For the disclosure year ending 31 March 2023

ANNUAL DELIVERY REPORT

Aurora ENERGY

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 94,500 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 2022 to 31 March 2023 (RY23).

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 2023. 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 second year of our CPP, which outlines the progress during RY23 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 improve the reliability of our network. Two 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.

During RY23 we experienced 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.

The steps taken to leverage existing supplier relationships and to order equipment further in advance were largely effective in mitigating upstream supply-side constraints, however the competing growth versus renewal demands impact made 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 is, however, partially offset in some network asset fleets by new favourable asset inspection information and our maturing network risk assessment practices, which is showing a reduction in the quantum of the asset renewal backlog and forecast assets requiring renewal. Improvements that we are making 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 RY23, 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)
- Pole mounted switches
- Low voltage enclosures
- Ground 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 in RY23 we cleared the backlog of 'out of compliance' red-tagged poles remaining on the network. Our focus has now shifted to orange-tagged poles, which we aim to address within 12 months of tagging. Our plan is 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 12 zone 1 (highest public safety zone classification) potheads remained on the network at the end of RY23. The overall programme to remove 375 cast iron potheads is approximately 60% complete with 149 remaining on the network. We are on track to complete this programme of work within the CPP period.

In the Dunedin area, we are strengthening the electricity supply for customers in Andersons Bay and the lower Otago Peninsula community with our renewal and upgrade to the Andersons Bay zone substation. This renewal project will be completed in RY24.

We had planned to complete the Upper Clutha voltage support and Cardrona substation upgrade projects in RY23, however, due to supply chain issues we were unable to complete these in the planned timeframe. We have received the necessary equipment and do not foresee any other issues in relation to delivery of the Upper Clutha voltage support project, which we will now complete in RY24. At the time of writing, work on the Cardrona substation upgrade had been completed.

Our CPP Period plan and associated work programme has required a significant increase in work, and we remain committed to delivering that work as efficiently and effectively as possible. With the completion of the red tag pole programme and associated spot risk renewals, our focus has turned to bundling asset remediation works together during the planning stages to minimise the number of planned outages that customers experience, and to enable work to be undertaken as efficiently as possible.

In RY23 additional unit rates were agreed with two of our field service providers relating to volumetric inspection activities. These included unit rates for ground mounted and pole mounted transformer inspection. Agreeing unit rates with our field service providers makes the administrative and billing aspects of our business more efficient.

We continue to improve our internal project management capabilities and processes so that we can deliver our projects to schedule, and to develop our new asset management software (Maximo), which will systemise our long-term asset management solution 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 RY24 we remain committed to our network safety focussed work programme which is broadly progressing to plan. However, we see a continued trend of strong demand growth in the communities we serve and a growing focus on decarbonisation through electrification. Consistent with the work delivered in RY23, our RY24 plan accelerates some urgent growth projects. In some cases, we will be seeking additional capital expenditure approval from the Commerce Commission to progress urgent customer connection and growth-related network expansion. 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, Connetics, Delta and Unison, 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 is being impacted by global supply chain pressures and escalating costs, together with resource constraints and skill shortages. In addition to these external factors, strong growth in Central Otago has driven a re-allocation of contractor resources and capital budgets to meet higher than forecast levels of customer driven growth projects in RY23. We continue to focus 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 RY23, the combination of new favourable asset inspection information in some fleets and our maturing network risk assessment practices 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 RY23
- have not completed on time, but had planned to complete in RY23.

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

In RY23 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:

- **Omakau new zone substation**: Work on the new Omakau zone substation is progressing, including the installation of a new generator to supply parts of the Omakau area if there is a prolonged outage to the area on the 33kV line from Alexandra. The zone substation is expected to be operational by the end of RY24.
- **Arrowtown 33kV ring upgrade:** Civil construction of this project started in May 2022 and is on schedule to be completed in RY24.
- **New Arrowtown substation:** A feasibility study was undertaken in RY23 as planned, and the decision as to whether to progress with purchasing land as planned will be made in RY24.
- **Smith Street to Willowbank inter-tie**: The tender has been awarded for the civil works and ducting is to be installed in RY24. The delivery of this project in RY24 is subject to us being able to coordinate the works with the ongoing upgrade of the city centre by Dunedin City Council.
- **Riverbank new transformer**: Design work has started for procurement of the transformer.

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 RY23. 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 RY23. We made significant progress with the rebuild and upgrade of the Andersons Bay substation in RY23 with scheduled completion to occur 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 RY23

In May 2022 we completed, on time, the installation of the transfer switch for the Roaring Meg generation. This now provides us with the ability to shift Roaring Meg generation to another circuit during planned and unplanned outages.

Projects and programmes we have not completed on time, but had planned to complete in RY23

We had planned to complete the Upper Clutha voltage support and Cardona substation upgrade projects in RY23, however, due to supply chain issues, delivery of the required equipment was delayed. We have now received the equipment and will undertake the planned work required to complete the Upper Clutha voltage support project after the 2023 winter. We expect this to be completed in RY24. At the time of writing, work on the Cardrona substation upgrade had been completed.

While we are making progress related to the implementation of a new asset management system, resource constraints have meant that we have not progressed as far as we had planned to by 31 March 2023. We have recently set up a dedicated team of seconded staff, including an Executive Leadership Team member, to progress the delivery of this project.

There are no key capital expenditure or operational expenditure projects or programmes that we had planned to commence that did not get underway in RY23.

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 are 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 improving our practices by which we approach asset risk, in particular asset condition and risk quantification capability. These improvement commitments were documented in our Development Plan. We report our improvement progress in relation to Asset management practices and processes, including safety risk against our Development Plan in section 5.6. Work to date has focused on refining our methodology to establish asset health information, which is to be used as a proxy for likelihood in our risk assessment.

The combination of improved and updated inspection data, and our increasing risk quantification maturity means that the relationship between asset renewals and a reduction in reported asset fleet risk is not the only influential factor. Therefore, care is required in interpreting the movement in asset fleet health and risk scores through the CPP Period.

When preparing the Safety Delivery Plan, we took the baseline, which was predominantly an age-based asset health view, from our CPP application and we adjusted the expected average age at which replacement would be required for each asset in a fleet where new data enabled us to form a more accurate assessment.

Over the last year, we have continued to focus on gathering updated condition information related to our assets. For some fleets we have been able to obtain good quality condition data which has enabled us to establish asset health at an individual asset level and therefore ascertain an asset specific forecast of remaining life. This updated condition information has enabled us to 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. For example, a support structure may have reached its age-based expected end of life, but testing may indicate that there is enough strength left in the structure to stay in compliance for another 15 years. By adding these 15 years to the life of the structure it will move from H1 to H4.

The health of some assets has also been updated because of our preliminary treatment of obsolescence. We will undertake a further review of obsolescence and there may be further adjustments with updated conclusions in our RY24 ADR.

In general, the overall effect of the improved condition information and preliminary treatment of obsolescence has been to remove assets from H1 resulting in better health profiles and lower risk scores.

An exception to the overall reduction in H1 is ground mounted switchgear. This is potentially the result of a conservative view of obsolescence and the resulting health 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 for oil filled switchgear and report updated health/condition and risk as we mature our management of this fleet.

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 summary 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 2023 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 RY23 ACTUAL H1%
Protection	48%	29.37%	51.07%
Indoor Switchgear	38%	33.43%	13.31%
Subtransmission Conductor (km)	14%	10.70%	12.84%
Crossarms	18%	17.20%	20.79%
LV Conductor (km)	17%	19.95%	11.92%
Poles	12%	9.62%	1.30%
Distribution Conductor (km)	6%	5.35%	5.68%
Power Transformers	11%	10.61%	2.94%
Outdoor Switchgear	21%	9.52%	17.78%
Ground Mounted Switchgear	9%	6.26%	9.95%
Pole Mounted Distribution Transformers	13%	14.99%	9.25%
Low Voltage Enclosures	11%	11.81%	11.10%
Subtransmission Cables (km/units*)	9%	8.79%	0.00%
Reclosers and Sectionalisers	10.53%	15.79%	11.00%
Ground Mounted Distribution Transformers	4.56%	5.79%	0.09%
Pole Mounted Switches	40.89%	42.18%	6.28%
Distribution Cables (km/units*)	2.44%	0.89%	0.35%
LV Cables (km/units*)	2.18%	3.12%	2.58%

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-related 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 be 29% by the end of RY23. However, our current data/records, which we continue to improve, show that 51% of our relays are in the H1 category. On first impression this trend may be of concern, but there are two factors influencing this result:

- Modern protection scheme solutions often require a reduced number of relays. For example, a modern 11kV feeder protection relay will displace two older relays covering both overcurrent and earth fault protection schemes. This reduction in relay count impacts the percentage scoring outlined above.
- The completeness and accuracy of our protection relay data has improved with identification of additional relays as we integrate our data into our new asset management software (Maximo).

We have made significant progress in relay replacement over the first two years of the CPP period, especially standalone feeder protection replacement projects at St Kilda (pre-CPP), Corstorphine, South City and East Taieri zone substations. We have also completed an upgrade to protection at Ettrick zone substation as part of wider renewal work at the site. Protection replacement is underway at Andersons Bay, Omakau, Roxburgh, Queenstown and Fernhill zone substations as part of major renewal work at these sites.

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. Protection replacement progress is, however, dependent on projects to renew major primary plant at zone substations.

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 but also supporting our 'as low as reasonably practicable' (ALARP) approach to safety. See chapter 8 of our 2023 AMP for a more detailed explanation of our intervention strategies for end-of-life assets.

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 are grossly 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 2023, while Figure 3 depicts this as a percentage.

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

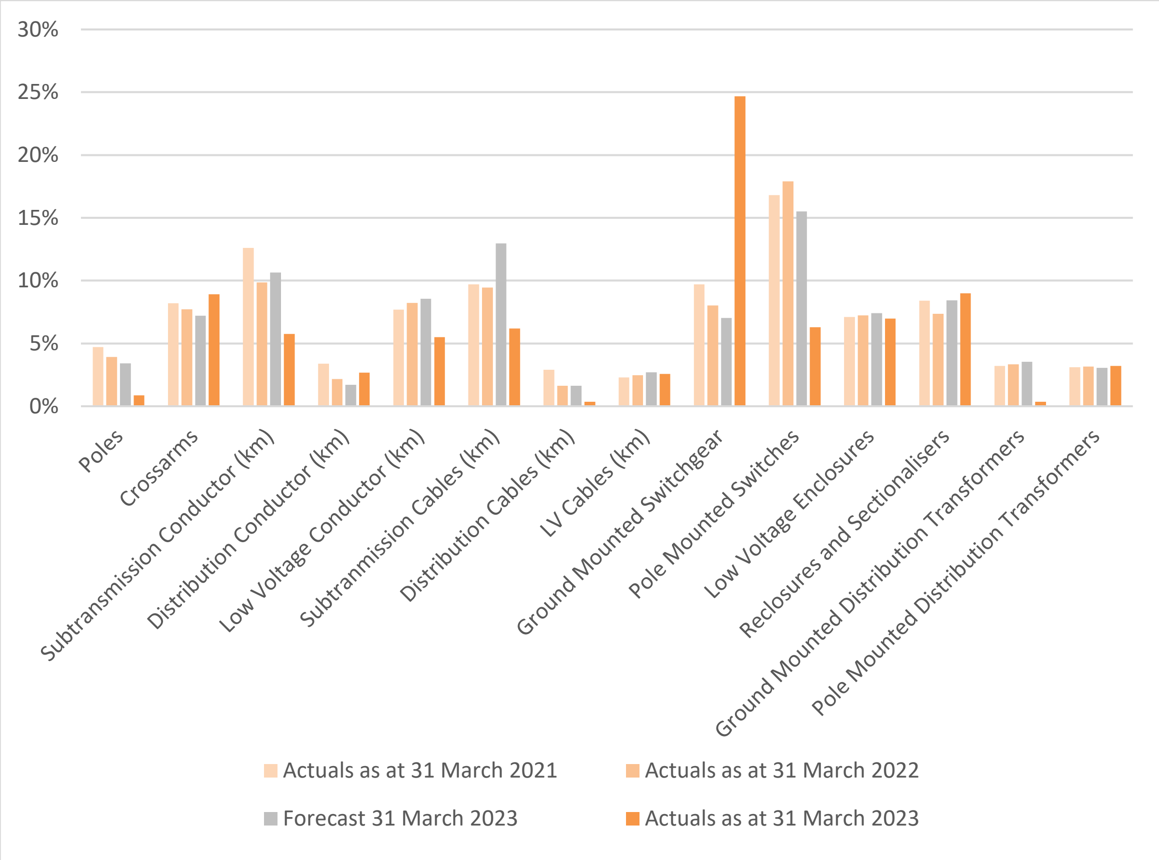
Asset risk is defined as the product of the likelihood of a failure occurring with the consequence of the failure mode. Our approach to risk quantification considers asset health as a proxy to likelihood of failure, alongside of asset criticality as a proxy to the consequence of failure. Within this 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	Forecast as at 31 March 2023	Actuals as at 31 March 2023
Poles	2487	2089	1814	461
Crossarms	7664	7209	6717	8488
Subtransmission Conductor (km)	66	51.5	55.6	29
Distribution Conductor (km)	76	49.2	39.0	60
LV Conductor (km)	72	76.8	79.8	51
Subtransmission Cables (km)	8	8.2	11.3	5
Distribution Cables (km)	32	18.5	18.5	4
LV Cables (km)	23	25.4	27.8	27
Ground Mounted Switchgear	199	164	144	340
Pole Mounted Switches	197	210	182	63
Low Voltage Enclosures	1102	1113	1139	1111
Reclosures and Sectionalisers	8	7	8	9
Ground Mounted Distribution Transformers	101	106	113	12
Pole Mounted Distribution Transformers	120	123	119	126

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



We have been unable to reduce the safety risk for five of our safety-sensitive fleets to the extent that we had planned to as at 31 March 2023:

- Crossarms
- Distribution conductor
- Ground mounted switchgear
- Reclosers and sectionalisers
- Pole mounted distribution transformers.

Several factors influenced our ability to achieve our forecast risk reduction in those five fleets, including:

- The re-allocation of contractor resources and capital budgets to meet higher than forecast levels of customer driven growth projects in RY23.
- 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 RY24.

As discussed above, the H1 classification of oil filled ground mounted switchgear is impacting the risk profile of those assets and is potentially the result of a conservative view on the health/condition of oil filled switchgear. We have made significant progress on our oil filled ring main unit major maintenance programme and we have growing confidence that the life of these assets could be extended in some cases. We are reviewing our risk quantification of this fleet as we prepare our 2024 AMP. We will set a new plan for addressing the risks associated with this fleet in that AMP to ensure that we are taking steps to reduce the risk to ALARP. The new plan will enable us to determine the revised timeframe within which we plan to reduce the risk.

We are yet to complete a full inspection of crossarms on our network and are in the process of implementing an enhanced inspection regime. It is therefore too early to update our age-based fleet view of the health of those assets. In the meantime, we will progress our crossarm renewal plan in response to the inspection results. We will monitor the rate of discovery of H1 and H2 crossarms and, if required, we will prioritise acceleration of the crossarm renewal programme to address associated safety-related risks.

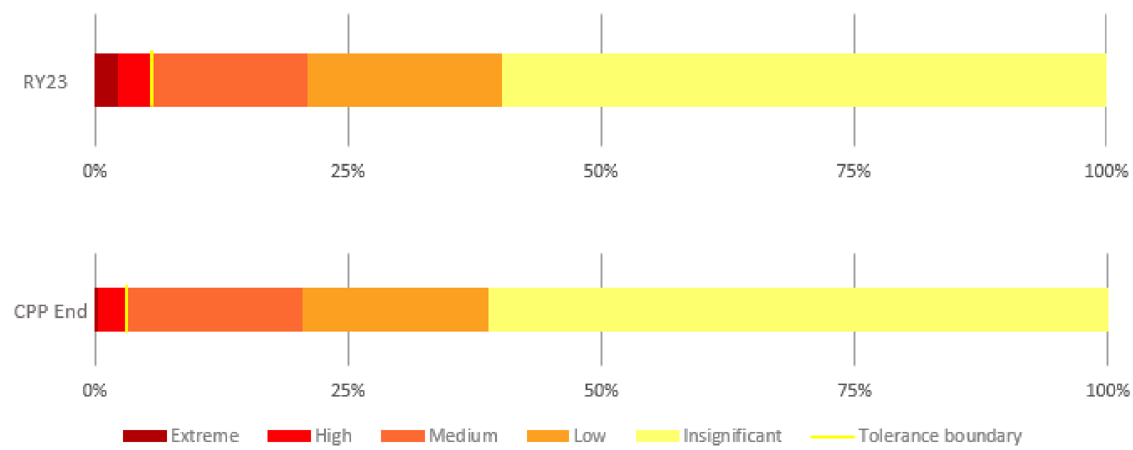
We also continue to inspect our distribution conductor fleet and will progress our replacement programme in response to the inspection results.

The updated inspection information for crossarms and distribution conductor fleet will enable us to determine revised timeframes within which we plan to reduce the risks.

The variance between actual and forecast for reclosers and sectionalisers and pole mounted distribution transformers is minor, and we still expect to achieve the expected risk forecasts for these fleets throughout the remainder of the CPP Period.

Our revised view of the total network critical safety risk change as at 31 March 2023 is illustrated in the following figure:

Figure 4: Total network asset risk profile change



4.2. SAFETY-RELATED INCIDENTS

Safety is our number one priority, and we are focused on identifying, reviewing and where necessary, taking action in relation to, safety-related incidents that occur on our network.

The number of safety-related incidents in each of our pricing regions is reported in section 8. The total number of safety-related incidents reported for RY23 is higher than for RY22. We believe the reported increase is primarily due to ongoing improvements that we are making in relation to the capture and reporting of safety-related incidents:

- In RY23 we have created a system that improves the efficiency of the data-capture and is more user-friendly at the time of reporting.
- We also refined the data attributes that we are capturing so that we are more easily able to classify events when they occur.
- A regular triage of events is being undertaken to ensure that meaningful data is captured, and follow up queries are made, in a timely manner.

The main type of safety-related incident we continue to see on our network is third-party contact with our assets. Examples of this sort of incident include contractor cable strikes, contact with overhead lines, and vehicles hitting poles or service enclosures. We were pleased to note a reduction in this type of event in RY23 when compared with RY22, which we attribute in part at least, to the proactive advertising campaigns we are undertaking across various media channels. These campaigns highlight and promote public safety messages such as staying away from fallen power lines, securing loose trampolines prior to high winds, getting in touch with Aurora Energy before undertaking work around our assets and checking the utility location system “beforeUdig”. We have recently sponsored the development of a “beforeUdig” video to be promoted nationally.

Other key contributors to safety-related incidents are:

- Asset failure;
- Contractor work practices;
- Vegetation; and
- Network operation practices.

In relation to potential asset failures, we have developed a defects app for use by our internal staff and our field service providers so that any asset defects identified on our network, including those that pose a safety-risk, can be easily reported and automatically assigned to our rapid response team for risk assessment and action where required.

We continue to proactively engage with our field service providers in relation to work practices, 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. We also:

- Host a contractor engagement forum with our field service providers twice a year at which safety-related matters are discussed, including the management of subcontractors.

- Require our field service providers to have robust systems in place to manage competency of their staff and any sub-contractors that they engage.
- Collaborate across our industry, in particular 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 the competency assurance processes that they have in place.
- Share safety alerts with all of our field service providers and approved contractors when an incident or near-miss occurs so that all contractors can share in the learnings.

If we are not satisfied that our field service providers or approved contractors have processes in place to ensure safety while working on the network, we take action to suspend that company's approval to work in or around our network assets until such time as they can demonstrate to us that action has been taken to address the issues that led to the suspension.

To manage vegetation related incidents, we are inspecting our network on a three-year cycle, with 12-month inspections for critical areas such as fire prone zones and those with significant vegetation-related issues. While we are limited in our ability to manage vegetation risks by the current limits within the Electricity (Hazards from Trees) Regulations 2003, we require our field service provider to aim for greater clearances with tree owner approval. We have also developed a tree safety notice for use when we identify vegetation risks that are not covered by the existing regulations, so that we can collaborate with tree owners to identify appropriate ways of addressing the risk.

In response to network switching-related safety incidents we scheduled a safety reset day in December 2022 with our relevant Operations Team staff, which focussed on identifying issues and enhanced training to ensure that our outage planning and execution practices meet expectations. This was well received by our staff, and well supported by our field service providers.

We are currently planning to engage specifically with the councils in our region on traffic management practices in an attempt to address the number of vehicle impact-related events we are experiencing.

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 the 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 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 Lakes) 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 on 31 March 2023. 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 RY23 in particular, we have:

- **Published a cost of supply model:** We continue to publish our cost of supply model, which provides additional transparency for customers about how we allocate costs to pricing areas and customer load groups.
- **Provided worked examples for customers:** These help customers understand pricing better as they outline charges for a 'standard' customer in each pricing area.
- **Rebalanced and simplified control tariffs:** 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.
- **Removed seasonal tariffs:** The distinction between summer and winter usage has been removed from the pricing schedules. The removal of seasonal tariffs reduces the degree of seasonal bill shock some customers experience during winter as well as simplifying the pricing structure.
- **Improved information on our website:** Information on our website has been refreshed so that it further explains electricity pricing and provides answers to commonly asked questions.
- **Continued to engage with key stakeholders:** We take the opportunity to attend key stakeholder forums, such as the Greypower Dunedin Annual General Meeting, which we attended in May 2022, 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 5/5 for developing our low voltage network practices during RY23.

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					

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Anticipating to predicting					
Refine scenarios					
Predictive modelling					
Standards and strategies					
Preventive solutions					

We have rated ourselves this score because we:

- **Developed a distributed generation congestion policy based on a hosting capacity study:** A hosting capacity study was conducted by ANSA Consulting to understand the available capacity on our low voltage networks to connect new distributed generation (solar/photovoltaic) without causing network overload or breaches of regulated power quality standards. We have undertaken analysis of the results and incorporated this into our network congestion policy. The next stage is to improve analysis through the use of smart meter data and make further refinements to our congestion policy and supporting information to report areas of emerging network congestion.

  ANSA also undertook analysis of how the charging of electric vehicles will impact power flows and constraints on our low voltage network, thereby enabling us to predict areas where power quality may be at risk in the future. We are participating in an Ara Ake initiative to support ANSA to further develop their software incorporating a dashboard to enable forecasting scenarios to be created and associated reports to be generated.
- **Have created a set of network growth scenarios:** as outlined above, these scenarios can be incorporated into our network modelling to assess the potential impacts to power quality. This is an ongoing continuous improvement project with a key focus on the impact of decarbonisation through electrification.
- **Have begun to roll out distribution transformer monitoring (DTM) units:** 40 units have been rolled out across distribution transformers in strategic parts of our network to provide a baseline capture of performance and trend analysis as well as inform network scenarios.

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.

Our charter has not been reviewed for some time and public knowledge about the charter is low. We are 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 3/5 for developing our engagement with customers on our customer charter and consumer compensation arrangement in RY23

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 we have conducted a thorough internal review of the existing customer charter and internal consultation on the new charter. This included undertaking an assessment of our existing customer charter commitments and reviewing the effectiveness of the existing compensation arrangement. We have done this by holding internal workshops which all staff have had the opportunity to participate in as well as specific workshops with our executive leadership team and relevant staff members looking at the existing customer charter and looking at what parts are working and what parts were not working, with a view to making it simple and actionable.

We have also surveyed other electricity distribution businesses about their customer charters and undertook a desktop review of the customer charters we were able to locate on their websites.

External consultation with consumers has been delayed and will commence in RY24. The reviewed Customer Charter is planned to be launched in December 2023.

Our external consultation with consumers has been delayed due to resource constraints meaning that we are yet to launch a revised customer charter and consumer compensation arrangement as we had planned.

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:

- **implemented the stage gate process that we developed in RY22:** This process was developed in RY22 to identify potential customer impacts of planned outages earlier and mitigate those impacts more effectively. This stage gate process was implemented over the course of RY23 and enables us to identify the potential customer of planned outages earlier in the scheduling process so that we can plan and mitigate customer impacts more effectively.
- **developed and implemented an outage variation corrective action process:** This process has been developed and is used with corrective actions or improvements recorded. This enables us to identify any corrective actions and improvement opportunities when a planned interruption runs significantly over or under the scheduled time, is cancelled or deferred following customer notification, or if the notification list was identified as inaccurate. Over time, corrective actions and improvement opportunities identified through this process should reduce customer disruption from planned outages not proceeding as planned.
- **developed and implemented outage planning guidelines:** These set out our expectations when it comes to minimising the customer impact of planned outages on customers. These guidelines were implemented in November 2022. The guidelines must be considered by all those involved

in the planning and management of planned interruptions. Weekly meetings are held to support and manage performance against expectations.

- **implemented a new outage management system (OMS):** In July 2022 we implemented a new OMS within our advanced distribution management system to enhance our outage planning and the handling of fault response. This has enabled us to access real-time updates on planned interruptions as they occur and provides a single data source to update our customer channels on the status of active interruptions in real time.
- **continued to use bundled works to minimise the frequency of outages a customer may experience:** This is considered at many points within the works planning process. This year, we undertook significant bundled works in Ettrick, Henley, Halfway Bush, Cromwell, Arrowtown and Alexandra to minimise the impact to customers in those areas.
- **have rolled out our reliability zones in our GIS to our field service providers to use in outage planning:** the zones help inform outage applications by locating all customers in the planning outage area and feeding this into the process.

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 key asset and network-related data requirements:** many of the key asset and network-related data requirements that will be used both as asset attributes for use in our asset management software solution as well as in the internal documentation that is shared with our field service providers have been defined and documented. These data attributes include asset type, nameplate information, capacity, condition metrics and locational data, including public safety zones etc.
- **Put in place a range of policies, standards and processes to ensure availability and integrity of data**: A standard which governs surveying works of our assets has been developed and implemented. This ensures that contractors are providing us the information we need in the format we require. This is leading to an improvement in the accuracy of our asset location data. The associated processes have also led to an increase in the integrity of our data, through the increased internal review of GPS (DWG) files received from our contractors. Any anomalies are captured by automated exception reporting and reviewed by our quality assurance staff to ensure accurate data is captured. We have also worked to reduce the inconsistency between the historical network plans and our GIS with the goal of ensuring that GIS can become one single source of truth regarding the geographical location of our assets.
- **Improving the ways in which we clean up our data, including implementing data audits:** During RY23 we have made improvements to the way that we clean our data. We have done this by:
  - harnessing the functionality of PowerBI to perform exception reporting so that we can identify any data entry errors that may have been made while capturing data from the field, and monitoring to ensure corrections are made quickly;
  - implemented feature manipulation software (FME), which enables us to compare location-related data to ensure accuracy; and
  - planning the integration of asset data from the field to our asset management software solution to reduce the amount of manual data entry.

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 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 4/5 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 outlined in our AMP. The development of the SAMP is occurring in parallel with our fleet strategies, which will enable the effectiveness/practicality of our SAMP to be tested and refined as we progress through the fleet strategies. When complete, we envisage a summarised version to be included in our AMP.
- Fleet strategies and plans / asset information: We started to develop fleet strategies and plans, including training for our lifecycle engineers and specified asset attributes and collection methods. We are planning to complete a first draft of the strategies and plans for key fleets during RY24, enabling the 2024 AMP, RY25 plan and our 10-year capital and operational expenditure forecasts to reflect our most up to date asset information and strategic approach.
- Failure modes: We have completed a first draft of documented failure modes, including effects and consequence analysis for all asset fleets. The next step is to enhance and refine the draft as we incorporate failure mode analysis into our fleet strategies. Failure mode identification and capture will continue as part of our ongoing fault-related root cause analysis.
- Define and evaluate risk: Work has begun on the development of asset health formulae linked to asset inspection/condition assessments. We utilise public safety criticality zones to inform public safety risks and this has allowed us to develop high level risk treatment plans for those

fleets that are the highest safety risk. 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.

- **Asset management decision making:** We have introduced enhanced root cause classification of fault related asset failures, enabling better tracking of risk control effectiveness. Further development of our asset management processes is required to ensure that the results of root cause analysis is integrated into our fleet strategies and our risk treatment plans.

  We continue to improve our problem definition and business case templates and supporting cost benefit analysis tool/s. In the short term, the use of these templates and tools will be integrated into our project cost estimation process, which is discussed in section 5.7 below. In the medium term we will document our broader project approval and management processes from inception through to commissioning.

  Risk quantification (as described above) for each business case option will be a key component of our asset management decision making.

- **Risk management and review:** We have completed a review of our critical business risks. Our risk treatment plans have clearly defined accountabilities and responsibilities, and we are monitoring 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 5/5 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					

KEY ACTIVITIES / MILESTONES	RY22	RY23	RY24	RY25	RY26
Enhanced unit rate estimation					
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: Unit rates in this context are referred to as cost estimation rates to enable improved project and programme budgets and forecasts. We have started to improve the management of cost estimation rates by finalising the scope for a comprehensive system and processes to manage these, with a particular focus on major project cost estimation. This initiative is on track for completion in RY24.
- Volumetric project scope breakdowns: We have put in place processes and systems that now enable us to develop reports to monitor costs by the primary asset type, which enables us to undertake an annual review of cost estimation rates for volumetric fleet asset renewals.
- Major cost breakdowns: We have revised our major project scopes and implemented tender documentation to provide the necessary breakdown detail, which will be used to inform annual reviews of our cost estimation rate components.
- Establish contract unit rates: We have commenced the review of our field service agreements, which includes the development of unit rates for volumetric work. In RY23 additional unit rates were agreed with two of our field service providers in relation to volumetric inspection activities (ground mounted and pole mounted transformer inspections).
- Improved project cost estimation tool: We have established a project team and development of a cost estimation tool is underway. A framework for collecting data on costs and quantities was established, and we can now track asset cost components in our finance system. This will allow us to monitor and adjust project cost estimation rates annually, which will result in more precise delivery budgets and forecasting.
- Informed 'base' expenditure: We undertook an initial high-level review of our operating expenditure forecasts as a part of developing our 2023 AMP, and are on track to undertake a more detailed review in RY24.
- 'Step' expenditure review: We reviewed our forecast 'step' changes in operating expenditure as a part of developing our 2023 AMP. The development of our fleet strategies will provide a key input to the identification of step changes in preventive and corrective maintenance for our 2024 AMP.
- 'Trend' assumption review: We are monitoring trends in our network operational expenditure and reviewed our current 'trend' assumptions as a part of developing our 2023 AMP. We will undertake further analysis as and when required in the future to ensure that our trend assumptions remain current.

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, so 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 making further project workflow process improvements, including developing additional checklists within our project management system, developing standardised templates for different aspects of project management, and focussing on aligning processes used by project managers across our two office locations.
- **Continuous staff development in relation to works management capabilities**: Continued to focus on developing our staff's work management capabilities by continuing to train new staff in the PRINCE2 methodology and providing refresher training for staff when required.
- **Works review standard:** We developed and implemented an internal construction works review standard which supports our quality assurance staff to review work performed in the field to ensure that the work delivered meets the design requirements. This has resulted in more consistent field work and feedback by our quality assurance staff.
- **Extend scope of construction works reviews**: We have considered the scope of our construction works reviews and have identified the maintenance activities performed on the network that would benefit from greater quality assurance.
- **Quality assurance metrics**: We have developed quality assurance metrics which enables us to compare the performance of each field service provider in relation to the quality of the work that they are delivering.

- **Staff training and improvements relating to construction works quality assurance**: Quality assurance staff were trained in performing on-site safety observations in RY23. We will continue to invest these areas, particularly as we extend the scope of our construction works reviews to ensure that our staff have the skillsets and capabilities required.

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 RY23, 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 for the following reasons:

- We have an extensive stakeholder 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 have given effect to feedback received from consumers via various channels.
- We have received positive feedback from consumers about improved communication and information that they are receiving from us.

Stakeholder engagement

During RY23 we engaged with many different 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, Wanaka, Queenstown and Central Otago in May 2022 and November 2022. 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 or in relation to pricing changes.

  - Publishing a full-page advertorial in community newspapers in Dunedin (The Star), Central Otago (Central Otago News), Wanaka (Wanaka Sun) and Queenstown (Mountain Scene), in January 2023.
  - Undertaking a public safety advertising campaign across several media channels that highlights and promotes public safety issues. Content is changed each month and is seasonal.
  - Hosting stalls at the 2023 A & P shows in Lake Hayes, Omakau, Roxburgh and Wanaka and at the 2023 Brighton gala day, where we displayed information about the progress that we are making in upgrading and investing in the network and provided an opportunity for consumers to engage directly with Aurora Energy staff.
  - Hosting public forum events in May 2022 in Dunedin, Alexandra, Queenstown and Wanaka to engage on our CPP Plans.
  - Hosting public forum events in October 2022 in Dunedin, Alexandra, Queenstown and Wanaka to engage on our RY22 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 via the Chambers of Commerce in Dunedin, Queenstown and Cromwell. We also presented to U3A in Wanaka in March 2023. At these events we shared information on Aurora Energy and the work we are undertaking in the specific areas. 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 Greypower Dunedin at its 2022 Annual General Meeting .
- **Major customers:** Members of our executive leadership team have engaged directly with major consumers on our network.
- **Councils:** Members of our executive leadership team meet with Queenstown Lakes District Council, Central Otago District Council and Dunedin City Council approximately every six months to share relevant updates and understand community issues regarding electricity distribution and supply.
- **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.
- **Consumers in reliability hotspots:** We have established a new reliability hotspot project, which focuses on identifying those parts of the network where reliability performance is not meeting our expectations. We are engaging with consumers in those areas to communicate the work that we are doing to improve the service they are receiving. Such engagement has included hosting community meetings in Omakau, Pisa Moorings and Arrowtown, and where possible we use relationships that we have built within the community (ie community boards or a community leader) to help to effectively communicate with the community.

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. 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 and as to how helpful and friendly fault responders were.

We did not receive any feedback from consumers or stakeholders on the RY22 Annual Delivery Report that we presented in October 2022, 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 RY23 because in RY22, 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.

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:

- Implementing an interactive voice response in our call centre, which is an automated phone system tool that answers incoming customer calls and offers options or next steps via a menu.
- Implementing our customer outage guidelines.
- Starting a project to redevelop our website, which we aim to launch in RY24. The website content will be presented in a more consumer-friendly format and in particular will feature a new view of current and upcoming outages on the network.

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 RY23 are in most cases different to those that we received in RY22. We have seen a reduction in the number of contract behaviour related complaints as we continue to proactively engage with consumers and communicate that feedback. We have also seen a reduction in the number of complaints related to the frequency of outages, which reflects the emphasis that we are placing on engaging early with affected consumers and communities as we continue to deliver our elevated work plan, which is resulting in a greater number of planned interruptions for some customers (see section 5.4). We continue to develop our low voltage practices, which will in time improve voltage quality for consumers (see section 5.2).

Reprioritised or substituted capital and operational expenditure projects and programmes

> We rate ourselves 3/5 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 2023 issue of community newsletter 'Your Network, Your News'. 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. In RY23, we engaged with key decision makers within the councils across our region, particularly the Queenstown Lakes District Council. These conversations in particular related to growth on the network. We also had specific discussions with a number of 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 customers value and is clear about the performance targets we are committing to achieve. We will call the new document our "Customer Commitments".

As we roll out the "Customer Commitments", we will take action to improve awareness of that document. In the meantime, we have ensured that the Customer Charter is more easily accessible on our website by including a link to it in the "Quick Links" section of our homepage.

We have not yet commenced consultation with consumers on proposed changes to the Customer Charter. We have developed an updated suite of proposed performance metrics and a plan for how we will undertake a robust consultation process, as detailed in section 5.3 above. We have largely met the intent of our Customer Charter commitments. We are aware our Customer Charter is not prescriptive or measurable to the degree we would like it to be and intend for these aspects to be improved with our new Customer Commitments document.

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.

Service failure payments are 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 (inclusive of GST) credit). In RY23, we paid out $98,467 (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 (inclusive of GST) credit for residential consumers or one month's line charges for non-residential). In RY23, we paid out $409,008 (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). In RY23, 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 RY23:

- We have over the course of the last year, implemented a new outage management system, which, together with previous planning improvements that we had made, has enabled us to streamline our notification process. These are still relatively new enhancements, which we are continuing to bed in.
- 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 customers are all customers who live outside the urban areas.

7. FEEDER PERFORMANCE

We have 248 distribution feeders across our network. In this section we identify the worst-performing feeders for RY23 and outline any plans for improvement for those feeders. The worst-performing feeders have been defined by the Commerce Commission as being those feeders on our network that are in the 90th percentile or higher due to that feeder's contribution to network SAIFI or network SAIDI during RY23.

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 outages, 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.

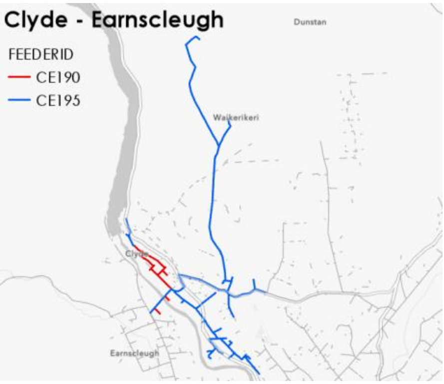
As a result, several feeders have been identified as worst-preforming due to the high proportion of planned SAIDI and SAIFI associated with that feeder. We have not provided specific improvement plans for these feeders unless they also have poor unplanned interruption performance. We acknowledge that planned interruptions are an inconvenience to consumers, and we believe that the investment we are making will provide long-term reliability improvements. We also remain focussed on improving our practices to minimise the impact of planned interruptions (see section 5.4 above).

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 30% of our consumers are connected to these 35 feeders). Using network SAIDI and SAIFI to gauge feeder performance means that feeders with lower ICP counts do not feature.

Using industry average unplanned interruption rates, we have developed our own internal metrics to gauge unplanned performance for our distribution feeders. These rates consider the overall length of a feeder and distinguish between overhead and underground circuits. Long overhead circuits will have a different performance expectation to short feeders with mainly underground sections. These internal metrics used to identify feeders that require specific improvement. For many of the worst-performing feeders listed here, their unplanned performance remains within our performance expectations. In these cases, we have provided no specific action plans.

In RY23, we established an internal reliability hotspot initiative to identify areas of our network that were experiencing poor reliability performance. For ten identified feeders, we undertook closer analysis of the unplanned interruptions on that feeder and then developed plans to address any identified issues. We have also coordinated with our Customer Engagement team to communicate our plans with affected consumers. Several of the feeders that we have identified in this initiative appear on this worst-performing list. In these cases, we have outlined the key actions that have been identified to improve performance.

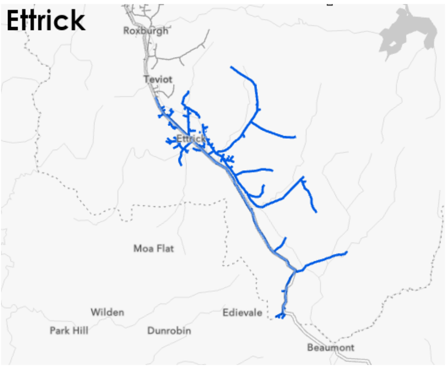
Clyde / Earnscleugh area



Feeder CE190 – Clyde / Earnscleugh		
Planned SAIDI	3.66	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – The feeder underperformed against our expectation for this year. The circuit experienced unknown outages early in the year, but additional inspections identified vegetation as the root cause. The circuit has experienced no outages since, but we will continue to monitor its performance.
Planned SAIFI	0.009	
Unplanned SAIDI	1.53	
Unplanned SAIFI	0.021	

Feeder CE195 – Clyde / Earnscleugh		
Planned SAIDI	4.57	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – Unplanned performance is within our expectations for the feeder.
Planned SAIFI	0.013	
Unplanned SAIDI	1.18	
Unplanned SAIFI	0.020	

Ettrick area

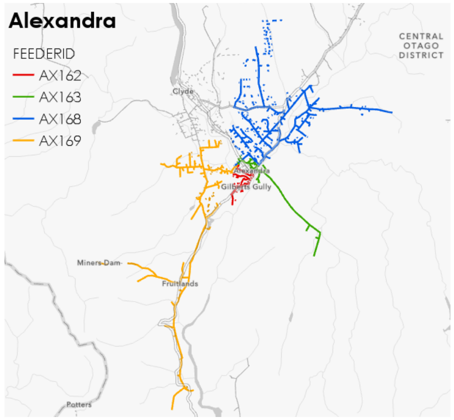


Feeder CB480 – Ettrick		
Planned SAIDI	1.51	– This feeder has previously been identified as having poor reliability performance in RY22. – We completed a significant package of works in March 2023. Performance for RY23 has shown improvement and is within our performance expectations for a large rural area.
Planned SAIFI	0.006	
Unplanned SAIDI	3.95	
Unplanned SAIFI	0.027	

Alexandra area

We have experienced issues with the earth fault sensitivity of our protection systems in the area due to the highly resistive soils. As a result, distribution circuits are prone to trip during planned switching operations.

We have reviewed our switching practices as a short-term solution and implemented measures to ensure that these faults do not reoccur. We have initiated an investigation with an external consultant to advise on a longer-term solution.



Feeder AX162 - Alexandra

Planned SAIDI	5.70
Planned SAIFI	0.016
Unplanned SAIDI	0.70
Unplanned SAIFI	0.011

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance is within our expectations for the feeder.

Feeder AX163 - Alexandra

Planned SAIDI	4.62
Planned SAIFI	0.012
Unplanned SAIDI	1.60
Unplanned SAIFI	0.044

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- For unplanned outages, this feeder underperformed against our expectations for this year. The poor performance was driven by a one-off event in October 2022. We have no immediate actions for this feeder, but we will continue to monitor its performance.

Feeder AX168 - Alexandra

Planned SAIDI	3.89
Planned SAIFI	0.010
Unplanned SAIDI	9.33
Unplanned SAIFI	0.155

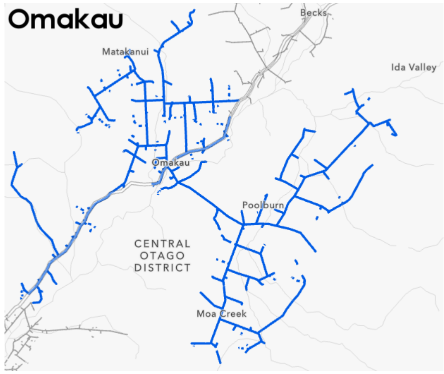
- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned feeder performance has been well below expectations in RY23. Vegetation has been a major root cause of failures, and we maintained over 100 trees on the feeder in RY23 as part of our ongoing vegetation programme. Protection system errors have also contributed to the feeder's performance. Now that we have identified the issues, we expect to see improvements.

Feeder AX169 - Alexandra

Planned SAIDI	2.51
Planned SAIFI	0.005
Unplanned SAIDI	1.32
Unplanned SAIFI	0.017

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance is within our expectations for the feeder.

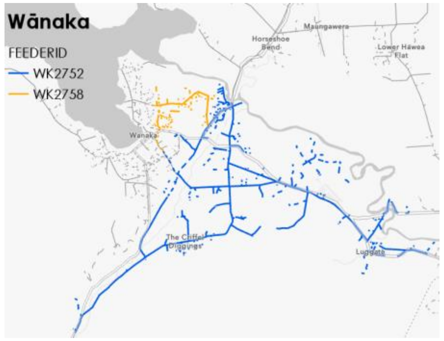
Omakau area



Feeder OM656 – Omakau	
Planned SAIDI	3.21
Planned SAIFI	0.037
Unplanned SAIDI	9.82
Unplanned SAIFI	0.068

- This feeder has previously been identified as having poor reliability performance in RY22.
- We have commissioned several projects in the area to improve reliability for customers:
  - Omakau zone substation upgrade is in progress,
  - Diesel generator installed as a back-up supply,
  - Acoustic inspection project completed in June 2022 to identify defects that are difficult to spot during visual inspections,
  - Installation of additional recloser devices which help to identify faults and to limit the impact of faults on customers.
- We are also exploring options to improve the network configuration and security of supply to the area.

Upper Clutha – Wanaka, Camp Hill and Queensbury areas

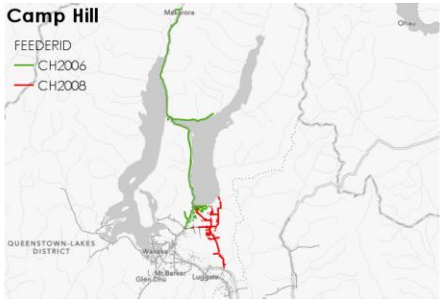


Feeder WK2752 – Wānaka	
Planned SAIDI	4.60
Planned SAIFI	0.015
Unplanned SAIDI	9.20
Unplanned SAIFI	0.225

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance has been below expectations, mainly due to a rare situation where one of the two upper Clutha circuits was out of service and the second circuit tripped. We have made an adjustment to our protection settings and put in place improved operational practices to prevent a reoccurrence. We will monitor other contributing factors on the feeder, but we do not expect that additional actions will be required to improve unplanned performance for the feeder.

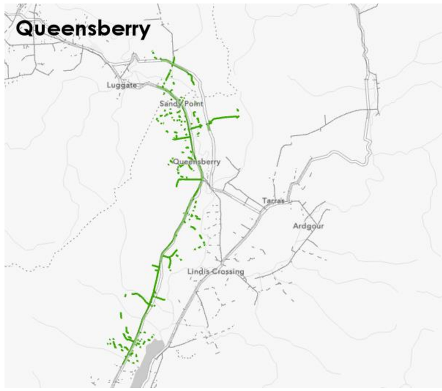
Feeder WK2758 – Wānaka	
Planned SAIDI	2.44
Planned SAIFI	0.007
Unplanned SAIDI	2.06
Unplanned SAIFI	0.050

- Unplanned performance has been below expectations due to issues on the Upper Clutha circuit as described above.
- We have made changes in the Upper Clutha region to improve reliability. We expect that no additional actions will be required for the feeder.



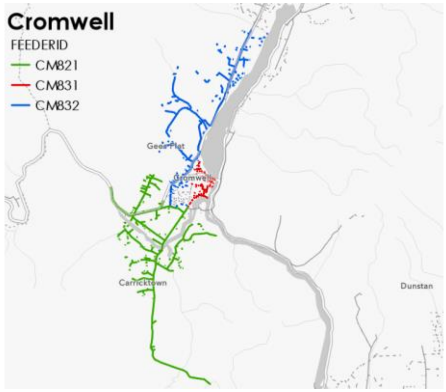
Feeder CH2006 – Camp Hill		
Planned SAIDI	4.97	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – Unplanned performance has been below expectations due to issues on the Upper Clutha circuit as described above. We expect that no additional actions will be required for reliability performance to return to expected levels.
Planned SAIFI	0.015	
Unplanned SAIDI	5.34	
Unplanned SAIFI	0.055	

Feeder CH2008 – Camp Hill		
Planned SAIDI	5.19	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – Unplanned performance has been well below expectations for this feeder. The Upper Clutha issues have contributed to the poor performance, and our actions in this area will improve reliability for customers.
Planned SAIFI	0.01	
Unplanned SAIDI	6.99	
Unplanned SAIFI	0.153	



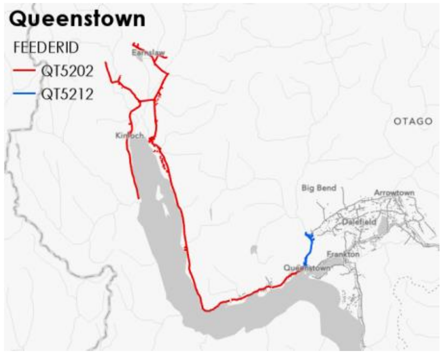
Feeder CB2423 – Queensberry		
Planned SAIDI	2.50	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – Unplanned performance is within our expectations for the feeder.
Planned SAIFI	0.008	
Unplanned SAIDI	0.70	
Unplanned SAIFI	0.013	

Cromwell area



Feeder CM821 – Cromwell		
Planned SAIDI	0.32	– Unplanned performance is within our expectations for this long rural feeder.
Planned SAIFI	0.001	
Unplanned SAIDI	1.59	
Unplanned SAIFI	0.032	
Feeder CM831 – Cromwell		
Planned SAIDI	0.36	– The feeder has underperformed against our expectations for this year. This was driven by a one-off event in March 2023. We have no immediate actions for this feeder, but we will continue to monitor its performance.
Planned SAIFI	0.003	
Unplanned SAIDI	2.94	
Unplanned SAIFI	0.064	
Feeder CM832 – Cromwell		
Planned SAIDI	2.98	– This feeder has underperformed against our expectations for this year. We are aware of these issues and have engaged with the Pisa Moorings community around our plans for improvement. – As part of these improvements, we have performed actions to improve voltage quality in the area. We have also analysed the network configuration in this area to identify improvements that may reduce the impact of planned and unplanned outages on customers.
Planned SAIFI	0.007	
Unplanned SAIDI	11.36	
Unplanned SAIFI	0.148	

Queenstown township and Glenorchy areas

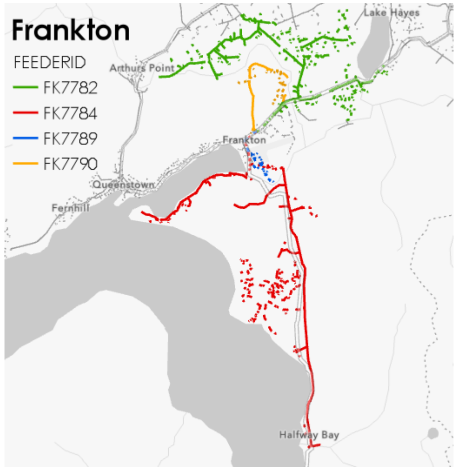


Feeder QT5202 – Queenstown		
Planned SAIDI	1.90	– Unplanned performance is within our expectations for a long rural feeder. – We have installed remote operation capability on our generator at Glenorchy as a back-up for outages and planned works, and we have also increased the frequency of vegetation patrols due to known issues.
Planned SAIFI	0.004	
Unplanned SAIDI	4.03	
Unplanned SAIFI	0.043	
Feeder QT5212 – Queenstown		
Planned SAIDI	3.35	– High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required. – Unplanned performance is within our expectations for the feeder.
Planned SAIFI	0.023	
Unplanned SAIDI	0.39	
Unplanned SAIFI	0.010	

Feeder CB5308 – Fernhill	
Planned SAIDI	0.50
Planned SAIFI	0.003
Unplanned SAIDI	8.06
Unplanned SAIFI	0.106

- This feeder has previously been identified as having poor reliability performance in RY22.
- We have commissioned a network upgrade project to reduce the impact of unplanned outages on customers. Once completed, this work will reduce unplanned SAIDI and SAIFI in the area.

Frankton area



Feeder FK7782 – Frankton	
Planned SAIDI	3.39
Planned SAIFI	0.009
Unplanned SAIDI	1.36
Unplanned SAIFI	0.016

- This feeder has previously been identified as having poor reliability performance in RY22.
- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance for RY23 is within our expectations for the feeder.

Feeder FK7784 – Frankton	
Planned SAIDI	6.43
Planned SAIFI	0.024
Unplanned SAIDI	0.58
Unplanned SAIFI	0.009

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance is within our expectations for the feeder.

Feeder FK7789 – Frankton	
Planned SAIDI	3.77
Planned SAIFI	0.014
Unplanned SAIDI	1.79
Unplanned SAIFI	0.026

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned SAIFI performance is below expectations for this feeder. Customers experienced only two outage days during the year, but SAIFI levels were increased due to multiple interruptions on these days.

Feeder FK7790 – Frankton	
Planned SAIDI	0.77
Planned SAIFI	0.002
Unplanned SAIDI	1.84
Unplanned SAIFI	0.035

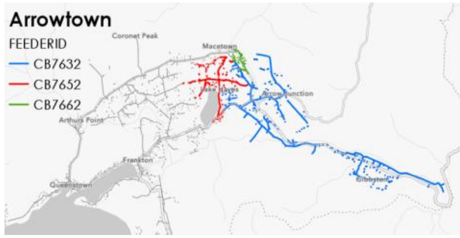
- Feeder underperformed against our expectations for this year. This was driven by a one-off event in March 2023. We have no immediate actions for this feeder, but we will continue to monitor its performance.

Arrowtown area

We have experienced issues with the sensitivity of our earth fault protection systems in the area due to the highly resistive soils. As a result, distribution circuits are prone to trip during planned switching operations.

We have reviewed our switching practices as a short-term solution and implemented measures to ensure that these faults do not reoccur. We have initiated an investigation with an external consultant to advise on a longer-term solution.

We also have an Arrowtown Ring upgrade project in progress which will help to improve security of supply to the Arrowtown area.

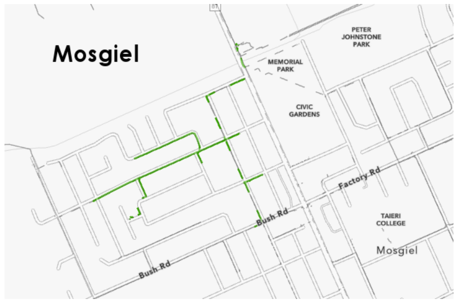


Feeder CB7632 – Arrowtown		
Planned SAIDI	2.80	– This feeder has previously been identified as having poor reliability performance in RY22. – We have commissioned a network upgrade project to reduce the impact of unplanned outages on customers. Once completed, this work will reduce unplanned SAIDI and SAIFI in the area. – We expect that the Arrowtown Ring project and improvements to our protection systems will improve feeder reliability towards expected performance.
Planned SAIFI	0.008	
Unplanned SAIDI	6.06	
Unplanned SAIFI	0.096	

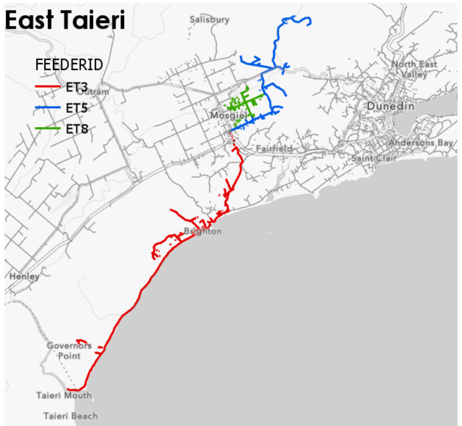
Feeder CB7652 – Arrowtown		
Planned SAIDI	1.78	– This feeder has previously been identified as having poor reliability performance in RY22. – We expect that the Arrowtown Ring project and improvements to our protection systems will improve feeder reliability towards expected performance.
Planned SAIFI	0.006	
Unplanned SAIDI	3.08	
Unplanned SAIFI	0.069	

Feeder CB7662 – Arrowtown		
Planned SAIDI	4.51	– This feeder has previously been identified as having poor reliability performance in RY22. – We expect that the Arrowtown Ring project and improvements to our protection systems will improve feeder reliability towards expected performance.
Planned SAIFI	0.010	
Unplanned SAIDI	0.66	
Unplanned SAIFI	0.045	

East Taieri area



Feeder MG3 – Mosgiel		
Planned SAIDI	3.57	– The feeder has experienced several planned outages for required asset replacements. We expect fewer outages in future now that the work has been completed. – The feeder has experienced no unplanned outages in RY23.
Planned SAIFI	0.008	
Unplanned SAIDI	0.00	
Unplanned SAIFI	0.000	



Feeder ET3 – East Taieri

Planned SAIDI	3.06
Planned SAIFI	0.08
Unplanned SAIDI	1.65
Unplanned SAIFI	0.014

- High planned SAIDI value was driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- This feeder has previously been identified as having poor reliability performance in RY22. We undertook an acoustic inspection which identified equipment defects not visible to the naked eye. Remediation of the identified defects is expected to further improve the RY23 performance in RY24.

Feeder ET5 – East Taieri

Planned SAIDI	0.97
Planned SAIFI	0.002
Unplanned SAIDI	1.85
Unplanned SAIFI	0.025

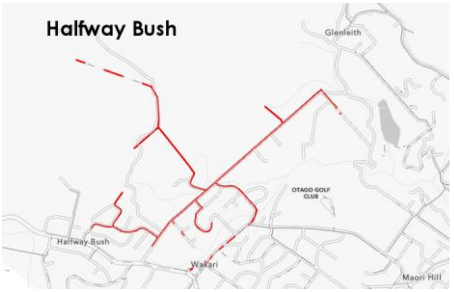
- This feeder has underperformed in RY23 in terms of unplanned reliability, and we were unable to identify a clear cause for several outages. Acoustic inspections have helped to identify potential issues that have led to these faults.
- We expect to see improvements going forward, but we will continue to monitor this feeder.

Feeder ET8 – East Taieri

Planned SAIDI	0.74
Planned SAIFI	0.002
Unplanned SAIDI	2.48
Unplanned SAIFI	0.065

- Unplanned performance has been below expectations for this feeder. The outages on this feeder for RY23 are predominantly due to asset failure.
- Acoustic inspections were carried out in the East Taieri area in February 2023. These inspections help to identify defects that are difficult to identify during normal visual inspections. We have already remediated any urgent defects, and the remainder will be addressed as part of other planned works. We will continue to monitor performance over time to ensure that our actions have sufficiently addressed the issue.

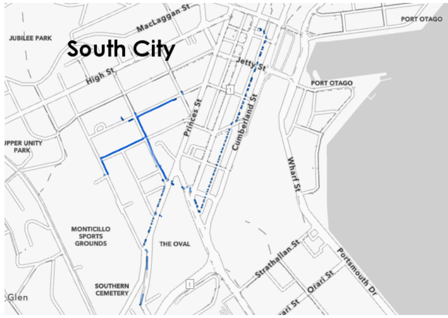
Dunedin City area



Feeder HB13 – Halfway Bush, Dunedin

Planned SAIDI	2.73
Planned SAIFI	0.009
Unplanned SAIDI	0.77
Unplanned SAIFI	0.015

- The feeder has experienced several planned outages for required asset replacements. We expect fewer outages in future now that the work has been completed.
- Unplanned performance has also been below expectations for an urban feeder. These outages have been due to external causes (vegetation and weather). We will continue to monitor performance, but we do not expect the trend to continue.

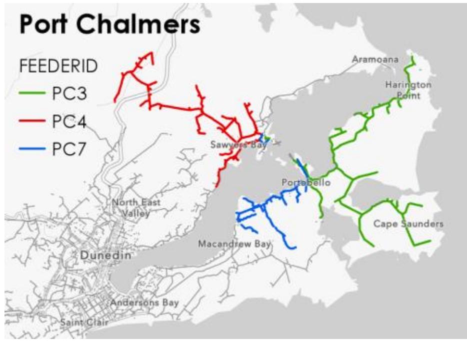


Feeder SC9 – South City, Dunedin

Planned SAIDI	3.41
Planned SAIFI	0.008
Unplanned SAIDI	0.00
Unplanned SAIFI	0.000

- The feeder has experienced several planned outages for required asset replacements. We expect fewer outages in future now that the work has been completed.
- The feeder has experienced no unplanned outages in RY23.

Port Chalmers area



Feeder PC3 – Port Chalmers

Planned SAIDI	2.78
Planned SAIFI	0.005
Unplanned SAIDI	2.03
Unplanned SAIFI	0.012

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance is within our expectations for the feeder.

Feeder PC4 – Port Chalmers

Planned SAIDI	2.03
Planned SAIFI	0.005
Unplanned SAIDI	3.42
Unplanned SAIFI	0.048

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance was below expectations this year. This was driven by a significant weather event in March 2023 which resulted in several trees through our lines. We have no immediate actions for this feeder, but we will continue to monitor its performance.

Feeder PC7 – Port Chalmers

Planned SAIDI	2.39
Planned SAIFI	0.004
Unplanned SAIDI	3.86
Unplanned SAIFI	0.046

- High planned SAIDI values were driven by large replacement programmes in the area in RY23. Now that these works have been completed, we expect lower levels of planned outages required.
- Unplanned performance was below expectations this year. This was driven by a significant weather event in March 2023 which resulted in several trees through our lines. We have no immediate actions for this feeder, but we will continue to monitor its performance.

8. THE RY23 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 1: Renewal Capex – Dunedin pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$31,740,330	$28,341,602	-11%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Poles	$5,776,911	$7,061,385	22%
Crossarms	$3,102,700	$3,992,246	29%
Distribution conductor	$3,589,441	$4,403,915	23%
Distribution cables	$1,909,603	$2,368,934	24%

The asset replacement and renewal capital expenditure in the Dunedin pricing region allowed us to address safety matters while also improving asset health and reliability. Actual asset replacement and renewal capital expenditure was lower than the PPDP forecast due to lower expenditure on zone substations and ground mounted switchgear. Expenditure on these portfolios was impacted by resource constraints and cost escalation across the wider programme causing reprioritisation of our plan.

Poles, crossarms and distribution conductor expenditure in the Dunedin pricing region was undertaken at a higher cost than forecast due to escalating costs and the evolving maturity of our forecast processes. Higher distribution cable expenditure reflects greater reactive works than forecast.

Table 2: Growth and security Capex – Dunedin pricing region

GROWTH AND SECURITY CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System Growth	$2,108,730	$461,913	-78%

System growth expenditure in the Dunedin pricing region was lower than forecast due to delays to the Smith Street to Willowbank 33kV cable link project. This work will progress in RY24 but is subject to ongoing coordination of trenching with Dunedin City Council which is undertaking work in the area.

Table 3: Other network Capex – Dunedin pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$15,000	$110,884	639%
Legislative and regulatory	$0	$0	0%
Other reliability, safety and environment	$0	$0	0%
Consumer connection	$2,300,000	$2,979,661	30%
Asset relocations	$400,000	$249,744	-38%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Consumer connection – capacity event	$1,075,873	$1,755,534	63%

Due to consumer connections being initiated by consumers, we often do not have good visibility of future pipeline growth. The trend was exceeded in RY23, which together with cost escalations, resulted in higher than forecast consumer connection capital expenditure.

Expenditure on quality of supply was higher than forecast due to the variable and reactionary nature of customer enquiries. These higher costs resulted in less expenditure on asset relocations than expected.

Table 4: Network Opex – Dunedin pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$5,634,205	$6,185,098	10%
Service interruptions and emergencies	$2,406,482	$1,515,526	-37%
Vegetation	$1,991,992	$2,825,384	42%
Asset replacement and renewal	$0	$0	0%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Preventive	$3,140,220	$3,896,081	24%
Vegetation	$1,991,992	$2,825,384	42%

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 though improved inspection and data collection processes (preventive) and correct more asset defects (corrective).

Vegetation costs were higher in Dunedin as we focused on vegetation dense areas that were responsible for a number of faults.

Table 5: Non-network Opex – Dunedin pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$8,243,783	$8,286,496	1%
Business support	$8,378,279	$8,256,104	-1%

Non-network operational expenditure was closely aligned to the PPDP forecast for RY23.

8.1.2. Central Otago and Wanaka pricing region

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

Table 6: Renewal Capex – Central Otago and Wanaka pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$19,162,705	$18,595,377	-3%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Poles	$5,435,431	$7,455,732	37%

Zone substations	$3,636,837	$5,036,684	38%

Our total asset replacement and renewal expenditure in Central Otago and Wanaka for RY23 was broadly consistent with our PPDP forecast. While we spent more on poles due to new asset inspection information and more on zone substations to meet unforeseen project costs, we spent less on crossarms and distribution conductor as a consequence of diverting resources.

Table 7: Growth and security Capex – Central Otago and Wanaka pricing region

GROWTH AND SECURITY CAPEX	FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System Growth	$7,585,011	$10,865,616	43%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Omakau new zone substation	$1,807,536	$3,419,330	89%

Additional investment was required in Central Otago and Wanaka to address growth related demand not forecast in the PPDP. Non-forecast projects undertaken to address that growth included Letts Gully and Springvale Road reinforcement to provide a back-up to Clyde township in the event of Clyde-Earnscleugh zone substation planned and unplanned outages. We also completed the installation of an 11kV feeder at Cardona.

The cost to upgrade the Omakau zone substation was also revised to account for additional expenditure for the installation of a generator, previously underestimated costs, unforeseen challenges at the site and cost inflation. The project remains on schedule to deliver a transformer with greater supply capacity, greater potential for future substation expansion as well as an on-site generator and ability to connect our mobile substation.

Table 8: Other network Capex – Central Otago and Wanaka pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$1,241,310	$602,697	-45%
Legislative and regulatory	$0	$0	0%
Other reliability, safety and environment	$0	$2,155,596	0%
Consumer connection	$8,063,694	$10,221,591	27%
Asset relocations	$550,000	$1,151,617	109%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Reliability safety and environment	$1,241,310	$2,758,293	122%
Consumer connection – capacity event	$3,771,961	$5,929,858	57%

Quality of supply expenditure was less than forecast, largely due to the variable number of customer enquiries and the reactionary nature of our response to remediate any issues. Expenditure on reliability, safety and environment was higher than forecast due to the installation of generators at the Omakau and Camp Hill zone substations. The generators address a gap (against our security of supply guideline) in network security in the Omakau and Lake Hawea regions. Each region is supplied via a single 33kV line with limited 11kV back-up. Each 2MW generator can support the 11kV supply to meet the majority of demand in the region and help with supply during planned maintenance work on the 33kV lines.

Continued growth in the region, together with escalating costs, meant our consumer connection expenditure exceeded both the base and capacity event forecasts in the PPDP. Asset relocation expenditure was also higher than the PPDP forecast mainly due to Waka Kotahi projects in the area.

Table 9: Network Opex – Central Otago and Wanaka pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$2,843,357	$4,570,292	61%
Service interruptions and emergencies	$1,443,889	$895,281	-38%
Vegetation	$2,475,784	$1,459,878	-41%
Asset replacement and renewal	$0	$0	0%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Preventive	$1,884,132	$3,215,762	71%
Corrective	$959,225	$1,354,530	41%

Total network operational expenditure was broadly consistent with our PPDP forecasts for RY23.

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 though improved inspection and data collection processes (preventive) and correct more asset defects (corrective).

While we carried out our planned vegetation-related inspections in RY23, the costs associated with maintenance arising from inspections was lower than expected.

Table 10: Non-network Opex – Central Otago and Wanaka pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$3,878,768	$3,408,667	-12%
Business support	$3,305,866	$3,354,714	1%

Business support expenditure was generally consistent with the PPDP forecast. System operations and network support expenditure was lower than expected due to lower expenditure on the Upper

Clutha DER solution. The rate of uptake of the SolarZero offering and other initiatives has been slower than the rate we originally forecast.

8.1.3. Queenstown region

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

Table 11: Renewal Capex – Queenstown pricing region

RENEWAL CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Asset replacement and renewal	$5,328,225	$7,667,286	44%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Poles	$2,621,754	$4,081,466	56%
Distribution conductor	$0	$1,137,370	-

During RY23 we spent more on poles than forecast because our pole inspection programme identified more poles with a higher risk rating than we forecast. Unforeseen distribution conductor replacement was also undertaken in Arrowtown to mitigate safety issues identified from updated asset health information. Asset replacement and renewal expenditure exceeded the forecast for these reasons.

Table 12: Growth and security Capex – Queenstown pricing region

GROWTH AND SECURITY CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System growth	$3,005,517	$6,186,215	106%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Arrowtown 33 kV Ring Upgrade	$2,885,516	$5,289,901	83%

Higher system growth expenditure in RY23 was related mainly to the Arrowtown 33kV Ring Upgrade project. RY23 apportioned costs were higher due to the project being brought forward, escalating costs and the evolving maturity of our forecasting processes. An 'upstream' upgrade to accommodate a large customer was also a driver of higher than forecast system growth expenditure.

Table 13: Other network Capex – Queenstown pricing region

OTHER NETWORK CAPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Quality of Supply	$149,310	$457,975	207%
Legislative and regulatory	$0	$0	-
Other reliability, safety and environment	$0	$0	-

Consumer connection	$3,200,000	$2,044,881	-36%
Asset relocations	$1,733,000	$2,326,355	34%
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Asset relocations - capacity event	$505,378	$1,098,733	117%

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 any issues. Total other network capex in the Queenstown region was broadly consistent with the PPDP forecast for RY23. There was higher asset relocation expenditure due to large customer driven moving works including work undertaken for the Queenstown Lakes District Council. This was offset by lower than forecast consumer connection expenditure. Due to consumer connections being initiated by consumers, we often do not have good visibility of future pipeline growth. Actual consumer connection expenditure was less than we expected in RY23 due in part to the existence of a competing network in the region.

Table 14: Network Opex – Queenstown pricing region

NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
Routine and corrective maintenance and inspection	$1,639,778	$1,529,527	-7%
Service interruptions and emergencies	$962,593	$470,654	-51%
Vegetation	$788,176	$1,180,687	50%
Asset replacement and renewal	$0	$0	-
Projects or programmes exceeding proposed expenditure under clause 1.7.1(a)			
Vegetation	$788,176	$1,180,687	50%

Routine and corrective maintenance and inspection expenditure was broadly consistent with our PPDP forecast for RY23.

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 15: Non-network Opex – Queenstown pricing region

NON-NETWORK OPEX	PPDP FORECAST $	ACTUAL $	VARIANCE
Information disclosure category			
System operations and network support	$2,136,267	$2,170,912	2%
Business support	$2,171,120	$2,162,950	0%

Non-network operational expenditure was closely aligned to the PPDP forecast for RY23.

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 RY23 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 also 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. 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 RY23. Explanations are provided to assist with understanding, including why the number of assets replaced may have varied from the PPDP forecast.

Table 16: Support structure assets replaced or renewed – Dunedin pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	457	411
	Total average cost of replacing the assets	$12,670	$21,507

Crossarms	Number of assets replaced	1002	930
	Total average cost of replacing the assets	$2,927	$4,022

Reprioritising expenditure to poles and crossarms renewals allowed us to deliver quantities close to our PPDP forecast.

The average cost of replacing poles was higher in the Dunedin pricing region compared to the average forecast cost across the whole network. This was due to escalating costs and the evolving maturity of our forecasting processes as they related to traffic management and pole replacement complexities, including multi-voltage crossarms and the extent of associated asset replacements. Crossarm costs were also higher than forecast, mainly due to more associated assets being replaced than forecast.

Looking forward, updated asset inspection information and our maturing network risk assessment practices, are expected to reduce the number of pole assets needing to be replaced from RY25 to RY26.

Table 17: Overhead conductor assets replaced or renewed – Dunedin pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	0.000 km	0
	Total average cost of replacing the assets	$284,217	-
Distribution conductor	Number of assets replaced	24.080 km	14.264
	Total average cost of replacing the assets	$154,884	$313,083
Low voltage conductor	Number of assets replaced	0.830 km	0.452
	Total average cost of replacing the assets	$131,275	$64,560

Resource constraints limited the quantity of distribution conductor we could replace in RY23. The focus was on low strength conductor in higher risk areas. The average cost of replacement was higher due to escalating costs and the maturing nature of our forecasting processes including in relation to the cost of replacing assets in higher risk areas and pole complexities including the requirement to replace associated assets.

The low voltage conductor work was undertaken to address a high fault rate.

Table 18: Cable assets replaced or renewed – Dunedin pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	0.000km	0.000
	Total average cost of replacing the assets	$1,213,058	-
Distribution cable	Number of assets replaced	0.130 km	0.407
	Total average cost of replacing the assets	$433,925	$7,663,279
Low voltage cable	Number of assets replaced	0.130 km	0.225
	Total average cost of replacing the assets	$146,739	$141,051

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 underground nature of cables, however individual project costs are within expectations.

During RY23 we also made our network safer through replacing another 45 cast iron pot heads.

Table 19: Zone Substation assets replaced or renewed – Dunedin pricing region

ZONE SUBSTATION ASSET CATEGORY		PPDP FORECAST	ACTUAL
Power transformers	Number of assets replaced	2	0
	Total average cost of replacing the assets	$1,578,931	-
Indoor switchgear	Number of assets replaced	15	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	0
	Total average cost of replacing the assets	$131,665	-
Buildings and grounds	Number of assets replaced	0	0
	Total average cost of replacing the assets	$1,008,170	-

We made good progress on the Andersons Bay zone substation project in RY23, however, due to resource constraints the delivery of the forecast asset quantities related to this project will be delivered in RY24. While we undertook design and enabling works for the Green Island zone substation, reallocation of capital expenditure was required to address growth and cost escalation, meaning that the quantities forecast for this project were not delivered in RY23.

Table 20: Distribution switchgear assets replaced or renewed – Dunedin pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	26	20
	Total average cost of replacing the assets	$83,945	$136,289
Pole mounted fuses	Number of assets replaced	8	10
	Total average cost of replacing the assets	$5,275	$5,350
Pole mounted switches	Number of assets replaced	2	9
	Total average cost of replacing the assets	$15,182	$16,805
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	16	14
	Total average cost of replacing the assets	$5,667	$31,898

Total distribution switchgear replacements under the switchgear programmes were slightly below the quantities forecast in the PPDP for RY23.

Some asset types were more expensive to replace due to escalating costs and the evolving maturity of our forecast processes including in relation to reactive works, associated assets, traffic management and the mix of asset types within fleets.

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

DISTRIBUTION TRANSFORMERS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ancillary distribution substation	Number of assets replaced	120	11
	Total average cost of replacing the assets	$4,623	$7,797
Ground mounted distribution transformers	Number of assets replaced	2	5
	Total average cost of replacing the assets	$50,748	$50,321
Pole mounted distribution transformers	Number of assets replaced	5	11
	Total average cost of replacing the assets	$32,592	$36,808

In RY23 we focused on replacing certain types of surge arrestors in our ancillary distribution substation assets fleet. The replacement of other surge arrestors in the fleet were deferred. The average costs are higher than forecast due to escalating costs and the evolving maturity of our forecast processes.

The ground mounted and pole mounted distribution transformer assets replaced in RY23 were mainly undertaken as reactive works which was higher than provided for in the PPDP.

Table 22: Secondary systems assets replaced or renewed – Dunedin pricing region

SECONDARY SYSTEMS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Protection	Number of assets replaced	44	13
	Total average cost of replacing the assets	$20,633	$30,449
DC systems	Number of assets replaced	7	1
	Total average cost of replacing the assets	$74,086	$128,366
Remote terminal units	Number of assets replaced	0	0
	Total average cost of replacing the assets	$111,729	$-

In RY23 we commissioned a project that was commenced in RY22. Other works forecast to be undertaken on secondary systems have been aligned with our broader zone substation works. For this reason, asset quantities delivered here were less than forecast. The average cost to deliver secondary system assets was higher than forecast. This was due to escalating costs and the evolving maturity of our forecasting processes as they relate to the extent of associated asset replacements and site-specific complexities.

8.2.2. Central Otago and Wanaka 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 Wanaka pricing region as part of our asset replacement and renewal expenditure during RY23.

Table 23: Support structure assets replaced or renewed – Central Otago and Wanaka pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	430	724
	Total average cost of replacing the assets	$12,670	$13,295
Crossarms	Number of assets replaced	1031	798
	Total average cost of replacing the assets	$2,927	$4,168

More poles were replaced in RY23 than forecast as our inspection programme identified more poles with a higher risk rating than initially assumed. These pole replacements were prioritised over crossarm replacement.

The average cost of replacing poles was marginally higher in the Central Otago and Wanaka region than forecast due to escalating costs. Crossarm costs were also higher than forecast due to more associated assets being replaced than forecast and escalating costs.

Looking forward, updated asset inspection information and our maturing network risk assessment practices are expected to reduce the number of pole assets needing to be replaced from RY25 to RY26.

Table 24: Overhead conductor assets replaced or renewed – Central Otago and Wanaka pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	0	0
	Total average cost of replacing the assets	$284,217	-
Distribution conductor	Number of assets replaced	26.950	19.947
	Total average cost of replacing the assets	$154,884	$115,264
Low voltage conductor	Number of assets replaced	2.836	0.013
	Total average cost of replacing the assets	$131,275	$152,314

Conductor replacement quantities in the Central Otago and Wanaka region were less than forecast as resources were reprioritised to address conductor safety matters identified in the Queenstown pricing region. The low voltage conductor replacement was undertaken as reactive work.

Consistent with the PPDP plan, no subtransmission conductor was replaced.

Table 25: Cable assets replaced or renewed – Central Otago and Wanaka pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	0.000	0

	Total average cost of replacing the assets	$1,213,058	-
Distribution cable	Number of assets replaced	0.130	0.022
	Total average cost of replacing the assets	$433,925	$7,574,963
Low voltage cable	Number of assets replaced	0.130	0.031
	Total average cost of replacing the assets	$146,739	$613,507

We replaced small portions of distribution cables as reactive works, which were provided for in the forecast. The reactive works distort the disclosed average cost because of the underground nature of the cables which can make it difficult to forecast costs, however individual project costs were within expectation.

Table 26: Zone Substation assets replaced or renewed – Central Otago and Wanaka 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	16	0
	Total average cost of replacing the assets	$139,935	-
Outdoor switchgear	Number of assets replaced	2	0
	Total average cost of replacing the assets	$144,168	-
Ancillary zone substation equipment	Number of assets replaced	1	0
	Total average cost of replacing the assets	$131,665	-
Buildings and grounds	Number of assets replaced	3	0
	Total average cost of replacing the assets	$1,008,170	-

In RY23 we made progress on the Alexandra outdoor to indoor switchgear conversion, but we were not able to complete the project due to global supply pressures. We also deferred building works at Clyde-Earnscleugh while we reconsidered the network configuration in response to changing load requirements.

Table 27: Distribution switchgear assets replaced or renewed – Central Otago and Wanaka pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	0	1
	Total average cost of replacing the assets	$83,945	$45,226
Pole mounted fuses	Number of assets replaced	5	0
	Total average cost of replacing the assets	$5,275	-
Pole mounted switches	Number of assets replaced	8	0
	Total average cost of replacing the assets	$15,182	-
Reclosers and sectionalisers	Number of assets replaced	0	1

	Total average cost of replacing the assets	$85,731	$121,810
Low voltage enclosures	Number of assets replaced	15	34
	Total average cost of replacing the assets	$5,667	$4,425

Pole mounted switches were not replaced as planned due to global supply pressures. Reactive requirements impacted the number of other distribution switchgear assets that were replaced.

The average cost to replace assets varied from forecast because of global supply pressures, escalating costs, variations in the mix of asset types replaced under each fleet and assets being replaced under urgency.

Table 28: Distribution transformers assets replaced or renewed – Central Otago and Wanaka pricing region

DISTRIBUTION TRANSFORMERS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ancillary distribution substation	Number of assets replaced	123	135
	Total average cost of replacing the assets	$4,623	$2,510
Ground mounted distribution transformers	Number of assets replaced	0	1
	Total average cost of replacing the assets	$50,748	$3,554
Pole mounted distribution transformers	Number of assets replaced	22	2
	Total average cost of replacing the assets	$32,592	$18,779

In RY23 we focused on replacing certain types of surge arrestors in our ancillary distribution substation fleet. Pole mounted distribution transformer asset replacements were impacted by global supply pressures. The ground and pole mounted transformer replacements were undertaken as reactive works.

Replacing assets under urgency can be less expensive than the long term average due to only the primary assets being replaced.

Table 29: Secondary systems assets replaced or renewed – Central Otago and Wanaka pricing region

SECONDARY SYSTEMS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Protection	Number of assets replaced	42	0
	Total average cost of replacing the assets	$20,633	-
DC systems	Number of assets replaced	3	0
	Total average cost of replacing the assets	$74,086	-
Remote terminal units	Number of assets replaced	0	0
	Total average cost of replacing the assets	$111,729	-

Work forecast to be undertaken on secondary systems has been aligned with our broader zone substation works. For this reason, asset quantities forecast were not delivered here.

8.2.3. 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 RY23.

Table 30: Support structure assets replaced or renewed – Queenstown pricing region

SUPPORT STRUCTURES ASSET CATEGORY		PPDP FORECAST	ACTUAL
Poles	Number of assets replaced	207	243
	Total average cost of replacing the assets	$12,670	$17,091
Crossarms	Number of assets replaced	0	232
	Total average cost of replacing the assets	$2,927	$5,459

Pole replacement quantities under the pole programme exceeded the PPDP forecast for RY23. The crossarm replacement programme was brought forward to RY23 as our pole risk profile improved due to updated asset inspection information and our maturing network risk assessment practices.

The total average cost of replacing poles and crossarms was higher due to escalating costs and the evolving maturity of our forecasting processes including the extent of associated assets replacement required.

Table 31: Overhead conductor assets replaced or renewed – Queenstown pricing region

OVERHEAD CONDUCTOR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission conductor	Number of assets replaced	0.600	0.000
	Total average cost of replacing the assets	$284,217	-
Distribution conductor	Number of assets replaced	0.000	4.965
	Total average cost of replacing the assets	$154,884	$266,638
Low voltage conductor	Number of assets replaced	0.000	0.000
	Total average cost of replacing the assets	$131,275	-

In RY23 we replaced 5.0km of distribution conductor to address asset health issues that were not evident at the time of the PPDP. The average cost of replacement was higher due to escalating costs and the maturing nature of our forecasting processes including that RY23 replacement occurred in challenging and complex areas with higher than normal design and associated asset costs.

No low voltage conductor was planned to be replaced in RY23. Some subtransmission conductor was planned to be replaced, however, due to land access and consenting delays, the work was delayed.

Table 32: Cable assets replaced or renewed – Queenstown pricing region

CABLE ASSET CATEGORY		PPDP FORECAST	ACTUAL
Subtransmission cable	Number of assets replaced	0.000	0
	Total average cost of replacing the assets	$1,213,058	-

Distribution cable	Number of assets replaced	0.000	0.119
	Total average cost of replacing the assets	$433,925	$1,359,961
Low voltage cable	Number of assets replaced	0.000	0
	Total average cost of replacing the assets	$146,739	-

There was no planned replacement of specific cable assets in RY23. We did replace small portions of distribution cables as reactive works. The reactive nature of the work distorts the disclosed average cost because of the underground nature of the cables, however individual project costs are within expectation.

Table 33: 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	0	0
	Total average cost of replacing the assets	$139,935	-
Outdoor switchgear	Number of assets replaced	5	1
	Total average cost of replacing the assets	$144,168	$51,439
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	0	0
	Total average cost of replacing the assets	$1,008,170	-

PPDP planned work at the Queenstown Zone substation site was reprioritised behind other initiatives at the site that were deemed higher risk than previously understood. Works at the site were also delayed due to land access issues.

Table 34: Distribution switchgear assets replaced or renewed – Queenstown pricing region

DISTRIBUTION SWITCHGEAR ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ground mounted switchgear	Number of assets replaced	2	4
	Total average cost of replacing the assets	$83,945	$102,956
Pole mounted fuses	Number of assets replaced	0	0
	Total average cost of replacing the assets	$5,275	-
Pole mounted switches	Number of assets replaced	0	1
	Total average cost of replacing the assets	$15,182	$16,066
Reclosers and sectionalisers	Number of assets replaced	0	1
	Total average cost of replacing the assets	$85,731	$98,771
Low voltage enclosures	Number of assets replaced	0	13
	Total average cost of replacing the assets	$5,667	$5,294

Distribution switchgear replacement quantities exceeded the PPDP forecast for RY23 largely due to the higher quantity of low voltage enclosure replacements undertaken as reactive works. Total average costs were within latest expected ranges.

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

DISTRIBUTION TRANSFORMERS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Ancillary distribution substation	Number of assets replaced	20	0
	Total average cost of replacing the assets	$4,623	-
Ground mounted distribution transformers	Number of assets replaced	0	1
	Total average cost of replacing the assets	$50,748	$29,443
Pole mounted distribution transformers	Number of assets replaced	0	1
	Total average cost of replacing the assets	$32,592	$53,764

In RY23 we focused on replacing certain types of surge arrestors in our ancillary distribution substation assets fleet. The replacements of other surge arrestors in the fleet were deferred.

The ground and pole mounted distribution transformers replaced during the year were reactive replacements. The ground mounted and pole mounted distribution transformer assets replaced in RY23 were mainly undertaken as reactive works which was higher than provided for in the PPDP.

Table 36: Secondary systems assets replaced or renewed – Queenstown pricing region

SECONDARY SYSTEMS ASSET CATEGORY		PPDP FORECAST	ACTUAL
Protection	Number of assets replaced	0	1
	Total average cost of replacing the assets	$20,633	$23,781
DC systems	Number of assets replaced	0	0
	Total average cost of replacing the assets	$74,086	-
Remote terminal units	Number of assets replaced	0	0
	Total average cost of replacing the assets	$111,729	-

One protection asset was replaced in Queenstown as reactive works.

8.3. VEGETATION MANAGEMENT

Table 37 sets out the the percentage of the network that we have either inspected or felled, trimmed, removed or sprayed in RY23 as part of our three-year vegetation management plan. RY23 was the first 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 37: Vegetation management

	DUNEDIN		CENTRAL OTAGO AND WĀNAKA		QUEENSTOWN	
NATURE OF WORK	FORECAST	ACTUAL	FORECAST	ACTUAL	FORECAST	ACTUAL
Percentage of network inspected	40%	31%	47%	45%	60%	69%
Percentage of network felled, trimmed, removed or sprayed	34%	34%	46%	42%	53%	66%

8.4. SAFETY-RELATED INCIDENTS

Table 38 outlines the number of safety-related incidents that occurred on our network in RY23 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 section 1.1.

Table 38: Safety-related incidents

	Dunedin		Central Otago and Wānaka		Queenstown	
	RY22	RY23	RY22	RY23	RY22	RY23
Number of safety-related incidents	96	104	76	84	11	30

8.5. Reliability

Table 39 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 40 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 39: Reliability – 5-year time series by pricing region

	RY23	RY22	RY21	RY20	RY19
Dunedin					
Planned SAIDI	117.91	134.62	87.10	70.62	139.45
Planned SAIFI	0.44	0.79	0.59	0.42	0.71
Unplanned SAIDI	65.05	51.47	59.30	91.41	66.41
Unplanned SAIFI	0.97	0.72	1.01	1.20	0.98

Central Otago and Wānaka					
Planned SAIDI	272.90	290.46	218.60	210.56	205.43
Planned SAIFI	0.88	0.92	0.99	3.53	0.85
Unplanned SAIDI	309.50	224.61	238.50	333.89	254.42
Unplanned SAIFI	5.18	3.33	2.72	1.16	3.61
Queenstown					
Planned SAIDI	236.58	298.17	193.70	116.52	138.73
Planned SAIFI	0.81	0.83	0.55	2.47	0.64
Unplanned SAIDI	267.98	248.36	137.60	171.77	449.20
Unplanned SAIFI	4.06	3.90	1.85	0.53	3.01

Table 40: Reliability – performance against the CPP Determination quality limits

Total network	
Planned SAIDI assessed value	110.34
Planned SAIFI assessed value	0.60
Unplanned SAIDI assessed value	106.49
Unplanned SAIFI assessed value	1.75
Planned accumulated SAIDI limit	979.80
Planned accumulated SAIFI limit	5.54
Unplanned SAIDI limit	124.94
Unplanned SAIFI limit	2.07

8.6. PLANNED INTERRUPTIONS

Table 41 sets out details on planned interruptions that we undertook during RY23.

Table 41: Planned interruptions

METRIC	RY23
Planned interruptions cancelled with more than 24 hours’ notice, but less than 10 working days' notice	70
Planned interruptions cancelled without notice	173
Planned interruptions for which Aurora gave additional notice	1204
Planned interruptions for which Aurora did not give additional notice	140
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	159
Unplanned interruptions that Aurora intentionally initiated to carry out work on our network that did not directly relate to a fault	165

Complaints

Table 42 sets 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 42: Complaints – Dunedin pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Voltage quality	22	22
Damage to property	11	3
Planned outage – unsuitable timing	10	10
Frequency of outages[1]	8	2
Duration of outage	7	12
Planned outage – not performed as notified	6	17
Contractor behaviour or service[3]	5	7
Planned outage – not notified[2]	5	2
Damage to appliances	3	1
Connection policies	2	14
Planned outage - Cancelled	2	10
Recovery of electrician fees due to a fault	1	18
Unauthorised access to private property	1	1
Vegetation management	1	1

1. Type of complaint with the greatest number of complaints received in RY22
2. Type of complaint with the second greatest number of complaints received in RY22
3. Type of complaint with the third greatest number of complaints received in RY22

Table 43: Complaints – Central Otago and Wanaka pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Voltage quality[2]	19	43
Frequency of outages[1]	10	11
Planned outage – not notified	9	11
Planned outage – unsuitable timing	5	14
Recovery of electrician fees due to a fault	4	10
Planned outage – not performed as notified	4	11
Damage to appliances	3	1
Pricing	3	37
Contractor behaviour or service[3]	2	17
Damage to property	2	1
Duration of outage	2	8
Planned outage - cancelled	2	24

Connection policies	1	133
Unauthorised access to private property	1	78

1. Type of complaint with the greatest number of complaints received in RY22
2. Type of complaint with the second greatest number of complaints received in RY22
3. Type of complaint with the third greatest number of complaints received in RY22

Table 44: Complaints – Queenstown pricing region

COMPLAINT TYPE	NUMBER OF COMPLAINTS	AVERAGE TIME TO RESOLVE (BUSINESS DAYS)
Planned outage - unsuitable timing	9	11
Contractor behaviour or service	5	29
Planned outage – not performed as notified	5	12
Voltage quality[2]	5	26
Connection policies[3]	3	14
Damage to property	3	1
Frequency of outages[1]	3	1
Planned outage - cancelled	2	18
Planned outage – not notified	2	10
Duration of outage	1	26
Unauthorised access to private property	1	1

1. Type of complaint with the greatest number of complaints received in RY22
2. Type of complaint with the second greatest number of complaints received in RY22
3. Type of complaint with the third greatest number of complaints received in RY22

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		

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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	
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	
low voltage network practices referred to in clause 2.5.4(1)(a); 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 to consumers of planned interruptions;	Clause 1.4.2(c)	Section 5.4

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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
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

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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)	
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

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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 8.2
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 8.2
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 8.3
felled, trimmed, removed, or sprayed;	Clause 1.7.3(b)	Section 8.3
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 8.5
planned SAIFI values;	Clause 1.8.2	Section 8.5
unplanned SAIDI values; and	Clause 1.8.3	Section 8.5
unplanned SAIFI values;	Clause 1.8.4	Section 8.5

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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 0
the number of each type of complaint;	Clause 1.9.1(b)	Section 0
the average time to resolve each type of complaint;	Clause 1.9.1(c)	Section 0
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 0 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 8.4
commentary on how the number of safety-related incidents compared against the previous disclosure year; and	Clause 1.9.2(b)	Section 1.1
any corrective actions taken in respect of these incidents;	Clause 1.9.2(c)	Section 1.1
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 8.5

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
planned SAIFI assessed value, unplanned SAIFI assessed value, planned accumulated SAIFI limit, and unplanned SAIFI limit;	Clause 1.10.2	Section 8.5
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 1.1
planned interruptions cancelled without notice;	Clause 1.11.2	Section 1.1
planned interruptions for which Aurora gave additional notice;	Clause 1.11.3	Section 1.1
planned interruptions for which Aurora did not give additional notice;	Clause 1.11.4	Section 1.1
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 1.1
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 1.1
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

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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)	
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	

Determination Requirement	Attachment C of the Determination Reference	Statement Reference
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 2023

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 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023)

Aurora Energy Limited (the company) is required to disclose certain information in an Annual Delivery Report under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (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, Julian Tan, 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 2023 (the audited Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information in the Annual Delivery Report for the 2023 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 C of the Determination.

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 9 June 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information disclosed in terms of clauses 1.8 and 1.10 in Attachment C of the Determination, must take into account any issues arising out of the company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

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 Standard on Assurance Engagements 3100 (Revised) Compliance Engagements (SAE 3100 (Revised)), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

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 C 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 $55 million and operating expenditure totalled $48 million. The overall total amount of expenditure is significant relative to the company's total asset value of $736 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	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.

Key assurance matter	How our procedures addressed the key assurance matter
operational in nature and meets the definitions set out in the Determination.	Having completed these procedures, we have no matters to report.
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. The Commerce Commission has issued an exemption notice which excludes the assurance report from coverage of the information in the Annual Delivery Report for any issues arising out of the company's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. The company is required to comply with the condition of the exemption, including making the necessary disclosures in the Annual Delivery Report.	We obtained an understanding of the company's system to record electricity outages, and their duration. This included a review of the company's definition of interruptions, planned interruptions and major event days. The procedures we carried out to assess the adequacy of the company's methods to identify and record electricity outages and their duration included: • 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 such as Board minutes and media reports on interruptions to supply to gain assurance that interruptions to supply were recorded; • 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 and reported in accordance with the Determination, and the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination) including the SAIDI and SAIFI ratios in respect of each of the company's pricing regions; • obtaining explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. With respect to the exemption, we: • obtained and documented our understanding of the company's methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the company followed in the previous year; and • identified potential incidences of successive interruptions of supply to ensure that the

Key assurance matter	How our procedures addressed the key assurance matter
	company's methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years. Having carried out these procedures, and assessed the likelihood of reported electricity outages and their duration being materially misstated in the audited 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 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 on 30 March 2022.

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, 12 to 48, 66 (Section 8.4) and 69 to 80 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.

Julian Tan

Julian Tan
Audit New Zealand
On behalf of the Auditor-General
Dunedin, New Zealand
30 August 2023

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ENERGY