain committed to our protection renewal program and are confident of making substantial progress through the CPP Period toward our initial target of 7% of the fleet being H1 at the end of RY26. Several planned protection projects are now integrated into the scopes of larger renewal projects, and as such, protection replacement progress is dependent on projects to renew major primary plant at zone substations.

At the beginning of the CPP Period, we estimated that 18% of all crossarms were in the H1 category. Our Safety Delivery Plan forecast this figure to decrease to 17.2% by the end of RY24. However, the output of our current asset health index model, using updated condition information, shows 27.86% of the fleet at H1 as at 31 March 2024. The new improved inspection process and systems are supporting revised assessments that neither the age-based forecast health, nor the previous predominately pole focused inspection programme provided. Through these improvements we expect to gain a more accurate health profile for cross-arms. Early indications from the improved inspection data are that we will see a shift away from H1 and H2 assets, but we do not yet have a sufficient quantity of data to update the assumptions around useful life in the age-based model.

In some cases, our maturing risk practices have resulted in a revised view of the risk profile of a fleet. At the beginning of the CPP Period, we estimated that 9% of the ground mounted switchgear fleet was in the H1 category. Our Safety Delivery Plan forecast this figure to be 6.3% by the end of RY24. However, the output of our current asset health index model shows that 0.35 % of the fleet is at H1 as at 31 March 2024. In reviewing the fleet strategy and asset health index model for ground mounted switchgear, we have revised how we treat obsolescence, resulting in a change in the health forecast. As mentioned above, in RY25 we will also introduce a new inspection programme for this fleet. We have also initiated the trial of a non-destructive test method, which will be used to inform future health grading. We will continue with our extensive maintenance and renewal programme for oil filled switchgear, informed by our fleet strategy and continuous review to take account of asset condition (inspection/maintenance programme), plus performance information through root cause analysis (RCA) and subsequently identified emerging issues.

As low as reasonably practicable

While our asset renewals programme continues to prioritise fleets with the highest inherent and/or residual risk on the network, we also continue to replace a modest level of assets in most lower safety risk fleets where asset health indicates an end-of-life asset, thereby addressing other risk types such as reliability. These practices support our 'As Low As Reasonably Practicable' (ALARP) approach to safety. A detailed explanation of our intervention strategies for end-of-life assets, is set out in our 2024 Asset Management Plan.

We consider a number of risk management strategies to achieve ALARP safety risk. ALARP or similar phrases are widely used in safety regulation. When following the ALARP principle to safety management, an organisation will implement or execute all reasonable actions to reduce safety risk. When ALARP has been achieved, the cost or effort of all remaining possible actions to reduce safety risk will be disproportionate to the safety benefit gained.

When making a choice between the implementation of different risk controls it is important to understand their effectiveness. As outlined in our Safety Delivery Plan, we consider a hierarchy of controls:

- **Eliminate**: removal of asset; this strategy is mostly unpracticable for existing network assets providing a required function/purpose
- **Substitute**: asset relocation to a safer location or replacement with a safer option; this is the most effective strategy available for Aurora Energy
- **Engineering**: asset maintenance, improvement of design standards, addressing specific failure causes; we will use this strategy as a complimentary measure to the more effective Substitute
- **Administrative**: procedures for delivery of planned works; public awareness campaigns; emergency response procedures; this is a complimentary strategy.

Risk tolerance

Figure 2 below sets out the number of assets in that fleet that are above the risk tolerance line of our corporate risk matrix as at 31 March 2024, while Figure 3 depicts this as a percentage.

Not all safety sensitive fleets depicted in Figure 1 above are able to be 'risk quantified'. Fleets which are unable to be 'risk quantified' have been excluded from Figure 2 and Figure 3 below.

Asset risk is the product of the likelihood of a failure occurring with the consequence of the failure mode. Our approach to risk quantification considers asset health as a proxy to likelihood of failure, alongside of asset criticality as a proxy to the consequence of failure. Within this framework we calculate asset safety impacts depending on the location of assets within safety zones implemented in our geospatial information system.

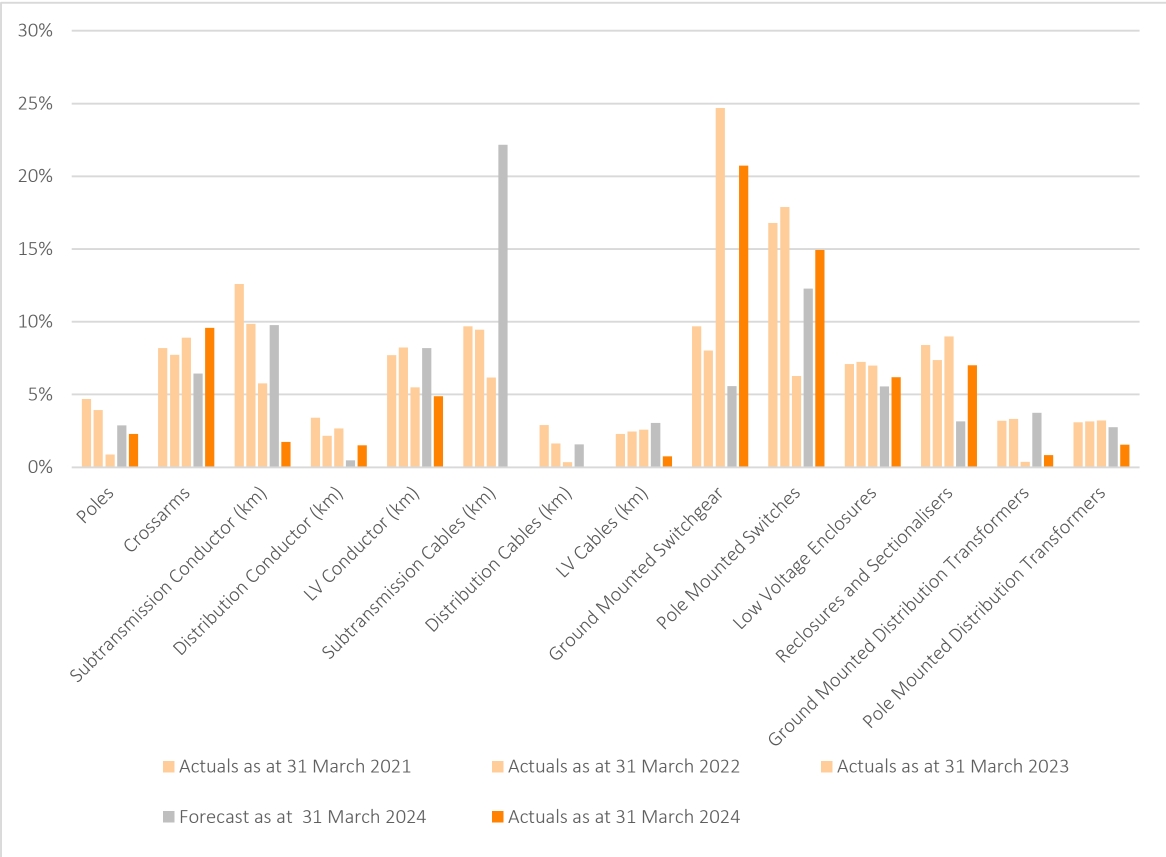
Consistent with our Risk Control and Management Standard, the corporate risk matrix assesses asset risks with a potential safety impact of more than 'moderate' and a likelihood rating of 'possible' or higher, as above our risk tolerance level.

Figure 2: Number of assets within a safety-sensitive fleet above risk tolerance level

SAFETY SENSITIVE FLEETS	NUMBER OF UNITS ABOVE TOLERANCE				
	ACTUALS AS AT 31 MARCH 2021	ACTUALS AS AT 31 MARCH 2022	ACTUALS AS AT 31 MARCH 2023	FORECAST AS AT 31 MARCH 2024	ACTUALS AS AT 31 MARCH 2024
Poles	2487	2089	461	1531	1226
Crossarms	7664	7209	8488	6015	9189
Subtransmission Conductor (km)	66	51.5	29	51	9
Distribution Conductor (km)	76	49.2	60	11	35
LV Conductor (km)	72	76.8	51	77	50
Subtransmission Cables (km)	8	8.2	5	19	0
Distribution Cables (km)	32	18.5	4	18	0
LV Cables (km)	23	25.4	27	32	9

Ground Mounted Switchgear	199	164	340	114	296
Pole Mounted Switches	197	210	63	144	191
Low Voltage Enclosures	1102	1113	1111	853	1051
Reclosures and Sectionalisers	8	7	9	3	8
Ground Mounted Distribution Transformers	101	106	12	119	28
Pole Mounted Distribution Transformers	120	123	126	107	63

Figure 3: Percentage of safety-sensitive fleet above risk tolerance level



We have been unable to reduce the safety risk for six of our safety-sensitive fleets to the extent that we had planned to as at 31 March 2024:

- **Crossarms**: During RY24, we implemented an enhanced inspection regime for crossarms on our network. Early indications from the latest inspection data show a significant improvement in the health of our crossarm fleet, supporting our decision to defer renewals until better condition data is available. Under the new overhead inspection programme, 14% of crossarms inspected that had previously been considered grade H1 (informed by age/pole inspection data), have been re-classified as grades 4 and 5. We will not have a complete data set until we complete the full 5-year inspection programme, however we will continue to monitor the discovery of H1 and H2 crossarms and, if required, will prioritise acceleration of the renewal programme to address associated safety-related risks.

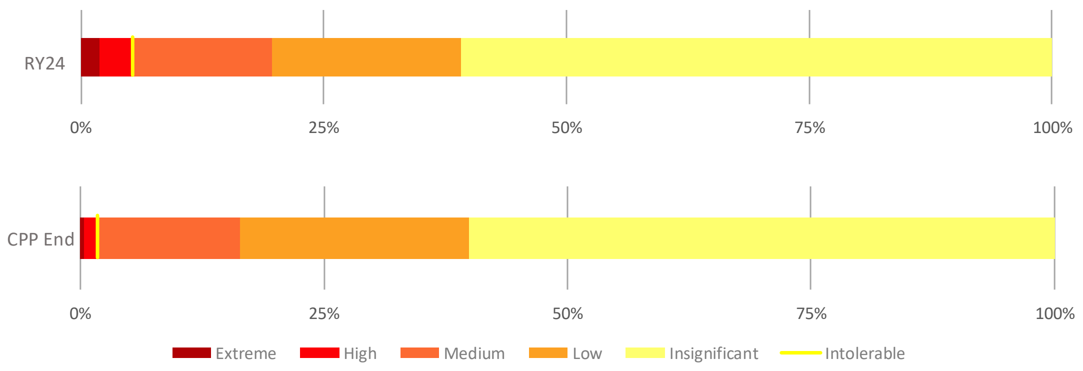
- **Distribution conductor**: Our new overhead inspection programme will enable us to validate data and improve confidence in our risk-based approach to renewals within this fleet. We continue to progress our replacement programme, which is risk prioritised and informed by known conductor type issues and validated by our RCA learnings. We will be in a position to revise timeframes within which we plan to reduce this risk as our inspection programme progresses.
- **Ground mounted switchgear**: We have made significant progress on our oil filled ring main unit major maintenance programme resulting in greater confidence that the life of these assets could be extended in some cases. The number of H3 assets makes up a significant portion of the units above risk tolerance. Typically at H3, switchgear has an assessed remaining life such that renewal is signalled but not expected until the latter part of our 10-year plan, i.e. it is not urgent. In RY25 we will stand up a new inspection programme to compliment the current maintenance activities. The health models will be updated to reflect the data obtained.
- **Pole mounted switches**: in RY23 we undertook a desktop data review and cleansing exercise. As of RY24, pole mounted switches will be inspected, including use of thermal imaging, as part of the new OH inspection programme. This information will be used to inform a more robust, risk prioritised asset renewal programme.
- **LV enclosures**: The variance between actual and forecast is minor, and we still expect to achieve the expected risk forecasts for these fleets throughout the remainder of the CPP Period.
- **Reclosers and sectionalisers**: We have undertaken a desktop review of data for this fleet, and are in the process of rolling out thermal imaging inspection as part of the overhead inspection programme. It is expected that under the current investment plan, the majority of H1 and H2 assets will be replaced during the CPP period. The high number of assets above risk tolerance is inclusive of H3 assets, which we would not expect to replace for 5-10 years.

Across our overall programme, several factors influenced our ability to achieve our forecast risk reduction, including:

- The re-allocation of contractor resources and capital budgets to meet higher than forecast levels of customer driven growth projects in RY24.
- Cost escalation has exceeded the forecast used when setting our CPP allowances. This has meant that the capital expenditure allowances are not sufficient to complete all works as forecast in the PPDP. We will continue to prioritise our renewals to best manage the impact of cost escalation on our planned risk reduction targets.
- Global supply chain issues have impacted the delivery of some projects and programmes. Note that this has not impacted the overall capital expenditure which has been transferred between projects and programmes to ensure that the overall plan is being progressed to the extent possible within the regulatory allowances. We have adjusted our procurement lead times for specific assets where supply is constrained as we progress into RY25.

Our revised view of the total network critical safety risk change as at 31 March 2024 is illustrated in the following figure:

Figure 4: Total network asset risk profile change



4.2. SAFETY-RELATED INCIDENTS

Safety is our top priority, and we are focused on identifying, reviewing and, as necessary, taking corrective action regarding safety-related incidents on our network.

In section 8, we report on the number of safety-related incidents in each of our pricing regions. The total number of safety-related incidents reported for RY24 is higher than for RY23. Specifically, there was an increase in the Dunedin region, no change in Central Otago and Wānaka, and a decrease in the Queenstown region.

In RY24 we made improvements to the capture, classification and reporting of safety-related incidents making it easier to classify events when they happen as well as providing additional insights into historic data. This reclassification has revealed that we have been reporting the summation of incidents, near misses and uncontrolled hazards in our previous figures. We have continued this approach this year to ensure trends remain comparable, but it is relevant to note that the near miss and hazard reports are in effect leading indicators and opportunities for improvement before an incident occurs. We also conduct regular triage of events to ensure that meaningful data is collected. In RY25, we plan to transition incident management and reporting to a new software platform aligned with our risk management framework.

Third-party contact with our assets remained the primary type of safety-related incident on our network in RY24. Other key contributors to safety-related incidents during the year were asset failure, field service provider work activities and vehicles.

Third-party contact with our assets includes vehicles hitting poles or service enclosures, external contractor cable strikes and contact with overhead lines. Third-party contacts accounted for 35% of all reportable incidents in RY24 and were the main contributor to the overall increase in safety incidents in the Dunedin region compared to RY23.

Recognising the significance of third-party contact in safety related incidents, we have reviewed and updated our proactive advertising campaign across various media channels to promote public safety around our assets. Our campaign emphasises public safety messages such as staying away from fallen power lines, securing loose trampolines before high winds, contacting Aurora Energy before undertaking work around our assets and using beforeUdig, the online service for information on the location of underground utilities. This public safety campaign, now tagged 'Be switched on to safety', encourages the public to always 'be switched on' to the risks surrounding the electricity network and to remind them to stay safe. The new campaign better aligns the sequencing of our safety messages with the seasons so that they have maximum relevance, for example fire risk messaging being timed for the onset of summer. The new campaign is scheduled for launch in early RY25.

The number of incidents involving asset failure has increased on last year, with no obvious trend in failure mode or asset class. We continue to make improvements in how information is captured in the field and in our processes for investigating and establishing root causes. We expect the learnings from root cause analysis will reduce the risk of repeat failures over time.

We maintain a defects app for use by Aurora Energy staff and our field service providers. The app enables reporting of any asset defects identified on our network from the field outside of our standard scheduled maintenance and inspection cycles, including those that pose a safety risk. Any reported defect can be assigned to our rapid response team for risk assessment and follow-up action where required.

We are committed to the safety of field service providers and Aurora Energy staff working in the field. Most incidents related to contactor work activities during RY24 were minor slips, trips, strains or sprains and reflect an ongoing focus on the reporting of all minor incidents, near misses and hazards from our field service providers.

We continue to proactively engage with our field service providers to ensure their staff have the required competency to work safely on our network and that they are providing the necessary training to their staff. In RY24, we appointed a competency and audit adviser to our safety team to support the auditing and compliance of our approved field service providers with safe work practices and to facilitate safety observations on the network. We also:

- Host engagement forums with our field service providers twice a year at which safety-related matters are discussed, including the management of sub-contractors
- Require our field service providers to have robust systems in place to manage competency of their staff and any sub-contractors they engage
- Collaborate across our industry, with the Electricity Engineers Association, Electricity Networks Association, and other electricity distribution businesses to implement a common competency framework to improve clarity and transferability of qualifications and competency of field staff
- Undertake regular audits of our field service providers to verify their competency assurance processes
- Share safety alerts with our field service providers and approved contractors when an incident or near miss occurs so that all contractors can learn from these experiences.

Vehicle related incidents include instances where members of the public intrude onto field service provider worksites as well as driving incidents on public roads. To improve traffic management practices, we actively engage with councils in our region. Our goal is to reduce the number of vehicle impact related events on the network. We have received feedback from councils and will continue exploring opportunities for coordinated efforts.

Two areas where we have seen incidents reduce in RY24 are in vegetation management and network operations.

Encroaching vegetation can cause damage to equipment and disrupt power. To reduce vegetation-related incidents, we follow a systematic inspection regime of vegetation across our network. We conduct inspections on a three-year cycle, with critical areas (such as fire-prone zones and those with significant vegetation-related issues) receiving 12-month inspections. These ongoing efforts have resulted in a reduction in these incident types in RY24. We are currently reviewing our approach to vegetation management including the role of emerging technologies to help us to better target vegetation control activities.

Our focus on reducing the number of network switching related safety incidents that occurred in RY23 via safety days and refresher training resulted in a halving of these incident types in RY24. We see this as an important and significant improvement. We are continuing to undertake regular reviews within our network operations team where we share insights from network-related events and identify opportunities to keep improving our planning and execution practices.

5. DEVELOPING OUR PRACTICES

In March 2022 we published a Development Plan, which detailed how we planned to improve our business practices in certain areas throughout the CPP Period. We set out in the Development Plan the planned initiatives for the remaining years of the CPP that will result in Aurora Energy achieving its defined objectives for specific areas by the end of the CPP period.

In this Annual Delivery Report, we provide a summary of the progress that we are making in each of these areas and have assessed ourselves on a scale of 1 to 5 as to how well we are tracking based on the delivery of the planned initiatives in the Development Plan. We report on these in each of our Annual Delivery Reports.

What do our ratings mean?

- **1 – Not started:** no planned activities/initiatives have started
- **2 – Not achieved:** no planned activities/initiatives have been achieved
- **3 – Partially achieved:** less than 50% of planned activities/initiatives have been achieved
- **4 – Largely achieved:** 50% or more of planned activities/initiatives have been achieved, but not 100%
- **5 – Achieved/Exceeded plan:** 100% of planned activities/initiatives have been achieved or are progressing ahead of schedule

Our self-assessment rating is measuring delivery of our planned initiatives in each regulatory year. The rating does not assess our position in relation to our final goal at the end of the CPP period, but rather where we are, year-on-year, in delivering what we say we will deliver and therefore whether we are on track for our final goal.

5.1. ENSURING THE PUBLIC UNDERSTANDS ELECTRICITY PRICING

The way electricity pricing is set is changing, and we want to help customers understand these changes and what it means for them.

How prices are set for each pricing region (Dunedin, Central Otago and Wānaka, and Queenstown) is outlined in our pricing methodology which is published on our website. We evolve and update our pricing methodology each year in alignment with our pricing strategy, to make things easier for customers to understand.

> We rate ourselves 5/5 for ensuring that the additional information that we disclose in our pricing methodology enables interested persons to understand how we set prices for each of our pricing regions.

We have rated ourselves this score because we have continued to publish the additional information in our pricing-related disclosures and have subsequently refreshed the information in our latest pricing methodology which we disclosed in March 2024. The additional information enables interested persons to understand how we set prices for each of our pricing regions, including a worked example of how an average domestic customer's price would be calculated in each pricing region. In addition, we have published our cost of supply model with supporting explanatory material on our website which shows how costs are allocated to each pricing region.

We continue to make progress against the pricing strategy and roadmap that we published in April 2021. The pricing strategy includes initiatives to make electricity pricing simpler and improve the cost-reflectiveness of prices. We expect our pricing strategy will be fully implemented by 2027.

During RY24, we have:

- **Published our Long-Run Marginal Cost (LRMC) approach:** Our published LRMC approach transparently demonstrates our rationale and calculations that support our Time-of-Use tariffs (ToU) in each pricing area. Control tariff options have been consolidated into a single control tariff in each of the pricing areas. This change helps to simplify the pricing structure to enable customers to better understand and respond to pricing signals.
- **Improved information on our website:** We regularly refresh information on our website to further explain electricity pricing and provide answers to commonly asked questions. Our website refresh in RY24 included the addition of an animated explanation of ToU prices to help customers understand and respond to new ToU prices.
- **Continued to engage with key stakeholders:** We take the opportunity to attend key stakeholder forums, such as the Central Otago Grey Power Annual General Meeting in Alexandra, which we attended in May 2023, to promote better understanding of pricing and to make ourselves available to answer any questions.

5.2. LOW VOLTAGE NETWORK PRACTICES

Voltage limits are regulated to ensure satisfactory power quality levels can be achieved for customers. We are working on ways to continue to improve how we monitor power quality to identify emerging trends including the identification of locations requiring power quality improvement, and do what we can to remediate them.

We rate ourselves 4/5 for developing our low voltage network practices during RY24.

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Reacting to monitoring					
Monitoring to anticipating					
DTM Programme and Field Work					
Hosting capacity study					
Network scenarios					
Hotspot modelling					
Anticipating to predicting					
Refine scenarios					
Predictive modelling					
Standards and strategies					

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Preventive solutions					

We have rated ourselves this score because we:

- **Have begun to model, future power quality hotspots on the network using validated HV and LV models populated with smart-meter data :** We completed HV power flow modelling to identify hotspots across the network. This is a recurring process incorporating new demand information and growth scenarios with key focus on the impact of decarbonisation.

  We expect to release a request for proposal this year to develop an LV visibility platform using smart meter data with use cases to inform the current state of the LV network including information on power quality, planning, design and reliability. We are in the process of finalising contractual access to Bluecurrent smart meter data to enable the LV Visibility platform to function.
- **Have refined our short-term network growth scenarios:** Our RY24 AMP includes GXP, and zone substation scenarios informed by bottom-up demand forecasting. We plan to further expand the scope of this initiative beyond our CPP commitments to include LV network forecasting. LV network forecasting is dependent on new data sources, such as the location of EV household charging and therefore the timeframe for this expanded initiative is likely to be multi-year with incremental improvements over time.
- **Predictive modelling**: We are finalising our agreement with ANSA to re-run the low voltage network analysis using their updated modelling tool and smart meter consumption data. This will include running a future constraint risk model and associated LV capex model for investment planning based on the impact of PV/EV uptake forecasts. This modelling will enable us to predict emerging constraints and invest in network upgrades ahead of power/voltage quality issues arising for consumers. We anticipate this work will be completed by November 2024.

5.3. ENGAGEMENT ON CUSTOMER CHARTER AND CONSUMER COMPENSATION ARRANGEMENTS

Customers are at the heart of our business, and we are committed to building a more customer-focused organisation that provides genuine benefits for customers.

Our customer charter outlines what we are committed to, and what we expect in return from our customers so we can meet their expectations to deliver a safe, reliable and efficient electricity supply. Our customer charter incorporates our consumer compensation arrangements, which outline how customers are compensated if we do not meet their expectations against our assigned customer experience targets.

At the time the Development Plan was set, our charter had not been reviewed for some time and public knowledge about the charter was low. We have been committed to changing that, which is why we are updating our customer charter (which incorporates our consumer compensation arrangement) and will promote it at every opportunity. Our revised customer charter will also help us continue to build a customer centric culture at Aurora Energy.

We rate ourselves 1/5 for developing our engagement with customers on our customer charter and consumer compensation arrangement in RY24

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Initial review, consultation and launch of a revised customer charter and compensation arrangement					
Increase knowledge of, and commitment to, our customer charter and compensation arrangement					
Promote and celebrate Aurora Energy's commitment to customer experience					
Conduct a further review of the customer charter and compensation arrangement to ensure it remains fit for purpose and is well understood					

We have rated ourselves this score because, while we undertook external consultation with consumers on our revised customer charter in November 2023, we delayed publishing our new Customer Commitments while we considered the feedback received and engaged further with the Commerce Commission.

At the time of publishing this ADR, we had launched our new Customer Commitments and are now turning our attention to increasing knowledge of, and our internal commitment to, the Customer Commitments through staff engagements and promotion.

By the end of RY25 we plan to have completed our RY24 initiative related to increasing knowledge of, and commitment to, our new Customer Commitments, along with our RY24 initiative related to promoting and celebrating our commitment to customer experience.

5.4. CUSTOMER OUTAGE PLANNING, MANAGEMENT AND COMMUNICATION

We are aware that no time is perfect for the power to go off, so we are committed to improving the way we plan, manage and communicate outages to minimise the impact on customers as much as we reasonably can.

To deliver on our network renewal programme, we know that the current elevated level of planned power outages will need to continue so we can carry out work to upgrade and maintain the electricity network safely.

We rate ourselves 5/5 for developing our planning, management, and communication of planned interruptions to customers

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Bundled works					
Increased use of bundled works					
Develop reliability zones					
Use reliability zones in outage planning					
Stage gate process					

Develop stage gate process				
Implement stage gate process				
Outage variations				
Adopt cancellation and deferral process				
Develop outage variation reporting framework				
Implement outage variation corrective action process				
Mitigating impact of planned interruptions				
Review current outage planning practices				
Develop and implement outage planning guidelines				
Improving the outage information to customers				
Implement new outage management system				
Provide real-time planned interruption status via the website				
Provide real-time planned interruption status via subscriber SMS				

We have rated ourselves this score because we:

- **continued to use bundled works to minimise the frequency of outages a customer may experience:** In RY24, we carried out bundled works using multiple contractors to combine multiple jobs in one outage in Dunedin (Brighton), Central Otago and Wānaka (Bendigo, Lake Hawea), and Queenstown (Arrowtown).

  We have also started combining all relevant fleet capital projects on feeders off a zone substation into a single programme of work. An Aurora Energy project manager is then assigned to each zone substation programme and the work is issued to a single contractor to enable them to plan and coordinate work across multiple assets at the same time and minimise customer disruption. The implementation of our new asset management system (Maximo) will further support work packaging across asset classes.
- **have continued to support the roll out of reliability zones in our GIS to our field service providers to use in outage planning:** Our service providers are using reliability zones in planning jobs to assess customer impact.
- **have provided real time interruption status via our website:** A new Aurora website went live in September 2023 with real-time planned and unplanned interruption status. We have also completed the initial user acceptance testing of providing real time interruption status via SMS.

5.5. ASSET DATA COLLECTION AND ASSET DATA QUALITY PRACTICES

Having accurate and reliable data about our assets to inform decision-making is a prerequisite for delivering a safe, reliable and resilient power supply. With good quality data being made available to the business, we will be able to continue improving our risk framework, our risk-based decision making, and our budgeting and forecasting activities.

We rate ourselves 5/5 for developing our asset data collection and asset data quality practices

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Asset data requirements					
Define and document key asset and network-related data requirements					
Define and document business rules to support decision making					
Asset data collection					
Automated systems for collecting data from contractors					
Improve data storage					
Implementation of an asset management software solution					
Development, and implementation of a data integration hub					
Build data management framework					
Bringing a range of policies, standards and processes in place to ensure availability and integrity					
Improve the ways in which we clean up our data					
Implement data management controls					
Implementing data audits					
Introduction of new analytical tools for internal use					

We have rated ourselves this score because we:

- **Defined and documented the key asset and network-related data that we require to support decision making:** The data requirements for Maximo, our Asset Management System, were defined in the high-level design and were implemented as part of the detailed design and implementation.
- **Continued to improve the ways in which we clean up our data:** During RY24 we put in place a data governance programme that was embraced by a wide variety of stakeholders across the organisation, which enables us to address data quality issues in a more systematic way.

5.6. ASSET MANAGEMENT PRACTICES AND PROCESSES, INCLUDING SAFETY RISK

Continuous improvement in asset management is critical for us to meet our safe network objectives, operate successfully in a changing environment, meet customers' evolving expectations, and address changes in network demand and technology. Our vision is to enable the energy future of our communities.

It is increasingly important that we continue to build on our existing asset management capability so we can enable the right investment on the right assets at the right time.

We rate ourselves 3/5 for developing our asset management practices and processes

We rate ourselves 5/5 for developing practices for identifying and reducing safety risk

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Strategy and Planning					
Strategic Asset Management Plan (SAMP)					
Fleet Strategies and Plans					
Asset Information					
Asset Failure Modes					
Define and Evaluate Risk					
Asset Health					
Asset Criticality					
Risk Evaluation					
Asset Management Decision Making					
Align decision-making with risk					
Define and monitor risk control effectiveness					
Define and document investment approval process					
Live asset risk evaluation (aspirational)					
Risk Management and Review					
Review our critical business risks					
Risk treatment plan and ownership					
Governance Reporting					

We have rated ourselves these scores because:

- Strategic asset management plan: We have started the development of our Strategic Asset Management Plan (SAMP) to more comprehensively capture our asset management strategy and objectives as outlined in our AMP. The development of the SAMP is occurring in parallel to our fleet strategies, which will enable the effectiveness and practicality of our SAMP to be tested and refined. When complete, we envisage a summarised version to be included in our AMP. For this reason, we expect to be able to complete the SAMP in RY25.
- Fleet strategies and plans / asset information: Fleet strategies and plans have been developed for all key fleets. These were used to inform our AMP24 forecasts. We will complete the remaining Fleet Strategies/Plans as well as update/maintain those completed to date, ahead of AMP25.
- Define and evaluate risk: As a part of developing the fleet strategies, we have reviewed the information requirements for a number of key fleets, including refining the associated inspection questions and standards and defining how that data will be used to inform asset health grades. We have also undertaken a desk top review of the data we have for some fleets which has enabled us to improve our associated asset health index modelling. Other enhancements to the model that we have made include more granular definitions of expected life based on type, and better integration between models to realise the associated asset renewals and the subsequent health profile improvements.

We continue to utilise public safety criticality zones to inform public safety risks, enabling us to prioritise assets by health and by the safety criticality zone they are associated with.

Significant reliability analysis has been undertaken to quantify reliability criticality for each feeder zone. Our asset management software solution, Maximo, will enable an asset to be mapped to a reliability criticality zone and thereby assign asset level criticality for reliability, as an additional consideration in prioritising renewals.

- **Asset management decision making:** The fleet strategies capture all plausible failure modes and the impact, against our corporate risk framework. While we have not progressed the use of these assessments to quantify relative risk, through the fleet strategies we are using our understanding of risk to inform required OPEX and CAPEX budgets to manage that risk.

  Where emerging failure modes have been discovered through root cause analysis (RCA), we have taken actions such as updating our inspection questions and standards; this may lead to an increase in the discovery of corrective actions, which we will need to continue to evaluate, and adjust forecasts accordingly. We will need to continue to concurrently build our failure data and mature our ability to identify trends, before we can comprehensively use failure information from RCA to inform forecasts. However, we are realising benefits of RCA through being proactive in our response. To date this has included sharing workmanship related issues with contractors, amendments to our design standards for cross-arm/pole connection spec, introduction of a new model of ABS - systemic type related failure mode and issuing of safety alerts/notices. Regarding capture of failure mode/cause data to enable trending and data interrogation, we are working on defining a cross-business unit information integration system to create and map common definitions of failure cause. This will enable the regulatory database to be updated to reflect changes in cause determination resulting from RCA. We will also consider the role of Maximo to capture root cause information against specific assets.

  Work is underway in RY25 to replace our project definition/options analysis template with a more comprehensive business case template, leveraging the 'Better Business Case' model developed by Treasury. To support the economic analysis section of our business cases, we are working with industry peers through the ENA's Future Network Forum (FNF) Workstream 2 to have an industry standardised economic analysis tool to assess network and non-network solutions.

  Consultancy support will help us to finalise the business case template and business case template user manual during RY25. The business case template and manual will capture our major project approval process.

- **Risk management and review:** Our risk treatment plans have clearly defined accountabilities and responsibilities, and continue to be monitored via standardised reporting to management and Aurora Energy's Board of Directors.

Further detail of the improvements we are making in relation to practices for identifying and reducing safety risk can be found in section 4.1 above.

5.7. COST ESTIMATION PRACTICES

Cost estimation informs Aurora Energy's business case decisions around asset management, and our budgets and forecasts inform our regulated revenue requirements and cashflow projections. This means it is important for cost estimation to be as accurate as possible.

We rate ourselves 4/5 for developing our cost estimation processes

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Enhanced unit rate estimation					
Improved management of unit rates					
Volumetric project scope breakdowns					
Major project cost breakdowns					
Establish contract unit rates					
Enhanced project cost estimation tool					
Improve project cost estimation tool					
Including a broader range of projects					
Improvements to our network opex models					
Informed 'Base' expenditure					
'Step' expenditure review					
Review our 'Trend' assumptions					
Review the vegetation forecast model					
Capture vegetation programme information in our systems					
Develop a 'Base Step Trend' or 'bottom-up' forecast model					

We have rated ourselves this score because:

- Improved management of unit rates: In RY24 we introduced an annual cost review process for the unit rates contained in our cost estimation book. These rates are informed by the PPDP average rates for volumetric work and a project review of major works to ascertain rates for items such as switchgear and power transformers. Further work for major projects as described below will further enhance the outcome of this annual review process.
- Major project cost breakdown: Following on from improvements in RY23, work has begun to better define the pricing categories in our major project tender documents. Improved categorisation will better align and inform the unit costs in our cost estimation book.
- Established contract unit rates: Our new field service agreements contain an enhanced set of unit rates for volumetric work. For example, there are more than 50 unit rates for maintenance and defect activities included in the agreements with our primary service provider.
- Improved project cost estimation tool: We have developed a major project cost estimation stage gate process and tool that was used in developing our AMP 2024 forecasts. It is estimated it will take 2 years to apply the new stage gate approach to all major projects, but the

development phase of a new process is complete subject to ongoing continuous improvement as the process is applied and learnings eventuate.

- **Including a broader range of projects in our cost estimation tool:** The cost estimation tool currently covers all zone substation work and some distribution reinforcement projects. We are at the early stages of considering how to expand the tool to cover major conductor and cable renewal projects. In some cases, the tool is sufficiently developed and therefore only requires application to the broader range of projects.
- **Improvements to our network opex models to inform 'Base' expenditure**: Base Step Trend models for all network opex categories except vegetation management are in place with routine annual reviews to adjust the Base and identify Step changes (up and down).
- **Have started to capture vegetation programme information in our systems**: Work is progressing on a longer-term development, collaborating with our internal ICT team on feasibility and targets.

5.8. QUALITY ASSURANCE PRACTICES

It is vital that all work undertaken to upgrade and maintain the electricity network meets both regulatory standards and Aurora Energy's standards, and that it is as efficient and effective as possible. Our increased work programme throughout the CPP Period means it is even more important to have robust quality assurance processes and resources in place.

We rate ourselves 5/5 for developing our quality assurance processes

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Works management capability improvements					
Develop and implement process improvements					
Continuous staff development					
Construction works quality assurance improvements					
Develop construction works review standard					
Extend scope of construction works reviews					
Incorporate quality assurance metrics into wider contractor performance metrics					
Review resourcing					
Staff training and development improvements					

We have rated ourselves this score because we:

- **Develop and implement process improvements relating to works management capabilities**: Continued to develop and implement process improvements in relation to our works management capability by meeting monthly to identify process improvements and standardise templates. The document management sites for the Dunedin and Cromwell office teams have merged to provide consistent guidance between the two.

- **Works management capability improvements:** We are continuing to train and upskill in the PRINCE2 methodology as well as extend the team’s health and safety construction knowledge by performing safety observations.
- **Extend scope of construction review works:** We have started monthly quality assurance meetings with each of our Approved Contractors. Quality assurance staff are also now getting more involved in works at site at the time the work is occurring, either through safety observations, or "real-time" quality assurance. Quality assurance staff are now also reviewing a limited range of maintenance activities across the network.

6. ENGAGING WITH CONSUMERS

Consumers are at the heart of Aurora Energy. In this section, we detail how we have engaged with the consumers on our network throughout RY24, how we are taking into account the feedback that we are receiving, and our performance against our customer charter and consumer compensation arrangement.

6.1. ENGAGING WITH CONSUMERS AND KEY STAKEHOLDERS

We rate ourselves 5/5 for how effectively we have engaged with different consumers in each of our pricing regions

What does our rating mean?

- **1 –** Did not engage with any consumers
- **2 –** Engaged with consumers via less than three channels and not in all pricing regions / did not consider feedback
- **3 –** Engaged with consumers via less than five channels and in all pricing regions / considered some feedback
- **4 –** Engaged with consumers via less than ten channels and in all pricing regions / took into account feedback
- **5 –** Engaged with a variety of consumers and stakeholders via more than ten channels and in all pricing regions / took into account feedback

We have rated ourselves this score because:

- We have an extensive communications and engagement plan that enables us to engage with many of our stakeholders and different groups of consumers across our entire network throughout the year, which we demonstrate below. We regularly review our plan to ensure it continues to meet both consumer and business needs.
- We have given effect to feedback received from consumers via various channels.
- We continued to receive positive feedback from consumers about improved communication and information that they are receiving from us. This is reflected in improving results in the 2024 customer satisfaction survey for increased awareness of Aurora Energy, an increased rating of service and performance, and an increase in trust.

Stakeholder engagement

During RY24 we engaged with a wide variety of stakeholder groups:

- **General consumers**: We engaged with general consumers across our network by:
  - Publishing our newsletter, 'Your Network, Your News', which was inserted in community newspapers in Dunedin, Wānaka, Queenstown and Central Otago in May and November 2023. This newsletter provides consumers and stakeholders with updates on major projects and programmes of work that are being undertaken across the network, as well as providing

an opportunity for us to communicate any other important messages to our community, including messaging around public safety, the changing future of electricity, pricing, sustainability and community outreach.

- Publishing a full-page advertorial in community newspapers in Dunedin (The Star), Central Otago (Central Otago News), Wānaka (Wānaka Sun) and Queenstown (Mountain Scene), in August 2023 and February 2024.
- Undertaking a public safety advertising campaign across several media channels that highlights and promotes public safety issues. Content is seasonal and changed each month.
- Hosting stalls at the 2024 A & P shows in Lake Hayes, Central Otago (Omakau) and Wānaka and at the 2024 Brighton Gala Day, where we provided an opportunity for consumers to engage directly with Aurora Energy staff.
- Hosting public forum events in October 2023 in Dunedin, Alexandra, Queenstown and Wānaka to engage on our RY23 ADR.
- Sharing copies of the material utilised in the engagements detailed above directly with stakeholders who have signed up to our email database.

– **Business community:** We engaged with the business community across our network by hosting Business After 5 events in October 2023 via the Chambers of Commerce in Dunedin, Queenstown, Wānaka and Cromwell. At these events we had a focus on the future of electricity, with a local guest speaker presenting alongside Aurora Energy. These events also provided attendees with the opportunity to engage directly with members of our executive leadership and senior management team.
– **Key stakeholder representative groups:** We presented to Grey Power Central Otago at its 2023 Annual General Meeting.
– **Major customers:** Members of our executive leadership team have engaged directly with major consumers on our network, and the Senior Relationship Manager has engaged on operational matters.
– **Councils:** Members of our executive leadership team have established trusted relationships with Queenstown Lakes District Council, Central Otago District Council and Dunedin City Council following an initial schedule of meetings approximately every six months, to share relevant updates and understand community issues regarding electricity distribution and supply. As trust has been established, regular meetings have been replaced with contact and sharing of information as required.
– **Consumers impacted by multiple planned outages:** Where consumers have been impacted by multiple planned outages due to bundled work programmes, we have directly corresponded with those consumers regarding that impact. In some instances, additional support has been provided such as generating a local hall to provide a powered facility that people can access while the power is out in their home.
– **Consumers in reliability hotspots:** This project focuses on identifying parts of the network where reliability performance is not meeting our expectations. During RY24, we engaged with consumers in those areas to communicate the work that we are doing to improve the service they are receiving. This is a long-term project where we are committed to ongoing engagement with consumers in reliability hotspot areas.

Stakeholder feedback

We provide consumers and key stakeholders with the opportunity to provide feedback on any aspect of our services, in person at any of our events or to us directly via our Customer Experience Team by phone or in writing, or via our website. For the most part, consumer feedback is specific to that individual's circumstances, and we respond to all queries that we receive. On several occasions we have received complimentary feedback from consumers in relation to the timeliness of fault response, our work to upgrade and maintain the network, and as to how helpful and friendly fault responders were.

We did not receive any feedback from consumers or stakeholders on the RY23 Annual Delivery Report that we presented in October 2023, nor did we receive any feedback in relation to our additional pricing methodology disclosures. We did not undertake any specific consultation in relation to those additional pricing methodology disclosures in RY24 because in RY22, we undertook extensive pricing consultation.

We also gather feedback from consumers via customer satisfaction surveys. These surveys have provided us with valuable feedback that we have used to inform our revised customer charter and consumer compensation arrangement. Together with other more general feedback received, the surveys also informed the outage planning guidelines that we implemented in RY23 and which have had a positive consumer impact due to work planning taking consumer needs into consideration.

Learning and insights from handling complaints

We are using learning and insights gained from complaints that we receive to improve our service where possible. Most complaints are usually related to both planned and unplanned outages that consumers experience. The learnings and insights have driven us to improve our customer service measures, including:

- The launch of a new website in September 2023 that provides automated information about planned and unplanned outages, meaning consumers get information faster than in the past when updates were manual. The new outages page includes a map and is mobile-friendly. The website redevelopment was informed by customer feedback.
- Revising our Customer and Engagement Team planning to ensure the information we provide, and community support/sponsorship, reflects what customers expect from Aurora Energy.
- We are currently developing a text notification system as consumers have told us they would like the option for this service so they can be updated via their phone about outages.

Our customer engagement team also works to ensure that other parts of the business are taking into account the feedback we are receiving and learnings we are taking from complaints. Our goal is to minimise the impact of planned outages on consumers as much as possible, particularly for consumers located in areas where reliability does not meet current expectations.

The types of complaints that we have received in the greatest numbers during RY24 are, in most cases, similar to those that we received in RY23. The highest number of complaints received were for voltage quality, although the number of complaints reduced from the prior year. For the second year running, we have seen a reduction in the number of contractor behaviour related complaints as we continue to proactively engage with consumers and communicate that feedback. We received a similar number of complaints related to the frequency of outages compared with the previous year and acknowledge the impact our five-year work programme has on consumers. We have refined the Customer Outage Guidelines, which are designed to mitigate consumer impact of planned work, by restricting planned outages over winter months in the Central Otago and Queenstown areas. The number of complaints for unsuitable timing of planned outages has reduced from the prior year.

Reprioritised or substituted capital and operational expenditure projects and programmes

> We rate ourselves 4/5 for any consultation that we have done with consumers on capital expenditure or operational expenditure projects or programmes that we propose to reprioritise or substitute.

We rated ourselves this score because, as signalled in our PPDP, information about reprioritisation was included in the May 2024 issue of Aurora Energy's community newsletter 'Your Network, Your News'. In addition to this, we added a question to our annual customer satisfaction survey to gauge the level of involvement consumers wanted to have if we needed to amend the five-year investment plan. Preliminary results showed the majority of respondents were satisfied with little involvement, so long as Aurora Energy lets the public know about any changes. We undertook extensive consumer engagement during the development of our CPP application and this feedback, together with continuing to understand our consumers' views via our extensive consumer engagement schedule, continues to inform our decision making. We had ongoing targeted conversations during RY24 with councils and consumers who made growth-related enquiries and responded to meet their requirements where appropriate.

6.2. OUR CUSTOMER CHARTER AND CONSUMER COMPENSATION ARRANGEMENTS

Our current customer charter, which incorporates our consumer compensation arrangement (Customer Charter), is a voluntary undertaking that has been in place for several years. It is an important part of our commitment to customer service, however public awareness of it is low and we feel its intent could be more clearly and simply articulated in an engaging way. We also need to make sure it focuses on those customer service attributes that consumers value and is clear about the performance targets we are committing to achieve.

We consulted with the public on a new Customer Commitments and Customer Service Incentive Payment Scheme (Customer Charter) in November 2023. Despite a month-long consultation across multiple channels there was low engagement, although the majority of respondents supported the proposal.

We chose to delay launching the new Charter while we determined the effectiveness of compensation payments with regard to how these are reflected on consumers' power bills. We engaged with the Commerce Commission and electricity retailers to get more visibility on this, to ensure consumers are getting perceptible value from the consumer compensation scheme.

In August 2024, we published our new Customer Charter.

We are committed to reporting on progress against the service levels in the new Customer Charter and are putting a robust framework in place to ensure Aurora Energy is accountable for the promises we make to consumers.

Our Customer Charter outlines the service levels we are committed to, and how consumers will be compensated if things do not go to plan. It also outlines what we need from consumers so we can meet their expectations to deliver a safe, reliable and efficient electricity supply.

During RY24, service failure payments were made on a monthly basis for the following:

- Failing to give at least ten working days' notice, via a consumer's electricity retailer, of a planned interruption ($20 credit, inclusive of GST). In RY24, we paid out $33,965 (exclusive of GST) in respect of failing to meet this service commitment.
- Failing to restore power after an unplanned interruption within set service level timeframes (if it is safe to do so) - 4 hours for urban consumers and within 6 hours for consumers in all other areas[1] ($50 credit, inclusive of GST, for residential consumers or one month's line charges for non-residential). In RY24, we paid out $310,610 (exclusive of GST) in respect of failing to meet this service commitment.
- Failing to respond to any power quality complaints within 7 working days of receipt ($50 credit, inclusive of GST). In RY24, we did not make any credit payments for not meeting this commitment because we achieved the timeframe in all instances.

The following factors contributed to the service failure payments we made in RY24:

- We continued to embed a new outage management system. The process is being streamlined and we have seen a significant improvement in our notification processes compared to RY23.
- It is not always possible to restore power within the service level timeframes for an unplanned interruption, however, we strive to do so in all instances and our service failure credit reflects the impacts on consumers where we are unable to restore within those timeframes.

[1] Urban areas are defined as Dunedin, Mosgiel, Queenstown, Wānaka, Cromwell and Alexandra. The urban areas are defined as being generally within the 50km/h speed zone boundaries. Rural and remote-rural consumers are all consumers who live outside the urban areas.

7. FEEDER PERFORMANCE

We have 256 distribution feeders across our network. In this section we identify the worst performing feeders for RY24 and outline any plans for improvement of those feeders. The worst performing feeders have been defined by the Commerce Commission as being those feeders on our network that are in the top 90th percentile or higher due to that feeder's contribution to network SAIDI or network SAIFI during RY24. While this definition of worst performing feeders is useful at a high level, it does have limitations:

- The SAIDI and SAIFI associated with planned interruptions is combined with the SAIDI and SAIFI associated with unplanned interruptions, which can mask underlying network performance issues.
- There is no consideration given to the network topology/geography where urban networks are expected to outperform remote rural networks.
- Consumer experience (number and duration of interruptions experienced) is not accurately reflected.

As a result, several feeders have been identified as worst-performing due to the high proportion of planned SAIDI and SAIFI associated with that feeder. We have not provided specific improvement plans for these feeders unless they also have poor unplanned interruption performance. We acknowledge that planned interruptions are an inconvenience to consumers, and we continue to look for opportunities to improve our practices to minimise the impact of planned interruptions (see section 5.4 above). Our planned outage work is essential to achieving a safe network and safe work practices for our contractors. We believe that the investment we are making will reduce the probability of asset failure and therefore provide long-term unplanned reliability improvements for consumers.

Feeders with higher customer numbers will accrue higher SAIDI and SAIFI values in the event of an interruption. The worst-performing feeders identified here typically have higher consumer numbers (approximately 28% of our consumers are connected to these 30 feeders). Using network SAIDI and SAIFI to gauge feeder performance means that feeders with lower ICP counts do not feature. For this reason, we have developed our own internal metric for identifying feeders with poor reliability performance. For each feeder, we have identified target unplanned SAIDI and SAIFI values based upon circuit type and configuration, circuit length, and number of consumer connections. We then identify a list of the ten worst performing feeders that form the basis of our reliability hotspots programme. We further analyse reliability performance of these feeders to identify potential targeted improvement initiatives. Finally, we engage with affected customers on each feeder to acknowledge the performance issues and outline plans for improvement.

Table 1 below includes detail for each of the worst performing feeders identified using the Commerce Commission's methodology, together with detail for each of the feeders included in our internal reliability hotpots programme.

Planned and unplanned SAIDI/SAIFI have been colour coded to indicate their contribution to the worst performing feeder status. Red cells indicate that an individual planned or unplanned value was enough to trigger the threshold value for worst performing feeder. Orange cells indicate that both planned and unplanned values combined were required to trigger the threshold value. Non-coloured cells indicate that the threshold was not met for worst performing feeder criteria set by the Commerce Commission but the feeder was identified as an underperforming against our own reliability hot spot criteria.

The remaining columns are explained below:

- Worst Performing Feeder – indicates those feeders on our network that are in the top 90th percentile or higher due to that feeder's contribution to network SAIDI or network SAIFI during RY24.
- Aurora Energy Reliability Hotspot Feeder – indicates the ten feeders that have been included in our internal reliability performance review
- Internal Annual Unplanned Outage Target – our internal unplanned outage targets set the average number of unplanned outages that each customer on a feeder may experience on an annual basis. Targets are based on expected fault rates for different circuit types – generally, long overhead feeders will experience a greater number of outages.
- Unplanned Outage RY24 Actuals – The actual performance value utilises unplanned SAIFI to estimate the number of outages per consumer connection.

Table 1: RY24 Worst Performing Feeder details

FEEDER ID	PLANNED SAIDI	UNPLANNED SAIDI	PLANNED SAIFI	UNPLANNED SAIFI	WORST-PERFORMING FEEDER	AURORA ENERGY RELIABILITY HOTSPOT FEEDER	INTERNAL AURORA ENERGY UNPLANNED OUTAGE TARGET	UNPLANNED OUTAGE RY24 ACTUALS
AB8	1.34	2.66	0.003	0.015		Yes	0.6	2.4
AT7632	2.86	2.65	0.011	0.036	Yes		8.4	5.7
AT7662	3.65	1.58	0.008	0.012	Yes		1.3	1.2
AX163	3.95	4.75	0.013	0.047	Yes		1.1	3.4
AX167	5.52	2.47	0.013	0.019	Yes		0.7	2.0
AX168	3.67	7.93	0.012	0.128	Yes	Yes	6.0	11.3
CH2006	2.47	2.65	0.006	0.037	Yes		5.6	3.7
CM821	4.72	2.37	0.016	0.042	Yes		7.7	5.5
CM831	6.89	0.01	0.018	0.000	Yes		1.2	0.0
CM832	1.76	14.96	0.011	0.205	Yes	Yes	5.4	14.0
CO6	0.00	1.01	0.000	0.047	Yes		0.3	6.8
EK480	0.60	4.71	0.002	0.068	Yes	Yes	6.1	14.8
ET3	10.15	0.21	0.029	0.002	Yes		4.1	0.3
FH5308	3.04	2.36	0.020	0.022	Yes		3.5	2.0
FK7782	5.37	2.53	0.014	0.021	Yes		3.0	1.7

FEEDER ID	PLANNED SAIDI	UNPLANNED SAIDI	PLANNED SAIFI	UNPLANNED SAIFI	WORST-PERFORMING FEEDER	AURORA ENERGY RELIABILITY HOTSPOT FEEDER	INTERNAL AURORA ENERGY UNPLANNED OUTAGE TARGET	UNPLANNED OUTAGE RY24 ACTUALS
FK7783	5.50	0.15	0.012	0.005	Yes		0.8	0.6
FK7784	8.39	4.60	0.019	0.051	Yes		7.0	3.2
GI12	4.40	0.15	0.041	0.000	Yes		1.4	0.1
HB1	1.17	1.30	0.003	0.015		Yes	0.4	2.3
LF6576	2.72	4.32	0.007	0.035	Yes	Yes	13.1	16.3
MG3	2.42	1.19	0.017	0.016	Yes		0.3	2.1
OM656	0.83	7.85	0.003	0.079	Yes	Yes	8.8	10.8
OT4	4.19	0.16	0.009	0.004	Yes		0.6	1.0
PC4	1.99	3.39	0.005	0.031	Yes	Yes	3.0	3.8
QB2423	0.61	1.79	0.003	0.027	Yes		13.2	6.9
QT5202	5.78	1.28	0.011	0.014	Yes		11.6	2.3
WK2752	8.95	5.60	0.021	0.067	Yes		10.1	4.3
WK2753	3.00	2.32	0.007	0.032	Yes	Yes	0.4	5.3
WK2755	0.90	3.12	0.006	0.034	Yes	Yes	3.9	10.8
WK2756	7.27	1.77	0.024	0.041	Yes		1.8	3.0
WK2757	1.33	1.11	0.005	0.025	Yes		1.0	2.1
WK2758	0.78	1.11	0.002	0.036	Yes		1.7	3.0

Our internal reliability metrics differ from the Commerce Commission's approach in the following aspects:

- Our reliability hotspots programme only considers unplanned SAIDI and SAIFI. Customers are generally provided sufficient notice to prepare for planned outages, and we seldom carry out a high number of planned works in one area across multiple years.
- We do not prioritise feeders with the highest SAIDI and SAIFI values. Each feeder is given its own target value, and we target feeders that show the greatest difference to target. Targets are set taking account of underground and overhead design, network sparsity and configuration. Feeders with relatively low network wide SAIDI and SAIFI impact may still be chosen as a reliability hotspot due to a higher number of outages than is expected.

Unplanned performance

For the 30 worst performing feeders identified in RY24, several have exceeded our internal unplanned targets. Where we have identified an appropriate action plan to improve feeder performance, we have provided further details alongside the feeder maps. In some cases, there were exceptional circumstances which caused a feeder to exceed its RY24 target:

- **Clyde GXP Unplanned Outages** – in January 2024, we experienced two separate unplanned outages on our subtransmission network affecting over 8,000 consumers. These outages caused increased unplanned SAIDI and SAIFI for all 16 feeders connected to the Clyde GXP.

  In response to these faults, we have conducted thorough inspections of the affected circuits to identify and resolve any defects. We replaced a faulty radio communications device which is critical to ensuring that a fault on one line does not cause the second (back-up) line to incorrectly trip. We have also engaged an independent consultant to review our protection systems to ensure that individual faults on either of our two subtransmission lines do not impact upon customers.
- **Upper Clutha Unplanned Outages** – The Upper Clutha region includes over 10,000 consumer connections across our Wānaka, Cardrona, Camp Hill, Lindis Crossing and Queensberry substations. This area was affected twice in RY24 (21st September 2023 and 8th January 2024) due to subtransmission faults.

  The Upper Clutha network is designed with sufficient capacity to enable one of two supply lines to be removed from service for planned work and the remaining line continues to supply all electricity demand in the region. However, when we take one line out of service for planned work there is a risk that a fault or an event impacts the second line and supply is lost to the region until a repair or operational action can be taken.

  As part of our investigation into both outages in RY24, we have identified improved protection and operational procedure actions that can be taken to prevent a repeat of these events. However, supply continuity remains at risk of asset failures, wildlife intrusion or third-party interference when we need to undertake planned work on one of the lines.

  Although not related to the above two outages, strong growth in the Upper Clutha increases the risk of unplanned outages during peak demand periods and we have revised our policy around planned outages on the Upper Clutha subtransmission circuits to ensure that no planned outages are scheduled during the winter period when demand is expected to be high.

  In addition, we have a non-network capacity support arrangement in place with solarZero to provide battery support during peak demand periods. We also have an upgrade project underway to provide a capacity increase of approximately 15% in the Upper Clutha by November 2025.

Where feeder performance has exceeded a target due to these subtransmission outages, we focus our action plans on ensuring that subtransmission performance issues are sufficiently addressed before considering any further action on individual feeders which may be performing to expectation.

Planned Performance

For efficiency purposes, much of our asset inspection and remediation programme is on a 5-year feeder rotation and when we enter an area we often bundle large work packages on individual feeders to help reduce the overall number of planned outages required. The 5-year rotation can mean that many customers experience multiple outages within a single year, rather than having them spread evenly across multiple years. We also have planned outage guidelines in place to help limit the inconvenience placed on consumers. In general, we do not see high annual planned SAIDI/SAIFI values as an indicator of poor reliability, but we will monitor for any feeders that experience a large number of planned outages across several years.

Worst performing feeders

Dunedin city area

Feeder CO6 – Corstorphine

Unplanned performance was below our internal target in RY24 due to a cable fault in February which resulted in multiple consumer interruptions. Given that the outage was an isolated event, we have no immediate improvement plans.

Feeder G112 – Green Island

Worst performing status is due to high planned SAIDI/SAIFI so no improvement plans are required for this feeder.

Feeder PC4 – Port Chalmers

Unplanned performance was below our internal target in RY24, which has been largely driven by vegetation-related faults. We have conducted thorough vegetation surveys in the area, and as a result, we have trimmed or felled over 300 trees on this feeder.

East Taieri area

Feeder ET3 – East Taieri

Performance dominated by a high planned SAIDI so no improvement plans required for this feeder.

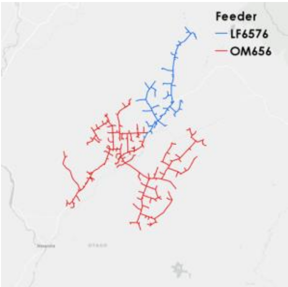
Feeder MG3 – Mosgiel

Worst performing status is due to a combination of planned and unplanned performance. Unplanned performance was below our internal target in RY24 due to an isolated event. We will continue to monitor feeder performance, but we have no immediate actions planned.

Feeder OT4 - Outram

Worst performing status was driven by a high planned SAIDI so no improvement plans are required for this feeder. Unplanned performance was slightly below our internal targets, so we will continue to monitor the feeder over time.

Omakau area



Feeder LF6576 – Lauder Flat and Feeder OM656 – Omakau

Both feeders have experienced poor unplanned performance for RY24, and the following improvement actions have been planned or completed:

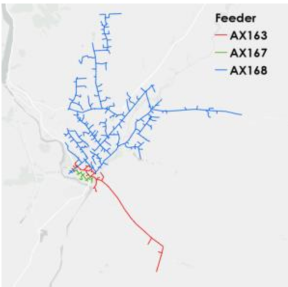
Clyde GXP Outages: In Jan 2024, our network experienced two major network outages that affected reliability performance on these feeders. We have conducted further investigations and follow-up actions to prevent future occurrences as outlined in the introductory section above.

Subtransmission Network: OM656 and LF6576 are supplied by a 33 kV overhead circuit from Alexandra. Approximately 30-40% of outages affecting these feeders are due to faults on this 33 kV circuit. We are considering long-term plans to install a second circuit that will improve area reliability.

EFD Trial: In May 2024, we commenced installation of an early fault detection system (EFD) on the 33 kV circuit that will enable us to locate potential issues and to remedy any defects before they lead to faults.

Omakau Substation: We are currently performing upgrades on the Omakau substation. Once completed, the new circuit configuration will help to reduce the impact of outages in the area. The site will also include back-up generation to provide emergency supply during outages on the 33kV subtransmission from Alexandra.

Alexandra area



Feeder AX163 – Alexandra

Unplanned performance was enough to mark this feeder among the worst performing for RY24. The major Clyde GXP outages in January were the main contributors, so we have no specific actions planned for the feeder.

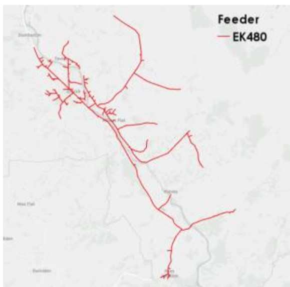
Feeder AX167 – Alexandra

Worst performing status was influenced by planned performance. Unplanned performance was also below internal targets, but this was caused by the Clyde GXP outages in January.

Feeder AX168 – Alexandra

This feeder was among our worst performing for RY24 and it has been added to our reliability hotspots programme. We are reviewing historical and ongoing performance issues to develop meaningful improvements.

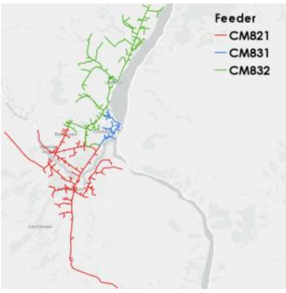
Ettrick area



Feeder EK480 – Ettrick

The major outages at Clyde GXP in Jan '24 contributed to the poor performance of this feeder. Vegetation-related faults have also been a common occurrence - we have identified problematic sites and engaged with landowners to clear any problem trees.

Cromwell area



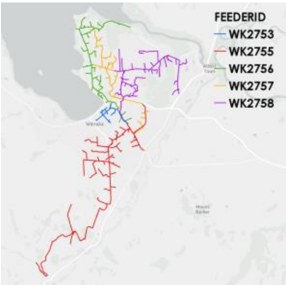
Feeders CM821 and CM831 - Cromwell

Performance dominated by a high planned SAIDI so no improvement plans required for these feeders.

Feeder CM832 – Cromwell

This feeder was among our worst performing for RY24 after experiencing frequent outages with no obvious signs of cause. After undertaking thorough follow-up investigations, we believe that we have addressed the problem, and we have already seen improvement. We have included the feeder in our reliability hotspots programme to help identify further improvement opportunities.

Wanaka area

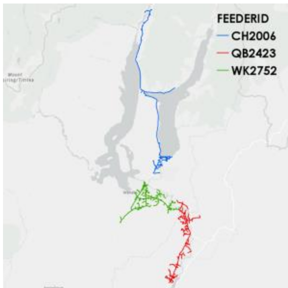


Feeders WK2753, WK2755, WK2756, WK2757 and WK2758 – Wānaka

Each of these feeders underperformed in RY24, but the primary cause was related to the major outages on our Upper Clutha circuit. We have no specific actions planned.

Feeder CH2006 – Camp Hill

Performance was driven by a combination of planned and unplanned outages. Unplanned performance was within our targets for this feeder.



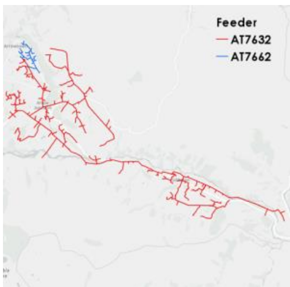
Feeder QB2423 - Queensberry

Worst performing status was driven by a combination of planned and unplanned SAIFI. Unplanned performance was within our internal targets, so no actions have been planned.

Feeder WK2752 – Wanaka

The feeder supplies over 1,500 consumer connections. As a consequence, SAIDI and SAIFI both meet the threshold for worst performing feeder even though the feeder has met our internal targets for unplanned performance. We will continue to monitor unplanned performance but no further action is planned at this stage.

Arrowtown area



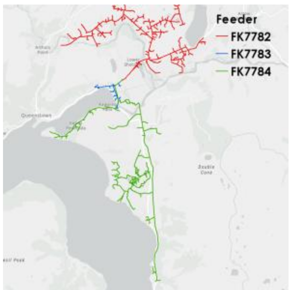
Feeder AT7632 – Arrowtown

Worst performing status was driven by a combination of planned and unplanned performance. This feeder covers a large rural area, so unplanned performance for RY24 remains within our internal targets.

Feeder AT7662 – Arrowtown

Worst performing status was driven by a combination of planned and unplanned performance. Unplanned performance was within our targets for this feeder.

Queenstown area

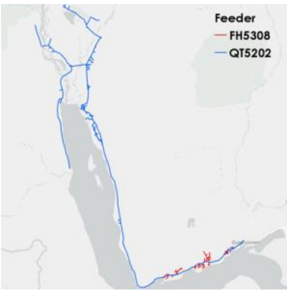


Feeders FK7782 and FK7783 – Frankton

Performance dominated by a high planned SAIDI so no improvement plans are required for these feeders.

Feeder FK7784 – Frankton

The feeder supplies over 1,500 consumer connections. As a consequence, SAIDI and SAIFI both meet the threshold for worst performing feeder even though the feeder has met our internal targets for unplanned performance.



Feeder FH5308 – Fernhill

Worst performing status was driven by a combination of planned and unplanned performance. Unplanned performance was within our targets for this feeder.

Feeder QT5202 - Queenstown

Performance dominated by a high planned SAIDI so no improvement plans are required for this feeder.

8. THE RY24 NUMBERS

8.1. EXPENDITURE

In this section, we set out actual expenditure compared to the proposed expenditure in our PPDP. The tables disclose:

- capital and operational expenditure consistent with the Information Disclosure requirements (Information disclosure category); and
- projects and programmes where the actual expenditure exceeds the proposed expenditure by 20% or more and is $1 million or more (Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)).

This information is disclosed for each pricing region and explanations for the disclosed variations to proposed expenditure are provided.

8.1.1. Dunedin pricing region

This section sets out actual expenditure compared to proposed expenditure for the Dunedin pricing region.

Table 2: Renewal Capex – Dunedin pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$37,853,207	$33,670,469	-11%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Crossarms	$3,788,133	$4,568,947	21%
Distribution conductor	$3,536,401	$7,202,032	104%
Distribution cables	$1,584,255	$2,762,670	74%
Ground mounted switchgear	$2,638,573	$3,206,939	22%
Ground mounted distribution transformers	$492,088	$1,772,873	260%

As we improve our view of asset condition, we are able to move away from age-based renewals, enabling informed decisions around investment trade-offs and optimised timing for interventions. While we navigate the change and adjust our modelling to reflect our maturing view, there will be variances to the forecast set in our PPDP. Actual asset replacement and renewal capital expenditure was lower than the PPDP forecast due to lower expenditure on subtransmission conductor and zone substations. Expenditure on these portfolios was impacted by resource constraints and cost escalation across the wider programme causing reprioritisation of our plan.

Crossarms, distribution conductor and ground mounted distribution transformer expenditure in Dunedin was undertaken at a higher cost than forecast due to escalating costs and the evolving maturity of our forecast processes. Distribution cables were undertaken as reactive works. The reactive works increased the expenditure because of the relatively short lengths involved compared to a planned intervention of larger runs of cable. Furthermore, we continue to see upward cost pressure on civil/trenching work, especially where traffic management is involved. Ground mounted switchgear expenditure was higher than forecast due to the rescheduling in RY24 of work originally planned for delivery in RY23.

Table 3: Growth and security Capex – Dunedin pricing region

GROWTH AND SECURITY CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System Growth	$3,661,504	$4,091,062	12%

System growth expenditure in the Dunedin pricing region increased from $461k in the prior year and is largely in line with the PPDP forecast for RY24.

Table 4: Other network Capex – Dunedin pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$-	$31,218	
Legislative and regulatory	$-	$0	
Other reliability, safety and environment	$-	$0	
Consumer connection	$2,546,235	$6,764,316	166%
Asset relocations	$407,398	$504,210	24%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Consumer connection - capacity event	$593,506	$4,811,587	711%

Consumer connections expenditure was higher than forecast in Dunedin due to new subdivisions being developed, as well as significant electrification projects such as the charging station for the Otago Regional Council's bus hub. We have made a reopener application to the Commerce Commission in relation to consumer connection expenditure using the capacity event mechanism available to us under our CPP.

Asset relocation expenditure was higher than expected largely due to increasing traffic management costs.

Table 5: Network Opex – Dunedin pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$5,722,540	$4,000,135	-30%
Service interruptions and emergencies	$2,411,011	$1,955,534	-19%
Vegetation	$1,488,358	$2,253,838	51%
Asset replacement and renewal	$-	$-	--
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Vegetation	$1,488,358	$2,253,838	51%

Routine and corrective maintenance and inspection expenditure was less than forecast due to a delay in the commencement of our consumer poles programme.

Service interruptions and emergencies expenditure was less than forecast due to lower levels of reactive maintenance work than expected.

Vegetation costs were higher in Dunedin as we focused on vegetation dense areas that were responsible for multiple/prior faults.

Table 6: Non-network Opex – Dunedin pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$8,887,846	$9,442,658	6%
Business support	$9,381,811	$8,452,218	-10%

Non-network operational expenditure was closely aligned to the PPDP forecast for RY24.

8.1.2. Central Otago and Wānaka pricing region

This section sets out actual expenditure compared to proposed expenditure for the Central Otago and Wānaka pricing region.

Table 7: Renewal Capex – Central Otago and Wānaka pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$12,471,260	$18,746,100	50%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			

Poles	$4,436,853	$10,814,114	144%
Crossarms	$1,308,577	$2,040,556	56%

As we improve our view of asset condition, we are able to move away from age-based renewals, enabling informed decisions around investment trade-offs and optimised timing for interventions. While we navigate the change and adjust our modelling to reflect our maturing view, there will be variances to the forecast set in our PPDP. In particular, pole and crossarm renewals are triggered by a condition-based inspection test on a 5-year cycle, and the result of that test at an individual pole site will vary from a forecast pole fleet view of the likely condition across an aggregate group of poles.

A result of this was the replacement of more poles in the Central Otago and Wanaka region than forecast, which resulted in greater expenditure. Increased crossarm expenditure also reflects the escalating costs associated with replacement of these assets.

Table 8: Growth and security Capex – Central Otago and Wānaka pricing region

GROWTH AND SECURITY CAPEX	FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System Growth	$5,125,261	$10,092,041	97%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Upper Clutha voltage support	$0	$1,911,222	
Cardrona substation transformer replacement	$0	$2,319,998	

System growth varied from the forecast mainly due to the completion of the Upper Clutha voltage support and Cardrona substation transformer replacement projects, which were forecast in the PPDP to have been delivered in RY23, but which were instead completed in RY24.

Table 9: Other network Capex – Central Otago and Wānaka pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$188,421	$1,446,858	668%
Legislative and regulatory	$0	$0	
Other reliability, safety and environment	$0	$0	
Consumer connection	$7,129,457	$8,812,459	24%
Asset relocations	$509,247	$1,715,619	237%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Consumer connection – capacity event	$1,661,816	$3,344,817	101%
Asset relocations – capacity event	$0	$1,206,372	

Quality of supply expenditure varied from the forecast, largely due to the variable number of customer enquiries and the reactionary nature of our response to remediate any issues, including our response to identified reliability hotspots. For example, we installed a recloser at Fernhill and Crown Range in RY24.

Continued population growth in Central Otago and Wānaka, together with escalating costs, meant our consumer connections expenditure was higher than forecast in the PPDP. Asset relocation expenditure was also higher than the PPDP forecast mainly due to the Wānaka NZTA state highway intersection realignment project.

Table 10: Network Opex – Central Otago and Wānaka pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$2,943,127	$3,500,698	19%
Service interruptions and emergencies	$1,446,607	$862,561	-40%
Vegetation	$1,849,834	$1,378,657	-25%
Asset replacement and renewal	$0	$0	
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Corrective maintenance	$875,709	$1,160,898	33%

Service interruptions and emergencies expenditure was less than forecast due to lower levels of reactive maintenance work than expected.

Routine and corrective maintenance and inspection expenditure was higher than forecast because we spent more to improve our asset information through improved inspection and data collection processes (preventive) and correct more asset defects (corrective).

While we carried out our planned vegetation-related inspections in RY24, the good state of vegetation clearance meant we carried out less maintenance activities than forecast, which resulted in a lower spend.

Table 11: Non-network Opex – Central Otago and Wānaka pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$4,122,719	$4,228,482	3%
Business support	$3,701,836	$3,521,039	-5%

Non-network operational expenditure was closely aligned to the PPDP forecast for RY24.

8.1.3. Queenstown region

This section sets out actual expenditure compared to proposed expenditure for the Queenstown pricing region.

Table 12: Renewal Capex – Queenstown pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$3,675,374	$9,008,522	145%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Poles	$1,516,236	$2,825,597	86%
Distribution conductor	$14,398	$1,736,299	11959%
Protection	$0	$2,070,908	

As we improve our view of asset condition, we are able to move away from age-based renewals, enabling informed decisions around investment trade-offs and optimised timing for interventions. While we navigate the change and adjust our modelling to reflect our maturing view, there will be variances to the forecast set in our PPDP.

The expenditure for poles and distribution conductor is higher than forecast primarily due to the completion of the final stage of the Glenorchy work programme. This involved rebuilding the electricity network across Dart River and through Diamond Lake. This work will benefit the community with flood resistance from stronger structures, and the new power lines will allow for increased capacity in future growth.

The protection expenditure is associated with ongoing work on the Fernhill zone substation.

Table 13: Growth and security Capex – Queenstown pricing region

GROWTH AND SECURITY CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System growth	$4,769,507	$3,955,770	-17%

Despite the high growth in the area, system growth expenditure was lower than forecast, in part due to the existence of a competing network in the region.

Table 14: Other network Capex – Queenstown pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$188,421	$538,585	186%

Legislative and regulatory	$0	$0	
Other reliability, safety and environment	$0	$0	
Consumer connection	$3,564,729	$3,657,470	3%
Asset relocations	$814,795	$1,457,143	79%

Quality of supply expenditure was more than forecast, largely due to the variable number of customer enquiries and the reactionary nature of our response to remediate reported issues. Consumer connections expenditure was consistent with the PPDP forecast despite high growth in the area. This is due in part to the existence of a competing network in the region. Asset relocations expenditure was higher than forecast due to projects initiated by Kā Huanui a Tāhuna.

Table 15: Network Opex – Queenstown pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$1,728,562	$2,185,695	26%
Service interruptions and emergencies	$964,404	$589,268	-39%
Vegetation	$588,902	$878,662	49%
Asset replacement and renewal	$0	$0	

Routine and corrective maintenance and inspection expenditure was higher than forecast because we spent more to improve our asset information though improved inspection and data collection processes (preventive) and correct more asset defects (corrective).

Service interruptions and emergencies expenditure was less than forecast due to lower levels of reactive maintenance work than expected.

Vegetation costs were higher in Queenstown as we focused on vegetation dense areas responsible for prior faults.

Table 16: Non-network Opex – Queenstown pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$2,303,168	$2,508,425	9%
Business support	$2,431,172	$2,235,743	-8%

Non-network operational expenditure was closely aligned to the PPDP forecast for RY24.

8.2. ASSET REPLACEMENT AND RENEWAL

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets during RY24 as part of our asset replacement and renewal expenditure.

The quantities in these tables do not represent all assets replaced. They instead represent:

- the number and costs of assets delivered under the asset replacement and renewal programme rather than our total expenditure programme; and
- the number and cost of assets determined using a primary-driver approach, which we explain further below.

In our PPDP, we forecasted the number of assets to be replaced and the average total cost of replacing those assets based on the primary asset being replaced. When replacing primary assets, we also replace other assets in and around the primary asset where it is either necessary or efficient to do so at that time.

This means the total average cost disclosed in the tables also reflects more than the replacement of the primary asset. It also includes the cost of associated assets replaced at the same time as the primary asset.

Box 10.2: Example Primary and Associated assets

When replacing poles under the pole programme, poles are the primary asset replaced. We may also replace other assets attached to the pole when replacing the pole because it is prudent and efficient to do so at that time. These replaced assets are associated assets. For example, if a pole-mounted transformer is replaced when replacing the pole under the pole programme then the pole is a primary asset and therefore counted as a replaced asset in the quantities identified in this section. The pole-mounted transformer is an associated asset in this example and is therefore not counted in the quantities identified in this section, but its cost of replacement is included in the primary asset (pole) replacement cost. This is consistent with how the PPDP forecast was prepared.

This information is disclosed for each pricing region and asset portfolio.

8.2.1. Dunedin pricing region

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets in the Dunedin pricing region as part of our asset replacement and renewal expenditure during RY24. Explanations are provided to assist with understanding, including why the number of assets replaced may have varied from the PPDP forecast.

Table 17: Support structure assets replaced or renewed – Dunedin pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	569	522
	Total average cost of replacing the assets	$12,670	$19,627
Crossarms	Number of assets replaced	1,349	1,173
	Total average cost of replacing the assets	$2,927	$4,392

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. As our asset risk management practices develop throughout the CPP period, we are able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning. For the Dunedin region, this resulted in fewer poles and crossarms needing to be replaced than initially forecast.

Table 18: Overhead conductor assets replaced or renewed – Dunedin pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	4.500 km	0.000 km
	Total average cost of replacing the assets	$284,217	$ -
Distribution conductor	Number of assets replaced	23.334 km	17.454 km
	Total average cost of replacing the assets	$154,884	$145,805
Low voltage conductor	Number of assets replaced	19.320 km	2.481 km
	Total average cost of replacing the assets	$131,275	$135,229

A section of the Waipori subtransmission conductor was planned for replacement in the Dunedin region in RY24 but favourable conductor condition has deferred this to RY25. The overall Waipori conductor renewal project is a 6 stage multi-year project with 5 stages left to complete over the next 6 years and the above 2nd stage may be deferred further subject to RY25 prioritisation. Delivery of distribution conductor was impacted by contractor resource constraints while we focussed on red and orange pole renewals.

We have revised our overhead system inspection standard and have commenced a new inspection programme for overhead conductor. This will enable us to have better condition information and to make a more informed decision about whether the low voltage conductor planned in the Dunedin region needs to be replaced, as opposed to making an age-based decision. For this reason, we did not replace the full amount of low voltage conductor originally planned in RY24.

Table 19: Cable assets replaced or renewed – Dunedin pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	1.867 km	0.000 km
	Total average cost of replacing the assets	$1,213,058	-
Distribution cable	Number of assets replaced	4.586 km	0.853 km
	Total average cost of replacing the assets	$433,925	$2,474,752
Low voltage cable	Number of assets replaced	1.914 km	0.045 km
	Total average cost of replacing the assets	$146,739	$3,437,457

Replacement of a section of the Kaikorai Valley subtransmission cable was the only planned subtransmission cable replacement in Dunedin in RY24. Due to pending design work, this replacement will most likely be undertaken in RY26.

We replaced small portions of distribution and low voltage cables as reactive works, which were provided for in the forecast. The reactive works distort the disclosed average cost because of the relatively short lengths involved compared to a planned intervention of larger runs of cable. Furthermore, we continue to see upward cost pressure on civil/trenching work, especially where traffic management is involved.

Table 20: Zone Substation assets replaced or renewed – Dunedin pricing region

ZONE SUBSTATION ASSET CATEGORY		PPDP FORECAST	ACTUAL
Power transformers	Number of assets replaced	0	2
	Total average cost of replacing the assets	$1,578,931	$1,373,041
Indoor switchgear	Number of assets replaced	15	15
	Total average cost of replacing the assets	$139,935	$144,449
Outdoor switchgear	Number of assets replaced	0	0
	Total average cost of replacing the assets	$144,168	-
Ancillary zone substation equipment	Number of assets replaced	0	0
	Total average cost of replacing the assets	$131,665	-
Buildings and grounds	Number of assets replaced	2	1
	Total average cost of replacing the assets	$1,008,170	$2,641,676

The forecast indoor switchgear and buildings and grounds were associated with the Smith Street and Halfway Bush zone substations. The initial scope for the Smith Street project has expanded and will now be delivered in RY26 and the Halfway Bush project will be delivered after this.

The power transformers, indoor switchgear and the building delivered were as part of the Andersons Bay zone substation project which was commissioned in October 2023, and which had not been forecast in the PPDP. The Anderson Bay site is in a residential area so required additional buildings and grounds costs to shield/absorb the transformer noise without jeopardising the cooling required for the safe operation of the transformer. The site contains a switchroom and two transformers with louvre enclosures to provide visual screening.

Table 21: Distribution switchgear assets replaced or renewed – Dunedin pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	39	29
	Total average cost of replacing the assets	$83,945	$99,528
Pole mounted fuses	Number of assets replaced	43	34

	Total average cost of replacing the assets	$5,275	$8,827
Pole mounted switches	Number of assets replaced	35	8
	Total average cost of replacing the assets	$15,182	$32,803
Reclosers and sectionalisers	Number of assets replaced	0	0
	Total average cost of replacing the assets	$85,731	-
Low voltage enclosures	Number of assets replaced	323	47
	Total average cost of replacing the assets	$5,667	$12,084

The ground mounted switchgear renewal programme was impacted by supply chain issues and escalating costs.

The replacement of the pole mounted fuses was undertaken as reactive works. The forecast in the PPDP was an allowance for such reactive works.

The pole mounted switches renewal programme was paused as we identified a systemic issue with the reliability of the new switches being deployed. We have now approved a new alternative and will continue the switch replacement programme.

Low voltage enclosure replacements have slowed as we have improved our asset health modelling to use condition-based information instead of age-based information, which has resulted in a lower number of assets needing to be replaced.

Table 22: Distribution transformers assets replaced or renewed – Dunedin pricing region

Distribution transformers asset category		PPDP Forecast	Actual
Ancillary distribution substation	Number of assets replaced	111	1
	Total average cost of replacing the assets	$4,623	$7,792
Ground mounted distribution transformers	Number of assets replaced	10	11
	Total average cost of replacing the assets	$50,748	$88,122
Pole mounted distribution transformers	Number of assets replaced	37	16
	Total average cost of replacing the assets	$32,592	$21,986

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. This has resulted in fewer surge arresters in the ancillary distribution substation fleet and pole mounted distribution transformers needing to be replaced than initially forecast.

Table 23: Secondary systems assets replaced or renewed – Dunedin pricing region

Secondary systems asset category		PPDP Forecast	Actual
Protection	Number of assets replaced	94	1

	Total average cost of replacing the assets	$20,633	$265,111
DC systems	Number of assets replaced	5	4
	Total average cost of replacing the assets	$74,086	$116,355
Remote terminal units	Number of assets replaced	1	0
	Total average cost of replacing the assets	$111,729	-

Almost all of our RY24 Dunedin protection replacement work occurred as part of major zone substation work at Andersons Bay and therefore is captured separately as part of zone substation works (see Table 20 above). For more information on our overall protection fleet status see section 4.

8.2.2. Central Otago and Wānaka pricing region

This section sets out set out the number of primary assets that we have replaced and the average cost of replacing the assets in the Central Otago and Wānaka pricing region as part of our asset replacement and renewal expenditure during RY24.

Table 24: Support structure assets replaced or renewed – Central Otago and Wānaka pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	357	628
	Total average cost of replacing the assets	$12,670	$18,630
Crossarms	Number of assets replaced	466	477
	Total average cost of replacing the assets	$2,927	$5,273

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. As our asset risk management practices develop throughout the CPP period, we are able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning. For the Central Otago and Wānaka region, this resulted in more poles and crossarms needing to be replaced than initially forecast.

Table 25: Overhead conductor assets replaced or renewed – Central Otago and Wānaka pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	0.000 km	0.100
	Total average cost of replacing the assets	$284,217	$114,337
Distribution conductor	Number of assets replaced	15.164 km	4.416
	Total average cost of replacing the assets	$154,884	$173,418
Low voltage conductor	Number of assets replaced	1.630 km	0.209

	Total average cost of replacing the assets	$131,275	$87,652

Delivery of distribution conductor was impacted by contractor resource constraints while we focussed on red and orange pole renewals. Furthermore, we have revised our overhead system inspection standard and we have commenced a new inspection programme for overhead conductor. This will enable us to have better condition information and to make a more informed decision about whether the conductor planned in the region needs to be replaced, as opposed to making an age-based decision. For this reason, we did not replace as much low voltage conductor as planned in the PPDP for RY24. The small amount of low voltage conductor work delivered was undertaken as reactive work.

Table 26: Cable assets replaced or renewed – Central Otago and Wānaka pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	0.000 km	0.000
	Total average cost of replacing the assets	$1,213,058	-
Distribution cable	Number of assets replaced	0.966 km	0.101
	Total average cost of replacing the assets	$433,925	$2,863,776
Low voltage cable	Number of assets replaced	0.000 km	0.596
	Total average cost of replacing the assets	$146,739	$172,082

We replaced small portions of distribution and low voltage cables as reactive works, which were provided for in the forecast. The reactive works distort the disclosed average cost because of the relatively short lengths involved compared to a planned intervention of larger runs of cable. Furthermore, we continue to see upward cost pressure on civil/trenching work, especially where traffic management is involved.

Table 27: Zone Substation assets replaced or renewed – Central Otago and Wānaka pricing region

ZONE SUBSTATION ASSET CATEGORY		PPDP FORECAST	ACTUAL
Power transformers	Number of assets replaced	1	0
	Total average cost of replacing the assets	$1,578,931	-
Indoor switchgear	Number of assets replaced	12	0
	Total average cost of replacing the assets	$139,935	-
Outdoor switchgear	Number of assets replaced	0	0
	Total average cost of replacing the assets	$144,168	-
Ancillary zone substation equipment	Number of assets replaced	0	3
	Total average cost of replacing the assets	$131,665	$21,857
Buildings and grounds	Number of assets replaced	0	0

	Total average cost of replacing the assets	$1,008,170	-

The forecast power transformer and indoor switchgear was associated with the Clyde/Earnscleugh zone substation. The scope of this project has since changed in light of the new Dunstan zone substation and these assets no longer need to be replaced. There was no planned replacement of ancillary zone substation equipment in RY24, however, three surge arresters were renewed as relatively minor reactive works.

Table 28: Distribution switchgear assets replaced or renewed – Central Otago and Wānaka pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	0	6
	Total average cost of replacing the assets	$83,945	$76,297
Pole mounted fuses	Number of assets replaced	0	38
	Total average cost of replacing the assets	$5,275	$6,342
Pole mounted switches	Number of assets replaced	11	3
	Total average cost of replacing the assets	$15,182	$15,949
Reclosers and sectionalisers	Number of assets replaced	2	0
	Total average cost of replacing the assets	$85,731	-
Low voltage enclosures	Number of assets replaced	2	16
	Total average cost of replacing the assets	$5,667	$7,520

The pole mounted switches renewal programme was paused as we identified a systemic issue with the reliability of the new switches being deployed. We have now approved a new alternative and will continue the switch replacement programme.

The replacement of the remaining assets in these fleets was primarily undertaken as reactive works.

Table 29: Distribution transformers assets replaced or renewed – Central Otago and Wānaka pricing region

DISTRIBUTION TRANSFORMERS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ancillary distribution substation	Number of assets replaced	87	55
	Total average cost of replacing the assets	$4,623	$5,018
Ground mounted distribution transformers	Number of assets replaced	0	8
	Total average cost of replacing the assets	$50,748	$53,011
Pole mounted distribution transformers	Number of assets replaced	22	16
	Total average cost of replacing the assets	$32,592	$14,663

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. This has resulted in fewer surge arresters in the ancillary distribution substation fleet, and fewer pole mounted distribution transformers, needing to be replaced than initially forecast and 8 ground mounted transformers needing to be replaced that were not originally forecast.

Table 30: Secondary systems assets replaced or renewed – Central Otago and Wānaka pricing region

SECONDARY SYSTEMS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Protection	Number of assets replaced	0	0
	Total average cost of replacing the assets	$20,633	-
DC systems	Number of assets replaced	4	4
	Total average cost of replacing the assets	$74,086	$10,286
Remote terminal units	Number of assets replaced	0	1
	Total average cost of replacing the assets	$111,729	$401,393

While the DC systems were largely replaced as forecast, the average cost was lower because these were not replacement of the entire systems, which reduced the cost. The remote terminal unit was the primary asset for renewal work at the Wanaka zone substation, which was not forecast in the PPDP.

8.3. QUEENSTOWN REGION

This section sets out the number of primary assets that we have replaced and the average cost of replacing the assets in the Queenstown pricing region as part of our asset replacement and renewal expenditure during RY24.

Table 31: Support structure assets replaced or renewed – Queenstown pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	122	118
	Total average cost of replacing the assets	$12,670	$26,273
Crossarms	Number of assets replaced	236	72
	Total average cost of replacing the assets	$2,927	$5,490

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. As our asset risk management practices develop throughout the CPP period, we are able to use condition-based information instead of age-based information to inform our asset health modelling and renewal planning.

For the Queenstown region, this resulted in fewer crossarms needing to be replaced than initially forecast.

Table 32: Overhead conductor assets replaced or renewed – Queenstown pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	0.000 km	0.000
	Total average cost of replacing the assets	$284,217	$ -
Distribution conductor	Number of assets replaced	0.095 km	10.741 km
	Total average cost of replacing the assets	$154,884	$142,063
Low voltage conductor	Number of assets replaced	0.424 km	0.211 km
	Total average cost of replacing the assets	$131,275	$20,827

Distribution conductor replacement and renewal was higher than forecast due to rescheduling in RY24 of carryover work from RY23.

The replacement of the low voltage conductor was undertaken as reactive works. The forecast in the PPDP was an allowance for such reactive works.

Table 33: Cable assets replaced or renewed – Queenstown pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	0.000 km	0.000
	Total average cost of replacing the assets	$1,213,058	-
Distribution cable	Number of assets replaced	0.000 km	0.082 km
	Total average cost of replacing the assets	$433,925	$2,044,533
Low voltage cable	Number of assets replaced	0.000 km	0.097 km
	Total average cost of replacing the assets	$146,739	$710,363

There was no planned replacement of specific cable assets in RY24. We did replace small portions of distribution and low voltage cables as reactive works. The reactive nature of the work distorts the disclosed average cost because of the relatively short lengths involved compared to a planned intervention of larger runs of cable. Furthermore, we continue to see upward cost pressure on civil/trenching work, especially where traffic management is involved.

Table 34: Zone Substation assets replaced or renewed – Queenstown pricing region

ZONE SUBSTATION ASSET CATEGORY		PPDP FORECAST	ACTUAL
Power transformers	Number of assets replaced	0	0
	Total average cost of replacing the assets	$1,578,931	-
Indoor switchgear	Number of assets replaced	6	0
	Total average cost of replacing the assets	$139,935	-

Outdoor switchgear	Number of assets replaced	0	1
	Total average cost of replacing the assets	$144,168	$22,016
Ancillary zone substation equipment	Number of assets replaced	0	0
	Total average cost of replacing the assets	$131,665	-
Buildings and grounds	Number of assets replaced	2	0
	Total average cost of replacing the assets	$1,008,170	-

The forecast indoor switchgear and the buildings and grounds were associated with the Queenstown substation 11kV switchgear. The project was initially delayed as part of prioritisation with growth projects and to create time to undertake concept work for later stages to ensure stage 1 site compatibility. Further delays have occurred while work is undertaken in conjunction with the Ministry of Education on the entrance driveway retainer wall to enable crane access. The outdoor switchgear was undertaken as reactive works.

Table 35: Distribution switchgear assets replaced or renewed – Queenstown pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	0	5
	Total average cost of replacing the assets	$83,945	$94,625
Pole mounted fuses	Number of assets replaced	0	7
	Total average cost of replacing the assets	$5,275	$3,811
Pole mounted switches	Number of assets replaced	0	1
	Total average cost of replacing the assets	$15,182	$28,160
Reclosers and sectionalisers	Number of assets replaced	3	0
	Total average cost of replacing the assets	$85,731	-
Low voltage enclosures	Number of assets replaced	2	9
	Total average cost of replacing the assets	$5,667	$15,170

The replacement of the assets in these fleets was primarily undertaken as reactive works. The forecasts in the PPDP were an allowance for such reactive works.

Table 36: Distribution transformers assets replaced or renewed – Queenstown pricing region

DISTRIBUTION TRANSFORMERS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ancillary distribution substation	Number of assets replaced	15	0
	Total average cost of replacing the assets	$4,623	-
Ground mounted distribution transformers	Number of assets replaced	0	3
	Total average cost of replacing the assets	$50,748	$47,742
	Number of assets replaced	1	3

Pole mounted distribution transformers	Total average cost of replacing the assets	$32,592	$34,864

Updated inspection information and our maturing network risk assessment practices have enabled us to better identify what assets require replacing. There were inherent limitations in the data available at the time we set the forecasts in our PPDP. This has resulted in no surge arrestors in the ancillary zone substation fleet needing to be renewed and 3 ground mounted and 2 pole mounted distribution transformers needing to be replaced that were not originally forecast.

Table 37: Secondary systems assets replaced or renewed – Queenstown pricing region

SECONDARY SYSTEMS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Protection	Number of assets replaced	0	0
	Total average cost of replacing the assets	$20,633	-
DC systems	Number of assets replaced	0	2
	Total average cost of replacing the assets	$74,086	$24,119
Remote terminal units	Number of assets replaced	1	0
	Total average cost of replacing the assets	$111,729	-

The two DC systems were in the Frankton zone substation, and were brought forward to coordinate with other works.

8.4. VEGETATION MANAGEMENT

Table 38 sets out the the percentage of the network that we have either inspected or felled, trimmed, removed or sprayed in RY24 as part of our three-year vegetation management plan. RY24 was the second year of that three-year plan, which is set so that 100% of the network is, across that period, inspected and maintained.

The proportion of a feeder maintained, which then contributes to our overall percentage, is determined by whether there are any outstanding maintenance tasks on that feeder as at 31 March. If no maintenance tasks were identified during an inspection of that feeder, and that inspection occurred during the regulatory year, we consider that feeder to be maintained.

This information is disclosed by pricing region.

Table 38: Vegetation management

	DUNEDIN		CENTRAL OTAGO AND WĀNAKA		QUEENSTOWN	
NATURE OF WORK	FORECAST	ACTUAL	FORECAST	ACTUAL	FORECAST	ACTUAL
Percentage of network inspected	39%	29%	43%	39%	59%	56%
Percentage of network felled, trimmed, removed or sprayed	40%	32%	44%	28%	62%	51%

8.5. SAFETY-RELATED INCIDENTS

Table 39 outlines the number of safety-related incidents that occurred on our network in RY24 in relation to network assets, maintenance, or operational activities that created a safety risk to the public, an Aurora Energy employee, or one of our contractors.

This information is disclosed by pricing region. Further detail regarding safety-related incidents is found in section0.

Table 39: Safety-related incidents

	Dunedin		Central Otago and Wānaka		Queenstown	
	RY23	RY24	RY23	RY24	RY23	RY24
Number of safety-related incidents	104	135	84	84	30	25

8.6. Reliability

Table 40 sets our reliability performance for each pricing region on our network (Dunedin, Queenstown, and Central Otago and Wānaka). The figures in this table are also disclosed in Schedule 10 of our Annual Information Disclosures for the relevant year, available at https://www.auroraenergy.co.nz/disclosures/ . These figures are our raw SAIDI and SAIFI for those pricing regions.

Table 41 sets out our reliability performance in relation to the quality compliance limits that are set out in the Aurora Energy Limited Electricity Distribution Customised Price-Quality Path Determination 2021 (CPP Determination). These are calculated:

- on a total network basis; and
- in accordance with the CPP Determination, which allows for the normalisation of unplanned SAIDI and SAIFI for major events, and the de-weighting of planned SAIDI where it meets additional notification requirements.

Table 40: Reliability – 5-year time series by pricing region

	RY24	RY23	RY22	RY21	RY20
Dunedin					
Planned SAIDI	**155.00**	117.91	134.62	87.10	70.62
Planned SAIFI	**0.68**	0.44	0.79	0.59	0.42
Unplanned SAIDI	**51.39**	65.05	51.47	59.30	91.41
Unplanned SAIFI	**0.78**	0.97	0.72	1.01	1.20
Central Otago and Wānaka					

Planned SAIDI	283.29	272.90	290.46	218.60	210.56
Planned SAIFI	0.87	0.88	0.92	0.99	3.53
Unplanned SAIDI	344.41	309.50	224.61	238.50	333.89
Unplanned SAIFI	4.52	5.18	3.33	2.72	1.16
Queenstown					
Planned SAIDI	308.59	236.58	298.17	193.70	116.52
Planned SAIFI	0.89	0.81	0.83	0.55	2.47
Unplanned SAIDI	150.20	267.98	248.36	137.60	171.77
Unplanned SAIFI	1.71	4.06	3.90	1.85	0.53

Table 41: Reliability – performance against the CPP Determination quality limits

Total network	
Planned SAIDI assessed value	121.83
Planned SAIFI assessed value	0.76
Unplanned SAIDI assessed value	95.48
Unplanned SAIFI assessed value	1.31
Planned accumulated SAIDI limit	979.80
Planned accumulated SAIFI limit	5.54
Unplanned SAIDI limit	124.94
Unplanned SAIFI limit	2.07

8.7. PLANNED INTERRUPTIONS

Table 42 sets out details on planned interruptions that we undertook during RY24.

Table 42: Planned interruptions

METRIC	RY24
Planned interruptions cancelled with more than 24 hours' notice, but less than 10 working days' notice	81
Planned interruptions cancelled without notice	110
Planned interruptions for which Aurora Energy gave additional notice	1192
Planned interruptions for which Aurora Energy did not give additional notice	195
Planned interruptions in which the interruption either started more than one hour before, or continued for more than one hour after, the period in which the interruption was notified to occur	118
Unplanned interruptions that Aurora Energy intentionally initiated to carry out work on our network that did not directly relate to a fault	92

8.8. COMPLAINTS

Table 43 through Table 45 set out details on the number of complaints received by pricing region, by complaint type and ranked in order from greatest to smallest by number of complaints and type.

Table 43: Complaints – Dunedin pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Voltage quality[1]	15	53
Damage to appliances	4	62
Contractor behaviour or service	4	29
Damage to property[2]	3	31
Planned outage – not performed as notified	3	27
Planned outage – unsuitable timing[3]	3	20
Pricing	3	13
Frequency of outages	2	16
Planned outage – not notified	2	2
Recovery of electrician fees due to a fault	1	10

1. Type of complaint with the greatest number of complaints received in RY23
2. Type of complaint with the second greatest number of complaints received in RY23
3. Type of complaint with the third greatest number of complaints received in RY23

Table 44: Complaints – Central Otago and Wānaka pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Voltage quality[1]	22	16
Planned outage – unsuitable timing	4	81
Frequency of outages[2]	4	33
Contractor behaviour or service	4	31
Damage to appliances	3	24
Planned outage - cancelled	3	20
Damage to property	3	19
Planned outage – not performed as notified	2	15
Pricing	1	36
Planned outage – not notified[3]	1	1

1. Type of complaint with the greatest number of complaints received in RY23
2. Type of complaint with the second greatest number of complaints received in RY23
3. Type of complaint with the third greatest number of complaints received in RY23

Table 45: Complaints – Queenstown pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Voltage quality	3	52
Damage to appliances	3	31
Planned outage – unsuitable timing[1]	2	15
Planned outage – not performed as notified[3]	2	2
Damage to property	1	18
Contractor behaviour or service[2]	1	9
Planned outage – not notified	1	1

1. Type of complaint with the greatest number of complaints received in RY23
2. Type of complaint with the second greatest number of complaints received in RY23
3. Type of complaint with the third greatest number of complaints received in RY23

APPENDIX A. COMPLIANCE MATRIX

The following table demonstrates how this Annual Delivery Report complies with Attachment C of the Determination.

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
Aurora must include the following in an annual delivery report:	Clause 1	
Overall progress update from board of directors		
an overview from Aurora's board of directors setting out—	Clause 1.1	
Aurora's overall progress in the following areas:	Clause 1.1.1	
for each disclosure year except disclosure year 2022, Aurora's progress in completing the capital expenditure and operational expenditure projects and programmes identified in Aurora's project and programme delivery plan under clause 2.5.4(2);	Clause 1.1.1(b)	Section 2
any actions Aurora is taking to ensure its capital expenditure and operational expenditure projects and programmes are completed as effectively and efficiently as possible;	Clause 1.1.2	Section 2
for each disclosure year except disclosure year 2022, in respect of any key capital expenditure and operational expenditure project or programme that Aurora is behind schedule in completing according to Aurora's project and programme delivery plan under clause 2.5.4(2), the reason(s) why the project or programme is behind schedule, and any actions Aurora is taking to bring the project or programme back on track; and	Clause 1.1.3	Section 2
a summary of the network safety risks Aurora has successfully reduced;	Clause 1.1.4	Section 2
Safety delivery plan reporting		
for each disclosure year except disclosure year 2022, a report on Aurora's progress against the safety delivery plan under clause 2.5.4(3) containing the following information:	Clause 1.2	

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
a visual representation of Aurora's actual reduction or change in network safety risk, grouped by asset class, as a result of delivering capital expenditure or operational expenditure projects or programmes identified in Aurora's project and programme delivery plan under clause 2.5.4(2); and	Clause 1.2.1	Section 4.1
in relation to the key network safety risks listed in the safety delivery plan,—	Clause 1.2.2	
a summary of actions Aurora has taken to reduce those risks, with reference to the principle of reducing risk to 'as low as reasonably practicable'; and	Clause 1.2.2(a)	Section 4.1
for any identified risk that Aurora has not reduced to the extent planned, a description of how, and within what timeframe, Aurora plans to reduce the risk;	Clause 1.2.2(b)	Section 4.1
Progress in developing key processes and practices – disclosure years after disclosure year 2022		
for each disclosure year except disclosure year 2022, a summary, a self-assessment rating, and reason(s) for the self-assessment rating, of Aurora's progress—		
in ensuring the information Aurora publicly discloses under clause 2.4.5A(1) enables interested persons to understand how Aurora sets prices for each Aurora pricing region; and	Clause 1.4.1	Section 5.1
against each of the following areas in Aurora's development plan under clause 2.5.4(1):	Clause 1.4.2	
developing and improving its low voltage network practices referred to in clause 2.5.4(1)(a);	Clause 1.4.2(a)	Section 5.2
engagement with consumers on Aurora's customer charter, and consumer compensation arrangement;	Clause 1.4.2(b)	Section 5.3
planning, management, and communication of planned interruptions to consumers;	Clause 1.4.2(c)	Section 5.4
asset data collection and asset data quality practices referred to in clause 2.5.4(1)(d);	Clause 1.4.2(d)	Section 5.5
asset management practices and processes referred to in clause 2.5.4(1)(e)(i) to (iii);	Clause 1.4.2(e)	Section 5.6
practices for identifying and reducing safety risks referred to in clause 2.5.4(1)(e)(iv);	Clause 1.4.2(f)	Section 5.6

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
cost estimation practices referred to in clause 2.5.4(1)(f); and	Clause 1.4.2(g)	Section 5.7
quality assurance processes referred to in clause 2.5.4(1)(g);	Clause 1.4.2(h)	Section 5.8
Spending and work done on Aurora's network		
for each disclosure year except disclosure year 2022, the key capital expenditure and operational expenditure projects and programmes that Aurora—		
has delivered on time in the most recent disclosure year;	Clause 1.5.1	Section 3
has not yet completed, but which are on schedule in accordance with Aurora's project and programme delivery plan under clause 2.5.4(2);	Clause 1.5.2	Section 3
has not completed on time, but had planned to complete in the most recent disclosure year; and	Clause 1.5.3	Section 3
has not commenced, but had planned to commence, in the most recent disclosure year;	Clause 1.5.4	Section 3
for each disclosure year except disclosure year 2022, the following information relating to capital expenditure and operational expenditure projects and programmes Aurora has undertaken in the disclosure year in each Aurora pricing region:	Clause 1.7	
Aurora's actual expenditure compared to the proposed expenditure in Aurora's project and programme delivery plan under clause 2.5.4(2), with any variance expressed as the percentage difference between proposed and actual expenditure, together with the reason(s) for the variance,	Clause 1.7.1	Section 8.1
where the actual capital expenditure or operational expenditure—	Clause 1.7.1(a)	
exceeds the expenditure proposed in Aurora's project and programme delivery plan under clause 2.5.4(2) by 20% or more; and	Clause 1.7.1(a)(i)	
is $1 million or more;	Clause 1.7.1(a)(ii)	
for each of:	Clause 1.7.1(b)	

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
consumer connection;	Clause 1.7.1(b)(i)	Section 8.1
system growth;	Clause 1.7.1(b)(ii)	Section 8.1
asset replacement and renewal;	Clause 1.7.1(b)(iii)	Section 8.1
asset relocations;	Clause 1.7.1(b)(iv)	Section 8.1
quality of supply;	Clause 1.7.1(b)(v)	Section 8.1
legislative and regulatory; and	Clause 1.7.1(b)(vi)	Section 8.1
other reliability, safety and environment;	Clause 1.7.1(b)(vii)	Section 8.1
for each of:	Clause 1.7.1(c)	
service interruptions and emergencies;	Clause 1.7.1(c)(i)	Section 8.1
vegetation management;	Clause 1.7.1(c)(ii)	Section 8.1
routine and corrective maintenance and inspection;	Clause 1.7.1(c)(iii)	Section 8.1
asset replacement and renewal;	Clause 1.7.1(c)(iv)	Section 8.1
system operations and network support; and	Clause 1.7.1(c)(v)	Section 8.1
business support;	Clause 1.7.1(c)(vi)	Section 8.1
asset replacement and renewal, including	Clause 1.7.2	
the number of assets replaced compared to the number of assets Aurora planned to replace in its project and programme delivery plan under clause 2.5.4(2) in the relevant disclosure year, with reasons for variances; and	Clause 1.7.2(a)	Section 0

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
for each asset type for which Aurora undertook asset replacement and renewal in the relevant disclosure year, the average total cost of replacing an asset of that type compared to the forecast average total cost of replacing the asset type in Aurora's project and programme delivery plan under clause 2.5.4(2);	Clause 1.7.2(b)	Section 0
compared to Aurora's documented planning for vegetation management, the percentage of the network that Aurora has, as part of its vegetation management,—	Clause 1.7.3	
inspected; and	Clause 1.7.3(a)	Section 8.4
felled, trimmed, removed, or sprayed;	Clause 1.7.3(b)	Section 8.4
Quality information – for the network and Aurora pricing regions		
for each Aurora pricing region, in a time series form for each of the most recent five disclosure years, the—	Clause 1.8	
planned SAIDI values;	Clause 1.8.1	Section 8.6
planned SAIFI values;	Clause 1.8.2	Section 8.6
unplanned SAIDI values; and	Clause 1.8.3	Section 8.6
unplanned SAIFI values;	Clause 1.8.4	Section 8.6
for each disclosure year except disclosure year 2022, in respect of each Aurora pricing region,—	Clause 1.9	
a table with the following information on any complaints from consumers about Aurora's supply of electricity distribution services in the most recent disclosure year:	Clause 1.9.1	
the type of complaint, with Aurora determining the different types of complaint by the general subject matter to which the complaints relate;	Clause 1.9.1(a)	Section 8.7
the number of each type of complaint;	Clause 1.9.1(b)	Section 8.7
the average time to resolve each type of complaint;	Clause 1.9.1(c)	Section 8.7

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
the top three types of complaints with the highest numbers of complaints and how they differ to the three types of complaints with the highest numbers of complaints from the previous disclosure year; and	Clause 1.9.1(d)	Sections 8.7 and 6.1
a description of whether, and if so how, Aurora is using the learning and insights gained from handling complaints as a feedback loop to improve the quality and service levels of in supplying electricity distribution services;	Clause 1.9.1(e)	Section 6.1
regarding the most recent disclosure year,—	Clause 1.9.2	
the number of safety-related incidents in relation to network assets, maintenance, or operational activities that created a safety risk to the public, an Aurora employee, or an Aurora contractor;	Clause 1.9.2(a)	Section 8.5
commentary on how the number of safety-related incidents compared against the previous disclosure year; and	Clause 1.9.2(b)	Section 4.2
any corrective actions taken in respect of these incidents;	Clause 1.9.2(c)	Section 4.2
for Aurora's network, in respect of the most recent disclosure year, the—	Clause 1.10	
planned SAIDI assessed value, unplanned SAIDI assessed value, planned accumulated SAIDI limit, and unplanned SAIDI limit; and	Clause 1.10.1	Section 8.6
planned SAIFI assessed value, unplanned SAIFI assessed value, planned accumulated SAIFI limit, and unplanned SAIFI limit;	Clause 1.10.2	Section 8.6
for each disclosure year except disclosure year 2022, the total number of each of the following:	Clause 1.11	
planned interruptions cancelled with less than 10 working days' notice;	Clause 1.11.1	Section 8.6
planned interruptions cancelled without notice;	Clause 1.11.2	Section 8.6
planned interruptions for which Aurora gave additional notice;	Clause 1.11.3	Section 8.6
planned interruptions for which Aurora did not give additional notice;	Clause 1.11.4	Section 8.6

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
planned interruptions in which the interruption either started more than one hour before, or continued for more than one hour after, the period in which the interruption was notified to occur; and	Clause 1.11.5	Section 8.6
unplanned interruptions that Aurora intentionally initiated to carry out work on its network that did not directly relate to a fault;	Clause 1.11.6	Section 8.6
Performance and engagement with consumers		
regarding Aurora's performance in supplying electricity distribution services to its consumers,—	Clause 1.12	
a self-assessment rating, and reason(s) for the self-assessment rating, regarding each of the following:	Clause 1.12.1	
for each disclosure year except disclosure year 2022, -	Clause 1.12.1(b)	
how effectively Aurora has engaged with different consumers in each Aurora pricing region	Clause 1.12.1(b)(i)	Section 6.1
any consultation Aurora has done with consumers on capital expenditure or operational expenditure projects or programmes, Aurora proposes to reprioritise or substitute;	Clause 1.12.1(b)(ii)	Section 6.1
summary of,—	Clause 1.12.2	
for each disclosure year,—	Clause 1.12.2(a)	
whether, and if so how, Aurora has consulted with consumers on any proposed changes to its customer charter, consumer compensation arrangement, or additional pricing methodology disclosures under clause 2.4.5A;	Clause 1.12.2(a)(i)	Section 6
any feedback from consumers on Aurora's additional pricing methodology disclosures under clause 2.4.5A; and	Clause 1.12.2(a)(ii)	Section 6.1
whether Aurora met its commitments under its customer charter and consumer compensation arrangement, and if not, the respects in which Aurora failed to do so, and the reasons for such failure; and	Clause 1.12.2(a)(iii)	Section 6.2
for each disclosure year except disclosure year 2022 –	Clause 1.12.2(b)	

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
whether, and if so how, Aurora has improved consumer awareness of its customer charter and consumer compensation arrangement;	Clause 1.12.2(b)(i)	Section 6.2
any payments Aurora has made in respect of each service level standard under Aurora's consumer compensation arrangement;	Clause 1.12.2(b)(ii)	Section 6.2
whether, and if so how, Aurora has taken account of consumers' feedback on any aspect of its supply of electricity distribution services – for example, feedback on Aurora's presentation of its summary of the key features of the most recent annual delivery report; and	Clause 1.12.2(b)(iii)	Section 6.1
the different groups of consumers Aurora has engaged with;	Clause 1.12.2(b)(iv)	Section 6.1
for each disclosure year except disclosure year 2022, the following information on Aurora's supply of electricity distribution services to its worst-performing feeders:	Clause 1.12.3	
using a map, or series of maps, of appropriate scale, the geographical location of each of Aurora's worst-performing feeders;	Clause 1.12.3(a)	Section 7
for the worst-performing feeders:	Clause 1.12.3(b)	
the planned SAIFI value(s);	Clause 1.12.3(b)(i)	Section 7
the planned SAIDI value(s);	Clause 1.12.3(b)(ii)	Section 7
the unplanned SAIFI value(s); and	Clause 1.12.3(b)(iii)	Section 7
the unplanned SAIDI value(s);	Clause 1.12.3(b)(iv)	Section 7
any plans Aurora has to improve supply of electricity distribution services on its worst-performing feeders.	Clause 1.12.3(c)	Section 7

APPENDIX B. DIRECTOR CERTIFICATION

SCHEDULE 18

Certification for Disclosures Clause 2.9.5

We, Stephen Richard Thompson and Janice Evelyn Fredric, being directors of Aurora Energy Limited, certify that, having made all reasonable enquiry, to the best of our knowledge, the information prepared for the purposes of clause 2.5.5(1) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

Stephen Richard Thompson

Janice Evelyn Fredric

29 August 2024

APPENDIX C. ASSURANCE REPORT

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Assurance Report

To the directors of Aurora Energy Limited and to the Commerce Commission on the Annual Delivery Report for the disclosure year ended 31 March 2024 as required by The Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2

Aurora Energy Limited (the company) is required to disclose certain information in an Annual Delivery Report under the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2 (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Chantelle Gernetzky, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether certain information in the Annual Delivery Report prepared by the company for the disclosure year ended 31 March 2024 (the audited Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information in the Annual Delivery Report for the 2024 disclosure year that falls within the scope of the assurance engagement is the information required by clauses 1.5, 1.7, 1.8 and 1.10 in Attachment B of the Determination.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems; and
- the audited Disclosure Information complies, in all material respects, with the Determination.

Basis for opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE (NZ) 3000 (Revised)") and the Standard on Assurance

Engagements (SAE) 3100 (Revised) Compliance Engagements ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

Key assurance matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

Key assurance matter	How our procedures addressed the key assurance matter
Expenditure The value of actual capital and operational expenditure compared to the forecast expenditure under the company's Project and Programme Delivery Plan is disclosed in section 8 of the Annual Delivery Report as required by clause 1.7.1 in Attachment B of the Determination. During the disclosure year, the company carried out a significant number of individual network system projects that are either operational (network maintenance) or capital (asset replacement or network growth) in nature. Capital expenditure in the current disclosure year totalled $80 million and operating expenditure totalled $48 million. The overall total amount of expenditure is significant relative to the company's total asset value of $830 million. Expenditure is a key assurance matter due to the significant judgement by company personnel and the auditor to assess whether the expenditure is capital or operational in nature and meets the definitions set out in the Determination.	We have obtained an understanding of the compliance requirements relevant to the Annual Delivery Report as set out in the Determination. The procedures we carried out to satisfy ourselves that the capital expenditure and operational expenditure are correctly presented in the Annual Delivery Report included: • assessing whether the company's capitalisation policy was in line with NZ IAS 16 *Property, Plant and Equipment*; • evaluating and testing the controls over the classification of expenditure; • testing a sample of capital expenditure to invoices or other supporting information to determine whether the expenditure met the capitalisation criteria in the Determination and was capitalised to the appropriate asset category; • testing a sample of operational expenditure to invoices or other supporting information to confirm the classification is appropriate; and • comparing the actual expenditure to the forecast in the published Project and Programme Delivery Plan, and assessing the reasonableness of, and support for, the variance explanations. Having completed these procedures, we have no matters to report.

Key assurance matter	How our procedures addressed the key assurance matter
Accuracy of the number and duration of electricity outages The company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the company's quality information for the network and for each of the company's pricing region, in a time series form for each of the most recent five disclosure years. If this information is inaccurate then the measures of the reliability of the network could be materially misstated. This is a key assurance matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the company's performance is assessed. There can also be significant consequences if the company breaches the reliability thresholds. As the exemption related to successive interruptions reporting no longer applies, EDBs are required to report a SAIDI and SAIFI value determined using the "multi-count approach". The "multi-count approach" requires the company to record successive interruptions as an additional SAIFI and SAIDI value if restoration of supply occurs for longer than one minute. The company has previously reported using the "muti-count approach" and therefore no changes to processes and reporting are expected.	We have obtained an understanding of the company's system to record electricity outages, and their duration. This included review of the company's definition of interruptions, planned interruptions, planned interruptions and major event days. Our procedures to assess the adequacy of the company's methods to identify and record electricity outages and their duration included: • reviewing and testing the overall control environment; • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions to supply to gain assurance that interruptions to supply were recorded. Internal and external information sources included media reports and Board minutes; • testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and the appropriateness of the categorisation of the cause of the interruption and whether it was planned or unplanned, and that the cause of the interruptions is correctly categorised; • checking the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination, including for successive interruptions using the 'multi-count approach; • obtaining explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. Having carried out these procedures and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.

Directors' responsibilities

The directors of the company are responsible in accordance with the Determination for the preparation of the Disclosure Information in the Annual Delivery Report.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), and 2.8.1(1)(c) are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information in the Annual Delivery Report has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information in the Annual Delivery Report required by the Determination have been kept by the company and, if not, the records not so kept; and
- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information in the Annual Delivery Report.

To meet these responsibilities, we planned and performed procedures in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information in the Annual Delivery Report required to be audited by the Determination.

For the forecast information reported in the audited Disclosure Information, our procedures were limited to checking that the information agreed to the company's published Project and Programme Delivery Plan prepared and certified by the directors of the company in accordance with clause 2.9.5 of the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Other information

The directors of the company are responsible for the other information. The other information comprises the information included on pages 1 to 9, 13 to 46, 65 to 66 (Section 8.5) and 68 to 78 of the Annual Delivery Report but does not include the audited Disclosure Information and our assurance report thereon.

Our opinion does not cover the other information, and we do not express any form of opinion or assurance conclusion thereon.

In connection with the reasonable assurance engagement of the audited Disclosure Information, our responsibility is to read the other information. In doing so, we consider whether the other information is materially inconsistent with the audited Disclosure Information, or our knowledge obtained in the reasonable assurance engagement, or otherwise appears to be materially misstated. If, based on our work, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use of this report

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) (PES 1) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate Professional and Ethical Standard 3 Quality Management for Firms that perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

The Auditor-General, and his employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on the Customised Price-Quality Path, the assurance engagement on the Electricity Distribution Information Disclosures and the annual audit of the company's financial statements and statement of service performance, we have no relationship with, or interests in, the company.

Chantelle Gernetzky
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
29 August 2024

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