

31 March 2026

ASSET MANAGEMENT PLAN UPDATE

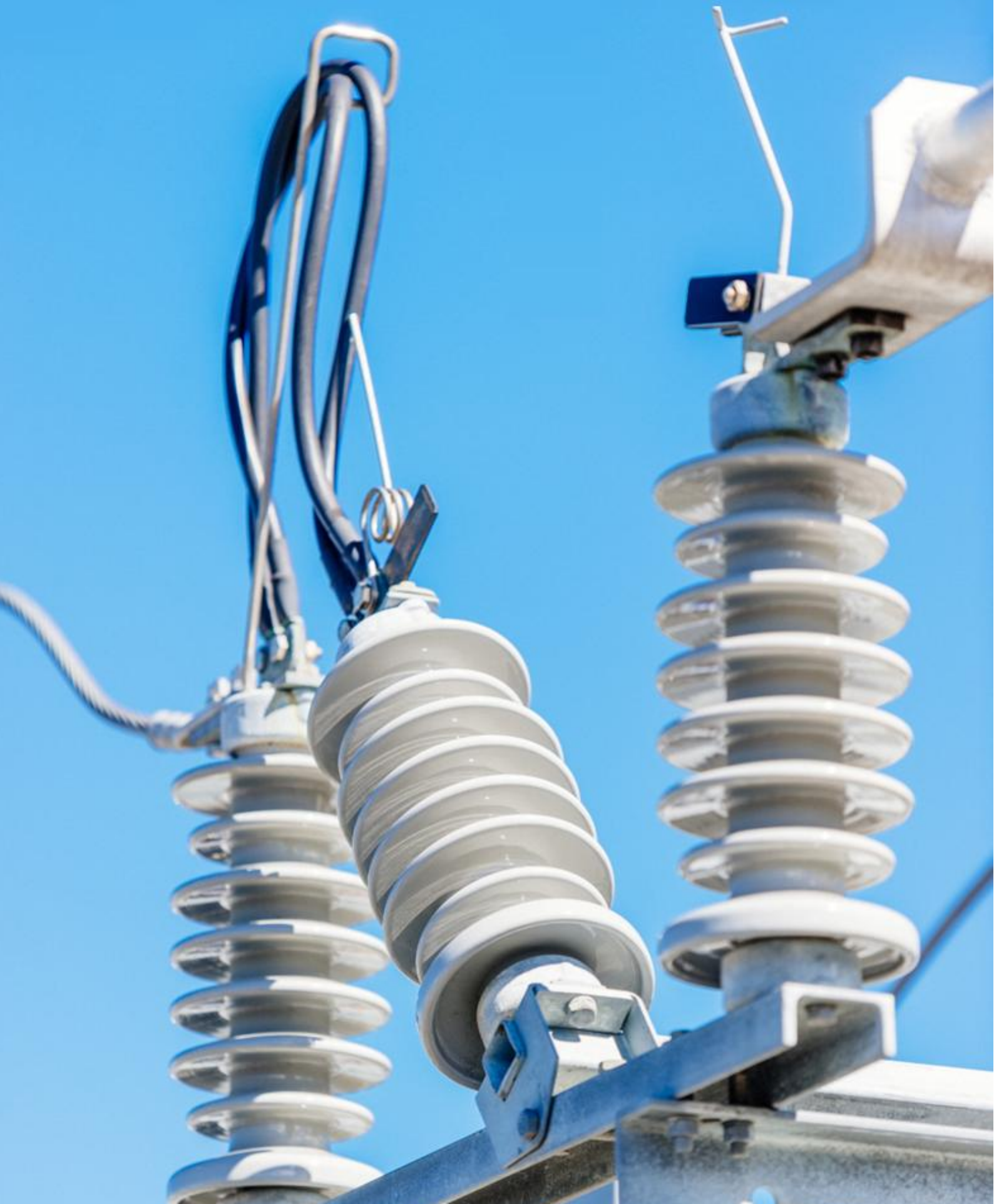
APRIL 2026 – MARCH 2036

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1 Introduction



Introduction

1.1 Introduction to this AMP Update

Aurora Energy Limited is a regulated Electricity Distribution Business (EDB). We take electricity from Transpower's national grid to power your home, business and the wider community, delivering a safe, reliable and sustainable electricity supply to more than 200,000 people across Ōtepoti Dunedin, Central Otago & Wānaka, and Tāhuna Queenstown. Our principal regulators are the Commerce Commission and the Electricity Authority.

This Asset Management Plan update builds on and provides a summary of updates from our Asset Management Plan published in March 2025 (AMP25). As well as publishing key reports informed by our updated 10-year plan, we also provide an update with respect to material changes from AMP25.

1.2 Purpose

The purpose of this document is to communicate material changes that have an impact on our progress and planning for the next 10-year period, and to ensure we meet disclosure requirements pursuant to clause 2.6.5 of the Electricity Distribution Information Disclosure Determination 2012, as amended (the *ID Determination*)¹.

This update captures only key or material progress and change since publication of AMP25. As such, this document should be read in conjunction with AMP25.

Our 2026 AMP update covers a 10-year planning period from 1 April 2026 (marking the commencement of the 2027 regulatory year (RY27)) to 31 March 2036.

The forecasting, which includes estimates for the procurement of internationally sourced equipment, was undertaken in late 2025, in

preparation for publishing the AMP update in early 2026.

The AMP26 Forecast was therefore prepared prior to the current global economic issues, which are expected to impact some input costs during RY27. This will be kept under review as we progress through the year, including any implications for the work programme.

1.3 Information disclosure requirements

On 6 August 2025 the Commerce Commission (the Commission) granted Aurora Energy an exemption² allowing us to disclose an AMP update rather than a full AMP, by 1 April 2026. Clause 2.6.5 of the ID Determination states that the AMP update must:

- Relate to the electricity distribution services supplied by the electricity distribution business (EDB).
- Identify any material changes to the network development plans disclosed in the last AMP (or AMP Update) under clause 11 and clause 17.5–17.7 of Attachment A.
- Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP (or AMP Update) under clause 12 of Attachment A.
- Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b.
- Identify any changes to the asset management practices of the EDB that would affect Schedule 13 Report on Asset Management Maturity disclosure.

¹ The latest amendment determination can be found on the Commission's website at [Current information disclosure requirements for electricity distributors | Commerce Commission](#).

² A copy of the exemption letter can be found on the Commission's website at [Exemptions to information disclosure requirements | Commerce Commission](#).

Introduction

In addition, clause 2.6.6 requires each EDB to publicly disclose the following reports before the start of each disclosure year:

- The Report on Forecast Capital Expenditure in Schedule 11a.
- The Report on Forecast Operational Expenditure in Schedule 11b.
- The Report on Asset Condition in Schedule 12a.
- The Report on Forecast Capacity in Schedule 12b.
- The Report on Forecast Network Demand in Schedule 12c.
- The Report on Forecast Interruptions and Duration in Schedule 12d. If an EDB has sub-networks, it must also complete the Report on Forecast Interruptions and Duration set out in Schedule 12d for each sub-network.
- The Mandatory Explanatory Notes on Forecast Information in Schedule 14a.

EDBs are also required to -

- publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by two directors of the EDB; and
- provide the Report on Forecast Cybersecurity Expenditure in Schedule 11c to the Commission.

1.4 Document structure

To clearly articulate the key themes and priorities for Aurora Energy during this regulatory year as we transition from a customised price-quality path (CPP) to a default price-quality path (DPP4), while also meeting the disclosure requirements set out in Appendix B, we have organised this AMP update into the following eight sections:

- **1: Introduction**
This section gives an overview of this AMP update and how we've organised the document in order to meet the regulatory requirements.
- **2: Context & Strategy**
This section provides the context in which

Aurora Energy operates. It details our strategic approach, our four strategic focus areas, and how we are approaching the transition from the CPP into DPP4.

- **3: Asset Management Practices – Material Changes**
This section describes the material changes to our asset management practices since our previous AMP. It describes our approach to forecasting and gives an overview of the strategic decisions and initiatives we have implemented based on those forecasts.
- **4: Asset Lifecycle Management – Material Changes**
This section discusses material changes we've made to the way we maintain our asset fleets based on our strategies, with a focus on our maintenance and renewal programmes.
- **5: Network Performance**
This section examines the performance of our networks, describing our reliability and regulatory compliance, along with commentary on recent unplanned outages. It also describes our improvement initiatives and our projected performance in relation to the quality standards we will be subject to under DPP4.
- **6: Network Development Plan – Material Changes**
This section outlines our approach to network development, focusing on material changes to our plan since AMP25, including our Upper Clutha and Queenstown capacity upgrade projects, prioritisation and reprioritisation of zone substation projects, and initiatives to develop non-network solutions to meet growing demand.
- **7: Forecast Expenditure – Material Changes**
This section provides a summary of our projected investment for the next 10 years and details the material changes to our forecast expenditure since our previous AMP.
- **8: Appendices**
Appendix A: Disclosure Schedules
Appendix B: Disclosure Requirements
Appendix C: Director's Certificate

2 Context and Strategy



Context and Strategy

2.1 Business strategy

Since we published AMP25 we have further developed our business strategy. The following sections outline the evolving context in which we are operating and set out the strategic drivers we have developed in response.

2.2 Operating context and future focus

Our industry is changing and we are transitioning into a future where customer expectations, regulatory settings and technologies change at pace. As we move beyond our CPP period and into DPP4, we must operate in a changing environment where social licence expectations are rising, digital capability is becoming fundamental, and competition for talent will continue to intensify. This requires us to not only respond to external factors that make planning a challenge but to proactively shape how our organisation adapts, ensuring we remain safe, reliable and resilient, while continuing to deliver value for customers and communities.

2.3 Our strategic drivers

In response to the challenges outlined above, and as set out in AMP25, this AMP26 update introduces four strategic drivers that will enable a transition to an intelligent network and position us well for the future. These drivers build on the foundation established through the CPP period and will support and

set the direction for our transition out of CPP and into DPP4 over the next three years.

2.3.1 Driver 1: Distribution system operator (DSO) and intelligent network foundations

Transitioning from a traditional network to an intelligent one, where we can integrate distributed energy resources (DER) and take an active role in managing a flexible, efficient and sustainable electricity network.

2.3.2 Driver 2: Future operating model

Learning how we need to adapt our future operating model and refining how our people, processes and technology align to ensure more efficient outcomes for our organisation, the broader industry, and our communities.

2.3.3 Driver 3: Strategic partnerships

Collaborating and cooperating with strategic partners to share knowledge and work together to unlock value and mitigate risk by leveraging shared scale, expertise, and resources.

2.3.4 Driver 4: Efficient and future-focused core

Optimising our core business processes to ensure they are efficient and future focused. These are crucial to assist our strategic capacity upgrades, for instance in the fast-growing Upper Clutha/Wānaka and Queenstown regions.

STRATEGIC FRAMEWORK

ENABLING THE ENERGY FUTURE OF OUR COMMUNITIES

OUR STRATEGIC DRIVERS



OUR STRATEGIC FOCUS AREAS



OUR VALUES



SAFETY FIRST

Safety first means people come first!



SOLUTIONS FOCUSED

We step up, and own it!



ONE TEAM

We're better together!



LEARNING & INNOVATION

We love light bulb moments!



INTEGRITY

We do the right thing!

Context and Strategy

2.3.5 Transition from CPP to DPP4

The end of the RY26 regulatory year (31 March 2026) marks the conclusion of our CPP period (April 2021 to March 2026) and our transition onto DPP4.

On 25 November 2025, the Commerce Commission published its final decision on Aurora Energy's transition to the 2025–2030 default price-quality path, the *Final Decision Reasons Paper*.

The key decisions with regard to network expenditure allowances were as follows:

- The expenditure forecasts for Asset Replacement and Renewals set out in AMP25 were fully approved.
- Network Growth expenditure was approved with the exception of Stage 4 of the Upper Clutha Network Development project.
- Other expenditure categories including Customer-Initiated Works (CIW) and Reliability, Safety & Environment were fully approved.
- Our corrective maintenance allowance was treated in isolation and approved at a reduced level of expenditure.

3 Asset Management Practices – *Material Changes*



Asset Management Practices – Material Changes

3.1 Asset Management Maturity Assessment

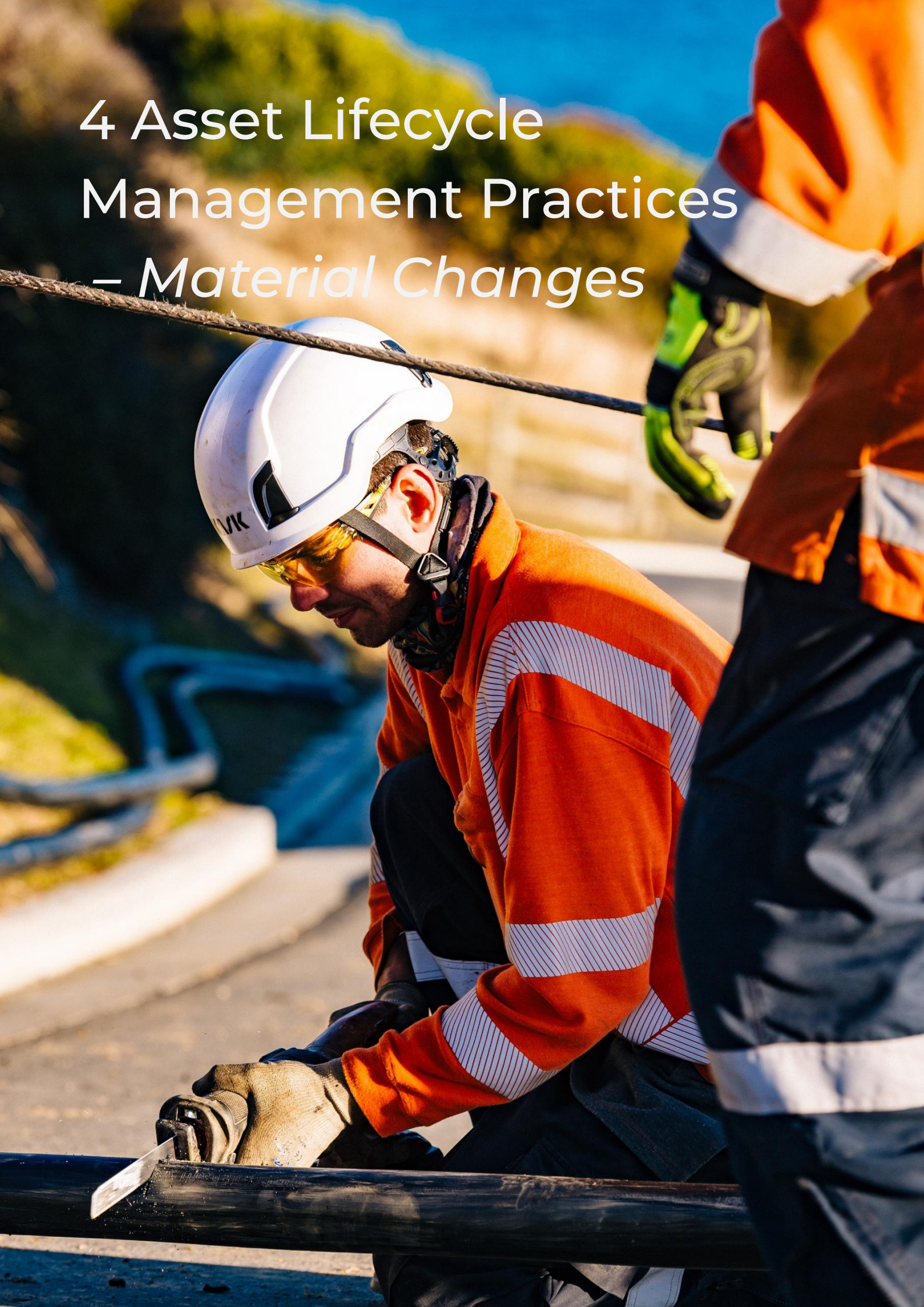
Our commitment to ongoing advancement of Asset Management practices, coupled with a focus on building strategic partnerships, sets us up to ensure we can minimise the future financial impact of heightened investment levels on consumers, while navigating the Energy Transition.

While multiple asset management improvement initiatives are currently in train, we are not reporting material changes to our Asset Management Maturity Assessment score as per the Asset Management Maturity Assessment Tool (AMMAT).

We will again report progress against our Development Plan in this year's RY26 Annual Delivery Report (ADR).

We anticipate that at the conclusion of the CPP reporting period, it will be appropriate to review and re-cast our Asset Management Improvement Plan (our ongoing programme of asset management improvement initiatives), to ensure it positions us to build on the progress made against our CPP 2021 Development Plan, while also ensuring it is relevant to current and emerging priorities and aligned to current best practice in the sector.

4 Asset Lifecycle Management Practices – *Material Changes*



4.1 Asset lifecycle management practices

We have ongoing programmes in place to continually mature our asset lifecycle management practices. Our aim is to ensure a safe and reliable network whilst optimising our investment in the assets.

We have a number of initiatives underway and will provide a further update on progress in our RY26 ADR; but as of this update, asset lifecycle management practices or changes in the last regulatory year include:

- The rollout of a new inspection standard for switchgear
- The publication of an asset failure and vegetation root cause analysis (RCA) standard
- The publication of a conductor testing standard and commencement of a programme of conductor testing to validate the correlation between age and loss of strength for targeted conductor types

Having the RCA process embedded alongside new inspection standards which have been rolled out over the past three years (for overhead, distribution transformers, distribution switchgear and LV enclosures) is allowing us to proactively identify and address significantly more corrective tasks.

While this will enable us to better prevent failures and faults, which should flow through to improved performance trends, it is putting upward pressure on our opex forecast.

The following sections provide fleet-specific context on material changes and provide context for Schedule 12a – Asset Condition Report.

4.1.1 Poles

We have updated our asset health profile to reflect the rollout of our new Overhead Inspection Standard. As stated in our previous two AMPs, we will not have a full condition-based health assessment for all the fleet until the first five-year cycle has been completed.

As such, we expect to make year-to-year adjustments to the health profile.

We have also progressed trials on pole testing methods and expect that emerging work will further enhance our ability to optimise our investment while ensuring risks are effectively managed.

4.1.2 Conductor – SWER

The majority of our single wire earth return (SWER) conductor has now been upgraded from single-phase to two-phase, requiring full conductor replacement. At the time of preparing this update, commissioning of the final upgrade project as indicated in AMP25 had not yet been completed.

4.1.3 Cables

As described in Section 11.5 of AMP25, we recognise that there are inconsistencies between the predominantly age-based AHI profile as shown in Schedule 12a and the planned investment for subtransmission cables, which is informed by known condition and fault information. We plan to enhance the model so that it better reflects the probability of failure and is therefore better aligned to identified investment needs.

It should also be noted that we are now treating submarine cable—which we previously included with all other types of cable—as a stand-alone asset class in Schedule 12a.

4.1.4 Zone substations

Adjustments to our renewal plan have been informed by our current view of asset health, alongside reprioritisation and coordination of the wider programme of work.

Reprioritisation includes bringing forward the replacement of the Fernhill zone substation 11 kV switchboard in favour of the Kaikorai Valley zone substation switchgear renewal, which has been deferred by four years.

Asset Lifecycle Management Practices – Material Changes

4.1.5 Secondary systems – Protection

Work on the Protection Fleet Strategy in the last year has included benchmarking against other networks and internal analysis of our fleet's performance. Both initiatives support a revision to the expected life of certain protection assets. This adjustment is supported by improved failure data and risk quantification frameworks, providing confidence in asset condition and reliability.

A renewal strategy review, coupled with this adjustment, has resulted in a small increase in the average age of assets at their planned renewal date and a fleet risk profile that better reflects actual performance and condition. As above, this work enhances our ability to optimise our investment, while ensuring risks are effectively managed.

5 Network Performance



Network Performance

5.1 Unplanned outage performance update

New Zealand has experienced a number of significant weather events across the country in RY26, which have impacted on electricity supply. The Aurora network has been no exception, particularly in Dunedin, where our network experienced a multi-day major weather event and sustained customer interruptions. Our Queenstown and Central networks have also been impacted by persistent winds.

Across the network we have experienced a significant rise in the number of unplanned outages caused by vegetation. To date, vegetation is the primary cause for both unplanned SAIDI and unplanned SAIFI³.

We review all vegetation faults on our high voltage network and have identified that the predominant issue for RY26 has been out-of-zone trees, including broken branches and debris being blown into lines by strong winds.

Our analysis of these emerging trends is allowing us to better target improvement opportunities and make more informed decisions. We have already commenced a focused review and response to the performance observed in RY26.

The impact of the October major weather event

On 23 October 2025, parts of the lower South Island experienced gale force winds, which resulted in damage to trees and powerlines and impacted supply to more than 16,000 Aurora Energy customers, mainly in the Dunedin area. Most of these faults were caused by out-of-zone vegetation.

Due to the volume of faults and the work required to clear trees and repair lines during this event, some customers were affected for over 24 hours. This major weather event resulted in more than 100⁴ SAIDI minutes for the period from 23 to 25 October.

The Dunedin network typically experiences less than 30 SAIDI minutes annually.

In the aftermath of the weather event, our network continued to experience a greater frequency of vegetation faults for several months. We believe the increased frequency and impact of vegetation faults in November and into December was a delayed impact of the damage to or weakening of trees during the 23 October storm.

5.1.1 Regulatory compliance

From a compliance perspective, our reliability performance for RY26 is forecast to remain within the limits for unplanned SAIDI and SAIFI.

While the trends in the first half of RY26 were similar to the previous year's trends for the same period, the October storm event and the November to December period materially shifted our position.

5.1.2 DPP4 quality standards

From RY27 Aurora Energy will transition into a new set of quality standards for the DPP4 period.

The target and limit for unplanned SAIDI will increase under DPP4, as will the boundary threshold for a major event day normalisation. Our experience in RY26 indicates that this threshold adjustment may have more impact on future DPP4 performance results than previously anticipated.

The threshold change has the potential to amplify the SAIDI impact of days of multiple faults driven by factors such as high wind events which cause damage to out-of-zone vegetation—events we have now observed repeatedly across the October to December period this year.

³ This statement relates to raw, un-normalized performance.

⁴ The figures in this example have been calculated at the Aurora network level.

Network Performance

We intend to continue to monitor this impact before considering the need to adjust the modelling approach used to populate Schedule 12d: Report Forecast Interruptions and Duration in a future update.

In addition, the combination of the change to the major event day threshold, as well as an increased impact from wind, may make a comparison of CPP vs DDP4 SAIDI trending misleading.

6 Network Development Plan – *Material Changes*



6.1 Overview of our network development plan

In AMP25 we reported that Aurora Energy, Transpower, Queenstown Lakes District Council and other stakeholders had produced an extended demand forecast to the year 2050 for Upper Clutha and Queenstown. The forecast showed clear indications that growth will continue to 2050, and we have processes in place to keep the forecast under review. At the time of this AMP update, we have revisited our network development plans, described in Section 6.2 below, to incorporate new material information.

The 2025 implementation of new LV visibility tools enhanced our confidence in our ability to monitor the impact of distributed generation on our LV network. This has enabled us to proactively increase the export limit for single phase consumer distributed generation to 10 kW. We are monitoring the effects of this change but we believe the impact at this stage is manageable and that the vast majority of connections will not face any network constraint at this time.

The increased export limit has positive outcomes for consumers and supports the uptake of consumer energy resources (CER), which is an integral part of enabling a future network that responds to customers' changing preferences.

6.2 Material changes to our plan

The strong growth in demand in our Queenstown and Upper Clutha networks is creating an environment in which our plans are continually evolving so that we can respond to customers' needs whilst keeping an eye on efficiency, affordability and network security.

6.2.1 Upper Clutha capacity upgrade

In 2025 we set out the details of our five-staged approach to addressing capacity in the Upper Clutha region. This included Transpower's construction of a new Tarras GXP to support the current and future economic growth of the Upper Clutha region.

Our strategic approach is to maintain a flexible development program that will move forward to the next stage when it is needed. The approach includes leveraging distributed energy resources (DER) and flexible demand where possible, with the aim of identifying any feasible opportunities to defer investment. The staged investment approach provides the opportunity to respond to step changes in demand as needed and enables us to flex our plan according to any new material information, including demand growth, non-network solutions, and electrification. This is the same approach as we are applying in the Queenstown capacity upgrade.

As outlined in Section 2.3.5 above, the Commission's final decision with respect to DPP4 period expenditure excluded the planned Stage 4 of the Upper Clutha capacity upgrade project. While we continue to pursue non-network solutions and test opportunities to defer stages of this investment, we need to plan to meet the scale of growth as forecast, given what we know now.

Our forecast total cost is unchanged; however, the profile of when costs will be incurred has been updated to reflect new information on the timing of a large point load which is currently at an active planning stage.

6.2.2 Queenstown capacity upgrade

As set out on the Energising Queenstown website, from July to September 2025, Transpower, Aurora Energy and PowerNet ran a public consultation seeking feedback on four short-listed future transmission line options. This was preceded by three years of collaboration with Queenstown Lakes District Council (QLDC) and other external stakeholders on how the future electricity demand and infrastructure would shape up, and takes into account the region's unique landscape, electrification, and the leveraging of distributed energy resources (DER).

Network Development Plan – Material Changes

The four proposed options are:

- **Option 1:** New Arrow Junction GXP with single 110 kV circuit
- **Option 2:** New Arrow Junction GXP with double 110 kV circuit
- **Option 3:** New Arrow Junction GXP with double 110 kV circuit (assets built to 220 kV)
- **Option 4:** New Jacks Point GXP with double 110 kV circuit

The submissions and feedback received highlight the importance of community input, with the community broadly supporting Option 2, reflecting their need for an appropriate balance of investment in resilience, affordability, and sustainability. Some submitters advocated for a hybrid approach that combines accelerated DER uptake, demand management, and staged investments to defer capital expenditure while enhancing local resilience. This resonates with our strategic approach. Details of the public consultation and outcome can be viewed at www.energisingQueenstown.co.nz.

Based on the broad support for Option 2, we have worked through the network development process to include budget (2031–34) for subtransmission investment in this year’s AMP update to deliver the capacity from the transmission lines to businesses and homes in the Queenstown region.

6.2.3 Long-term planning integration for Queenstown sub-transmission

Our approach to the Queenstown sub-transmission upgrade is being informed by a broader, long-term planning lens that integrates network and non-network solutions. As part of the Energising Queenstown programme, we will continue to review demand, timing and solution pathways through the Demand Forecast Working Group to ensure our investment decisions remain robust and adaptive to emerging trends. This work will be captured within our Integrated Regional Development

Plan and explicitly considers the role of distribution energy resources, including solar and battery storage, alongside demand side management opportunities. This programme of work has been initiated to ensure all credible options are assessed to meet the region’s long-term capacity requirements, and to avoid premature or inefficient network investment. In parallel, we are actively engaging with market participants to improve our understanding of the economics and operational feasibility of both behind-the-meter and utility-scale DER solutions, and how these could be integrated into a least cost whole-of-system outcome for Queenstown.

6.2.4 Flexibility solutions for Upper Clutha and Queenstown

In May 2025, we commenced an Open Call for flexibility solutions with an expression of interest (EOI) process for flexibility service providers in both regions. Following a robust evaluation process that included meeting with the first tranche of EOI respondents, we have now commenced the procurement process with the flexibility service providers that we have identified as suitable. After assessing the proposals, we will move to the final stage of signing agreements with the successful providers. We plan to continue this process, with the aim of maximising capacity support.

6.2.5 Queensberry Hills and Lindis Crossing zone substations

We are constructing a new zone substation at Queensberry Hills as part of one of the stages to enable the Upper Clutha capacity upgrade programme. Initially configured as a 66 kV switching station with allowance for two transformers, this substation will enable us to retire the existing space-constrained Queensberry zone substation. The timing of this project has been staged and extended compared to AMP25, to optimise delivery of capacity for alignment with current expectations regarding network risks and growth forecasts.

Network Development Plan – Material Changes

6.2.6 Customer-initiated works

We are aware of two potential—albeit substantial—customer-driven projects in the Queenstown region that would require significant additional investment should they proceed. However, owing to the high level of uncertainty associated with the proposed developments at the time of preparing this AMP, these projects are listed as residential developments in the table of Major projects excluded from expenditure forecasts (Table 7-3).

Our customer-initiated works forecasts have an element of inherent uncertainty. Queenstown developments are particularly uncertain as a result of the unique competition for network connections that has been allowed to develop in the region.

6.2.7 Growth – Malaghans/Whitechapel reprioritisation

Strong development continues in the Queenstown distribution region, particularly to the south and east of Arrowtown and Frankton. We have adjusted our capital investment programme to prioritise areas where development is most active, while ensuring we remain on track to meet our long-term asset replacement needs.

To serve developments in the Arrow Junction and Morven Ferry corridor, we are now prioritising construction of the Whitechapel (new Arrowtown) zone substation over the Malaghans (new Dalefield) zone substation. This reprioritisation will enable work to commence on the Whitechapel substation during RY27.

Growth in the Dalefield area is expected to be steady, and both the Whitechapel and Malaghans substations will be required in the medium term to replace ageing assets and meet ongoing growth. Therefore, we will continue developing the Malaghans substation design to ensure we are ready to respond to new load requests.

In a challenging property market, securing the site early provides certainty for future delivery; and progressing the Malaghans and Whitechapel designs in parallel creates cost efficiencies due to their similar design requirements. However, by reprioritising the order of delivery of these projects in response to the latest demand forecasts and customer connection expectations, we can defer some investment by a number of years and reduce the overall 11 kV development requirements to offload the existing Arrowtown zone substation.

6.2.8 Growth – Luggate zone substation

In AMP25, we identified the Luggate zone substation as a growth-driven investment for the Upper Clutha region. Since then, the location of anticipated growth has shifted. Accordingly, we have prioritised upgrades at the Riverbank and Queensberry substations to provide the required capacity in the medium term.

Camp Hill also retains spare capacity and is expected to receive reinforcement when the new TAR-CH 66 kV line is commissioned as part of the Upper Clutha development programme. We have therefore deferred the Luggate zone substation beyond the current planning horizon and will reconsider it when demand patterns justify additional capacity.

6.2.9 Summary of key changes to the growth programme

Table 6-1 summarises recent changes to the growth programme. Further to what has been described previously, the table also includes 11 kV works projects (which are typically reactive and planned on shorter investment horizons), where we have opportunistically coordinated with other infrastructure providers to deliver capacity cost-effectively, and projects where we are upgrading end-of-life assets instead of carrying out like-for-like replacement, to provide additional capacity for growth at a relatively small marginal cost.

Network Development Plan – Material Changes

Table 6-1: Changes to the growth programme

Project name	Change vs AMP25	Need date	Total cost (\$m)	Rationale
New Camp Hill Express Feeder (CH2010)	New	2026	1.5	Coordinated with QLDC wastewater works for cost synergies. Delivers improved security and capacity to Hawea versus the previously planned conductor upgrade and recloser.
Riverbank to Luggate New Cable Stage 1	New	2027	1.3	Strategic project to enable future development to be completed in coordination with QLDC wastewater project (cost synergies).
Kawarau Falls Bridge to Jacks Point Interconnection	New	2028	1.1	Improving security of supply and providing for growth in the Jacks Point area.
Willowbank 33 kV Switchgear	New	2028	1.5	Replacing end-of-life assets with a larger installation to increase capacity.
Parkburn Substation Feeders	Advanced four years	2030	1.8	Brought forward to provide for development in the Parkburn and Pisa Moorings areas.
Lake Hayes Subtransmission Cable Upgrade	Advanced three years	2031	1.3	Brought forward to align with the Morven Ferry distribution project.
North City 33 kV Switchgear and Cut Into SS-WB cable	New	2031	1.9	Replacing end-of-life assets with a larger installation to increase capacity.
Convert Berwick area (Dunedin) to 11 kV	Advanced three years	2032	3.8	Improving power quality and increasing capacity.
South Dunedin to Ward Street Cables and 33 kV Switchgear	New	2032	8.5	Replacing end-of-life assets with a larger installation to increase capacity.
Luggate Zone Substation	On hold	N/A	N/A	The location of anticipated growth has shifted, so other investments have been prioritised.
Malaghans Zone Substation	Defer 3 years	2033	13	Prioritising according to expected developments
Malaghans Distribution Network		2034	9.8	11kV development to transfer load to new zone substation
Whitechapel (new Arrowtown) Zone Substation	Advance	2030	11.3	Prioritising according to expected developments
Whitechapel Distribution Network	Advance	2031	8	11kV development to transfer load to new zone substation
Queensberry Hills Zone Substation	Partial deferral	2033	9	The 66 kV switching station will continue but the zone transformers have been deferred contingent on load growth.
Remarkables Zone Substation	Defer one year	2031	6.2	The timing of this project needs to be coordinated with customer requirements. Currently anticipated in 2031.

7 Expenditure – *Material Changes*



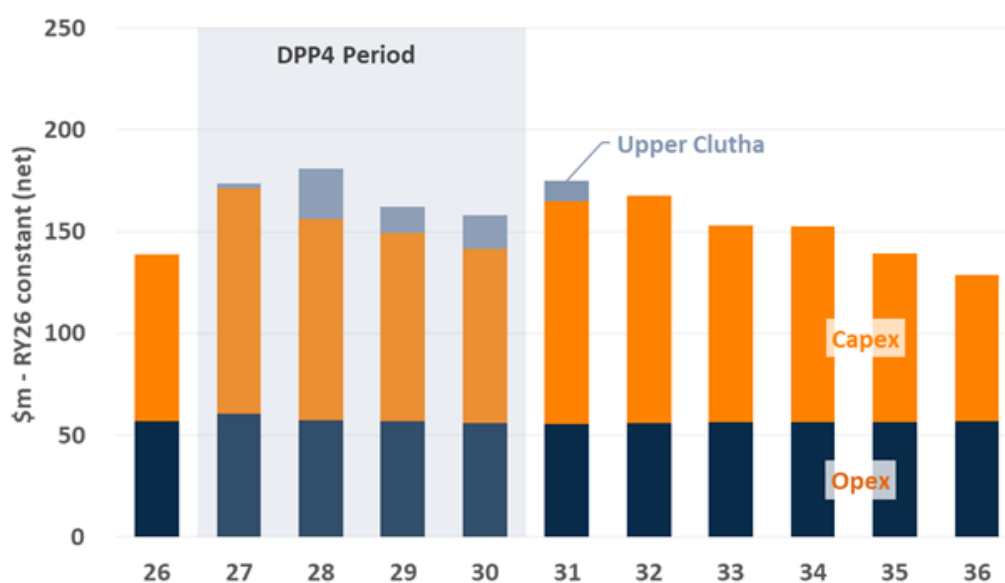
Expenditure

7.1 Expenditure overview

In this section, we provide an overview of capital and operational expenditure forecasts for the period RY27–RY36, with a focus on material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.

This AMP update is informed by our AMP25 plan but has been updated to capture newly available information. All financial values are expressed in \$RY26 constant price New Zealand dollars (millions). Figure 7-1 provides a summary of total forecast expenditure for both the current RY26 period and the forecast RY27–RY36 planning period. Total expenditure for the 10-year period from RY27 to RY36 is \$1.59 billion (net).

Figure 7-1: Forecast expenditure for RY27 to RY36 and current year in constant prices



7.2 Capex – Material changes

Table 7-1 shows the total forecast expenditure for both the current RY26 period and the forecast RY27–RY36 planning period.

Table 7-2 and Figure 7-2 on the following page show the variance in forecast capex (Schedule 11a) from our AMP25. Our current capex forecast plans an additional \$23 million from AMP25 levels over the 10-year comparison period RY26–35.

Table 7-1: 10-year capex forecast, Total in constant prices

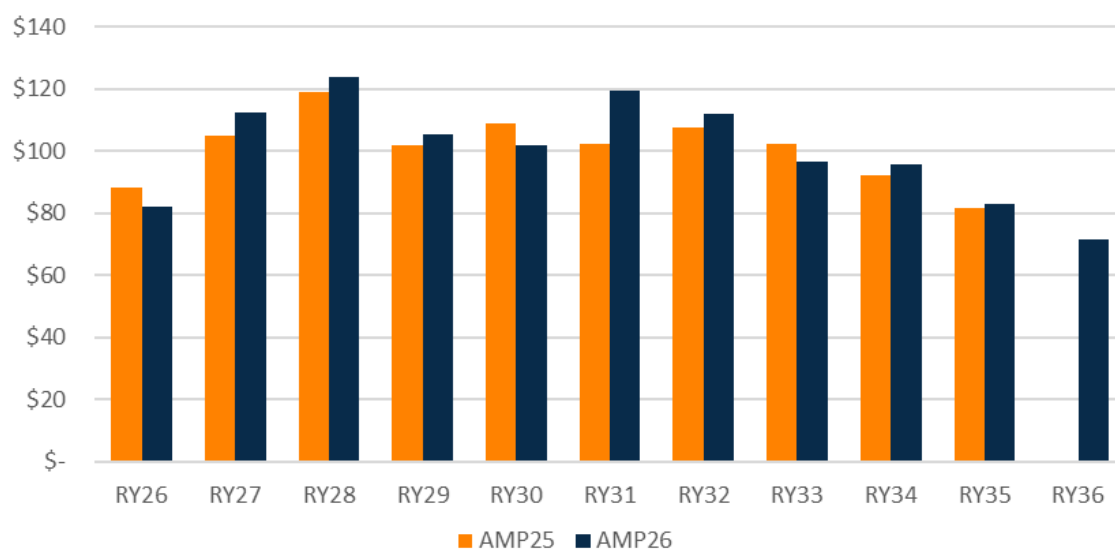
AMP26	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
Asset renewal	57.1	60.6	62.7	58.8	52.9	55.6	63.4	54.9	52.7	50.1	45.9
Network growth	9.1	21.9	41.5	27.7	30.2	44.7	30.5	24.4	25.0	16.0	7.8
Network upgrade	1.9	3.4	5.1	3.6	3.3	3.9	3.4	2.9	2.9	2.9	2.9
Customer initiated	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Non-network capex	2.6	15.5	3.3	4.0	4.4	4.0	3.3	3.0	3.9	2.7	3.8
Totals	82.0	112.7	123.9	105.4	102.1	119.4	111.9	96.6	95.9	83.0	71.7

Expenditure

Table 7-2: Capex variance AMP25–AMP26 10-year comparison in constant prices (RY26–35)

Variance	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	TOTAL
Asset renewal	2.4	1.8	0.6	-1.3	-2.3	3.9	-1.6	-4.1	4.0	5.4	8.8
Network growth	-2.1	-6.6	4.3	5.5	-3.7	13.4	4.3	-1.7	-0.9	-3.2	9.3
Network upgrade	0.1	0.3	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
Customer initiated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-network capex	-6.5	12.3	-1.0	-0.9	-0.7	-0.4	1.3	-0.2	0.3	-0.8	3.4
Totals	-6.2	7.8	5.0	3.3	-6.7	16.9	4.1	-5.9	3.4	1.4	23.1

Figure 7-2: AMP25–AMP26 10-year total capex (net) comparison in constant prices (RY26–35)



7.2.1 RY26 outturn

The above reflects our year-end forecast as projected at the time of casting our 10-year plan. It reflects an overall underspend in RY26 capex, compared to our AMP25 plan.

Land acquisitions planned to be completed in RY26 have been delayed by prolonged negotiations. Multiple settlements will now be completed in RY27.

Following post-design constructability investigations for the Halfway Bush zone substation renewal project, it was determined that the intention to upgrade the existing building was not viable. This change introduced additional cost and impacted on the project and programme plan.

The forecast expenditure for some major projects has been refined following

completion of the tender process, resulting in a reduction in RY26 expenditure. This adjustment reflects improved cost certainty and the outcome of a successful competitive tendering process.

A recent update on the Fernhill distribution reconfiguration indicates that completion will now occur in RY27, resulting in an underspend of planned expenditure in RY26.

In our non-network capex plan, we previously allowed for office facility upgrades and new right-of-use asset arrangements to be entered during RY26. Owing to an extended period of options analysis and due diligence, those investments and related lease arrangements were deferred and are now forecast to be established in RY27.

Expenditure

7.2.2 Material changes to our 10-year network capex forecast

During this regulatory year, we have flexed our plan and reprioritised projects as required, based on the latest available condition data, emerging insights from inspection programmes, refinements to project scopes, updated cost information, and the need to balance resource availability, risk, and delivery targets.

10-year network capex forecast update

Asset renewals: Overall renewals have increased over the 10-year forecast period but remain within the DPP4 allowance.

This uplift is being driven in part by higher expenditure on ground-mounted transformers. The forecast is informed by an assessment of incoming condition data from a new inspection standard and the identification of a sub-fleet with potential safety-in-design issues.

In addition, a deliberate strategy to commence informed investment in LV conductor, LV cables, and distribution cables in the latter half of our 10-year plan also contributes to the overall uplift.

Network growth: Our updated expenditure forecast for growth projects has introduced a peak investment in RY31. This is primarily driven by the reprioritisation of investment at Arrowtown—as noted in Section 6.2.7—and a change in forecast demand uptake for the Remarkables zone substation, leading to that investment being deferred by one year.

Other contributors include the newly scoped South Dunedin to Ward Street cables and 33 kV switchgear project planned for RY31. For an overview of changes to our growth program, refer to Table 6-1.

The Upper Clutha Capacity Upgrade remains in our plan, staged as per AMP25. The timing of investment reflects the most recently available information with respect to step changes in demand.

Network Resilience: As set out in AMP25, we identified the need to have critical spare power transformers of multiple specifications for resiliency preparedness and planning. When working through the detailed scenario analysis, it was identified that we could create a spare 10 MVA and a spare 24 MVA power transformer by upgrading a single site, including retrofitting an existing 7.5 MVA transformer to meet the 10 MVA specification requirements. This resulted in greater than forecast expenditure but significantly greater benefits from a resiliency improvement perspective.

Customer-initiated work: There is no material change from the level of expenditure indicated in AMP25.

7.2.3 Material changes to our 10-year non-network capex forecast

As outlined in Section 7.2.1 above, office facility upgrades previously forecast for RY26 are now forecast to be delivered in RY27. Our forecast pertaining to RY27 right-of-use asset additions has been updated accordingly. We have also updated our ICT forecasts to reflect our latest view of investment priorities and the need for core system upgrades from RY27 onwards. Our ICT investments aim to ensure our current and future technology systems can be utilised to drive customer service levels and enable critical functions and efficiencies across the business.

7.2.4 Excluded expenditure

The capital expenditure forecasts in this AMP update exclude a number of potential major upgrades that we do not consider reasonable to include in the expenditure projections at this stage, for the reasons set out in Table 7-3, below.

In AMP25, the Gibbston substation was listed as an excluded project due to uncertainty around its requirement. Following further planning, the preferred approach is to advance the construction of Whitechapel (New Arrowtown) zone substation. As a result, the Gibbston substation is no longer required and has been removed from the table below.

Expenditure

As discussed in the Network Development section, we have added to Table 7-3 two projects that would be customer-initiated works, should they go ahead. The proposed developments in Queenstown are both large-scale developments that would require significant investment during the DPP4 period and would potentially need further investment in the DPP5 period. At the time of developing our forecast, these developments had not obtained Fast-Track approval and therefore have been excluded from our base forecast.

There are a further two additional excluded projects identified in this AMP update: the Dunstan 33 kV bus, where the need originates from Transpower's asset condition rather than Aurora Energy's network plan; and the Fernhill sub-transmission upgrade, which is contingent on large developments in the area proceeding.

The cost estimate of major projects excluded from our expenditure forecasts in this update is \$92.7m, up from \$54.8m in AMP25⁵, and is representative of the high growth drivers in the Queenstown and Upper Clutha regions.

Table 7-3: Major projects excluded from expenditure forecasts

Excluded major projects	AMP26 high-level cost estimate (\$m)	Why we are not committing to the investment in this AMP update
New Bendigo Customer	0	Commercial arrangements for this new connection have yet to be agreed with the customer. Our current assumption is that the customer will fully fund the new connection.
Residential Development	TBC	Consumer-driven development is uncertain due to Fast-Track approval yet to be obtained, as well as the potential for the development to connect to a competitor's distribution network.
Residential Development	TBC	Consumer-driven development is uncertain due to Fast-Track approval yet to be obtained, as well as the potential for the development to connect to a competitor's distribution network.
Parkburn Zone Substation and Distribution Network	10.0	We are aware of early stage proposed residential subdivisions and commercial developments in the Mount Pisa area which have not reached sufficient certainty to justify including the investment in our plan. If the proposed developments are realised, the network will see a significant load increase exceeding the capacity of the existing single feeder from Cromwell.
Alexandra-Omakau Subtransmission Stage 1	3.3	The demand on the single subtransmission circuit, predominantly irrigation, has remained stable over the past six years. However, the addition of a 1 MVA load will exceed its thermal capacity. As it remains uncertain how this additional load might occur, we have not included this investment in the plan. We will continue to monitor the load and any new load applications to inform this investment.
Riverbank Second Transformer and 11 kV Feeder Stage 2	7.0	Forecasts indicate a sustained increase in load on the N security Riverbank zone substation. This potential demand growth was not included in our current plan due to uncertainty. If this growth materialises, an upgrade to an N-1 security level will be necessary to comply with our Security of Supply Guidelines.
New Queenstown 33 kV Supply	5.1	RY36-38, with a total cost of \$7.8m (\$5.1m in this planning period). Demand forecasts indicate that the peak demand of the N-1 Queenstown 33 kV subtransmission circuits will continue to grow, surpassing the circuit's firm capacity from the medium term onwards. However, because we lack certainty that this load growth will continue, we have excluded this investment from the plan.
Stevenson Rd Supply	4.5	We are aware of a significant development that would necessitate a substantial increase in load, which in turn would necessitate a new feeder. However, the timing is currently uncertain; and as such, the investment provision has not been included in the current plan.

⁵ Refer to Table 8-1 on page 103 of AMP25.

Expenditure

Excluded major projects	AMP26 high-level cost estimate (\$m)	Why we are not committing to the investment in this AMP update
New Whakatipu Zone Substation	2.0	RY36–38, with a total cost of \$16.4m (\$2m in this planning period). The prudent demand forecast for the Frankton zone substation suggests a need for the establishment of a new zone substation. However, due to uncertainty regarding the magnitude and timing of this growth, we have not included this investment in our current plan.
Dunstan 33 kV Bus to Retire Transpower 33 kV Bus at Clyde	5.0	The need originates from Transpower's asset condition rather than Aurora Energy's network plan, and will effectively transfer ownership of the 33 kV bus from Transpower to Aurora Energy.
Fernhill Subtransmission Upgrade	1.9	RY36–37, with a total cost of \$6.5m (\$1.9m in this planning period). Contingent on large developments in the area proceeding, this project provides for growth in the Fernhill area
Fernhill Substation Upgrade	5.4	Contingent on large developments in the area proceeding, this project provides for growth in the Fernhill area in combination with replacing end-of-life assets.
33 kV Interconnection from New GXP to Remarkables	5.2	RY31-33: The proposed interconnection would link the Arrow Jn GXP and Remarkables 33 kV networks, providing an alternative supply path for the southern Queenstown area and improving voltage and reliability. The cost-effectiveness of this option depends on the final sites and associated 33 kV routes. Until these are confirmed and economic analysis is complete, the project remains uncertain.
Jacks Point Zone Substation	5.2	Jacks Point zone substation was identified as a base project in AMP25 to relieve Frankton and support general load growth in the southern Queenstown area. Updated forecasts indicate that overall growth can be managed within existing and committed capacity within the current planning window. Localised development, such as Homestead Bay, could accelerate the need for this substation; however, the timing and certainty of that development are unclear.
Jacks Point Subtransmission Upgrade	5.3	This upgrade is directly linked to the Jacks Point zone substation and would provide the subtransmission capacity required to increase the capacity available at the new site. As with the substation, the need for this work is contingent on significant localised development.
Camphill 66 kV Power Transformer	5.8	The forecast for the N security Camp Hill zone substation indicates a continued increase in demand, necessitating an upgrade to the security level to comply with our security of supply guidelines. However, due to uncertainties around the projected growth, we have excluded this investment from the current plan.
Total	92.7	

7.3 Opex – Material changes

Our current operational expenditure plan, shown in Table 7-4, forecasts a decrease in spend by \$13.9m from AMP25 levels, over the 10-year comparison period RY26–35.

On the next page, Table 7-5 shows the opex forecast variance from the AMP25 forecast, while Figure 7-3 shows the variance between AMP25 and AMP26 and Figure 7-4 shows the variance by expenditure category.

Table 7-4: 10-year opex forecast, Total in constant prices

AMP26	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
Preventive Maintenance	5.6	7.9	7.8	7.9	7.4	7.4	7.4	7.5	7.5	7.6	7.6
Corrective Maintenance	7.6	5.7	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4
Reactive Maintenance	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8	3.9
Vegetation Management	4.4	4.7	5.1	5.0	4.5	4.7	4.7	4.8	4.8	4.8	5.4
SONS	20.0	20.9	20.2	20.3	20.4	20.2	20.4	20.7	20.7	20.3	20.2
Business Support	15.6	17.8	16.4	15.8	15.9	15.3	15.4	15.4	15.4	15.5	15.5
Totals	57.0	60.7	57.2	56.8	55.9	55.5	55.9	56.4	56.5	56.4	57.0

Expenditure

Table 7-5: Opex variance AMP25–AMP26 9-year comparison in constant prices (RY27–35)

Variance	RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	TOTAL
Preventive Maintenance	-1.0	0.5	-0.2	0.0	-0.8	-0.2	-0.3	-0.2	-0.3	-0.3	-2.7
Corrective Maintenance	0.0	1.6	-0.2	-0.2	-0.2	0.1	0.1	0.1	0.1	0.1	1.6
Reactive Maintenance	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-10.0
Vegetation Management	-0.1	-0.6	-0.3	-0.2	-0.6	-0.4	-0.4	-0.4	-0.4	-0.4	-3.7
SONS	0.3	0.7	0.1	0.1	0.1	0.1	-1.1	0.4	0.5	0.0	1.2
Business Support	-0.2	-0.8	0.1	0.2	0.4	0.0	0.0	0.0	0.0	0.0	-0.2
Totals	-2.0	0.4	-1.5	-1.2	-2.1	-1.4	-2.6	-1.0	-1.0	-1.5	-13.9

Figure 7-3: AMP 2026 vs AMP 2025 Total opex summary in constant prices

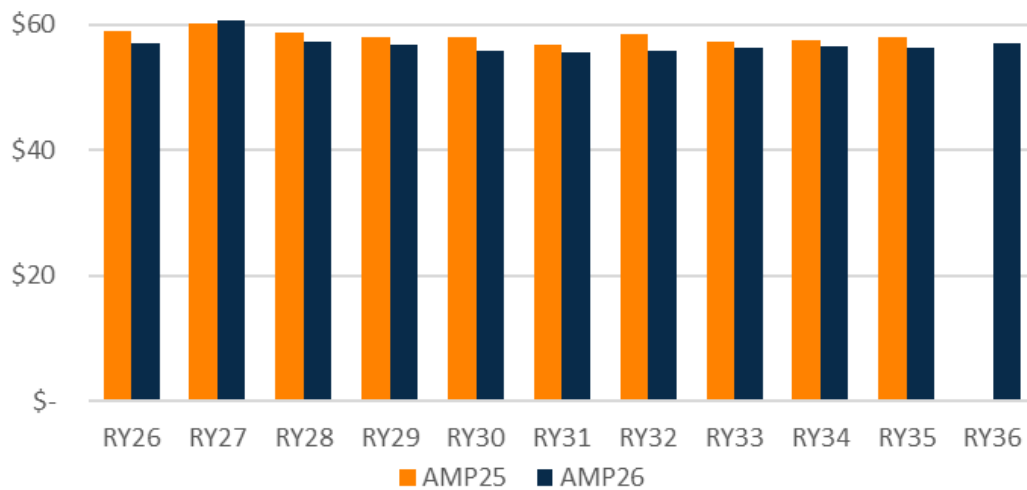
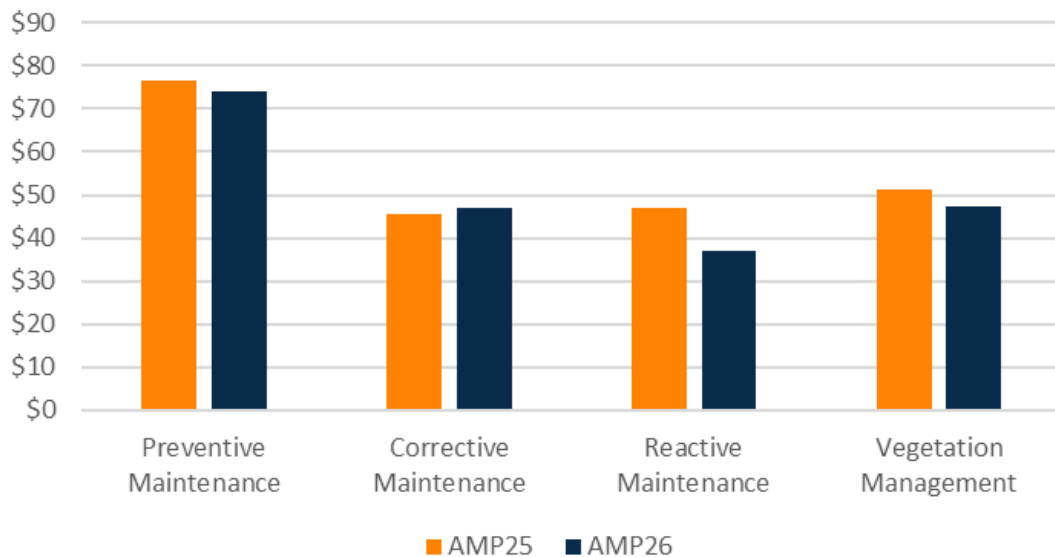


Figure 7-4: Opex variance by category AMP25–AMP26 in constant prices



Expenditure

7.3.1 Material changes to our current network opex 10-year forecast

We have adjusted our network opex for the DPP5 period to lower levels than what was signalled in AMP25.

As we enhance our adoption of unit rates and improve processes around prioritisation, we are forecasting reduced expenditure needs. We will continue to review the DPP5 expenditure levels throughout the DPP4 period.

Currently, we use a base-step-trend modelling approach for network opex forecasts. However, we are continuing to work towards a bottom-up forecast for preventive maintenance and planned corrective maintenance, including ongoing work with our field service providers to build on the standard unit rate library.

Some aspects of opex expenditure forecasts are inherently uncertain, particularly given the impact of increasing extreme weather events and changes due to improved processes to proactively identify preventive measures through our root cause analysis on asset failures. Standing up new inspection standards introduces the opportunity for us to proactively identify corrective maintenance that is difficult to quantify.

Since we completed our previous 10-year forecast, some changes have emerged that influence reactive, corrective and preventive maintenance projections, as well as vegetation management requirements.

Preventive maintenance: We have introduced a step change in distribution switchgear, reflecting a strategy change in our inspection and maintenance programme. While this increases the spend for this fleet, the overall preventive maintenance plan has not materially changed from AMP25 to AMP26.

Corrective maintenance: Our forecast for corrective maintenance has increased slightly compared to AMP25. The main drivers are the completion of the consumer lines inspection and handover programme in RY27 and an upward trend in the number of corrective defects as a direct result of the enhanced inspection and fault follow-up (RCA) investigations.

Reactive maintenance: Expenditure projections have decreased from AMP25, reflecting the lower than forecast outturn in RY25. This reduction has lowered the starting base for the AMP26 forecast model. This expenditure category is highly vulnerable to external factors such as the wind events of October 2025.

While RY26 reactive expenditure is on track, the overall 10-year comparison indicates a materially lower reactive maintenance requirement relative to AMP25. Updated inspection insights, reduced fault volumes in RY25, and improved condition information have contributed to this downward adjustment. However, this will need ongoing review to ensure we take the most informed position with respect to representative historic performance trends.

Vegetation management: In our projections, we have assumed a reduction in expenditure as we expect consumers who have declared interest and received their first cut will begin to take ownership of active management of their vegetation. At this stage we are seeing marginal benefits with the majority of those previously declaring interest opting to relinquish ownership in lieu of incurring 'second cut' costs, as afforded by the regulations. We will continue to monitor data so that trends can be identified and captured in our forecasts.

7.3.2 Material changes to our non-network opex 10-year forecast

There are no material changes to report in non-network opex.

Expenditure

7.4 Managing investment uncertainty

We maintain an ongoing process of review and challenge of our AMP forecasts and planning assumptions, informed by the best available information.

Within our growth programme, we have responded to revised demand forecast

needs by actively adjusting the timing and sequencing of investments.

We have put forward a plan that has been robustly tested considering new information, and we continue to respond to the needs of our communities.

Appendix A: Disclosure Schedules

This appendix includes the following Information Disclosure Schedules:

- 11a [REPORT ON FORECAST CAPITAL EXPENDITURE](#)
- 11b [REPORT ON FORECAST OPERATIONAL EXPENDITURE](#)
- 12a [REPORT ON ASSET CONDITION](#)
- 12b [REPORT ON FORECAST CAPACITY](#)
- 12c [REPORT ON FORECAST NETWORK DEMAND](#)
- 12d [REPORT ON FORECAST INTERRUPTIONS AND DURATION](#)
- 14a [MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION](#)

Appendix A: Disclosure Schedules

Schedule 11a: Report on Forecast Capital Expenditure

Company Name	Aurora Energy Limited
AMP Planning Period	

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7												
8												
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)										
10	Consumer connection	20,768	21,184	21,675	22,166	22,657	23,148	23,639	24,131	24,622	25,113	25,604
11	System growth	9,053	22,300	43,164	29,445	32,726	49,249	34,275	27,885	29,159	18,878	9,446
12	Asset replacement and renewal	57,071	61,685	65,115	62,457	57,337	61,321	71,376	63,058	61,526	59,568	55,554
13	Asset relocations	4,716	4,810	4,922	5,033	5,145	5,256	5,368	5,479	5,591	5,702	5,814
14	Reliability, safety and environment:											
15	Quality of supply	351	624	481	676	1,672	1,709	1,745	1,781	1,817	1,854	1,890
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,533	2,835	4,807	3,163	1,895	2,620	2,094	1,544	1,575	1,607	1,638
18	Total reliability, safety and environment	1,884	3,459	5,288	3,839	3,568	4,329	3,839	3,325	3,393	3,460	3,528
19	Expenditure on network assets	93,492	113,438	140,162	122,939	121,432	143,303	138,497	123,877	124,291	112,721	99,946
20	Expenditure on non-network assets	2,600	15,789	3,465	4,268	4,770	4,407	3,714	3,528	4,623	3,266	4,668
21	Expenditure on assets	96,091	129,227	143,627	127,207	126,203	147,710	142,211	127,405	128,913	115,987	104,614
22												
23	plus Cost of financing	1,183	1,657	1,860	1,618	1,599	1,904	1,820	1,602	1,619	1,427	1,258
24	less Value of capital contributions	14,126	14,407	14,742	15,076	15,410	15,744	16,078	16,412	16,746	17,080	17,414
25	plus Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	Capital expenditure forecast	83,148	116,476	130,745	113,750	112,392	133,871	127,953	112,595	113,786	100,334	88,458
28												
29	Assets commissioned	88,904	123,505	107,935	113,354	102,759	119,275	147,537	132,977	118,279	111,604	104,188
30												
31												
32												
33		\$000 (in constant prices)										
34	Consumer connection	20,768	20,768	20,768	20,768	20,768	20,768	20,768	20,768	20,768	20,768	20,768
35	System growth	9,053	21,884	41,474	27,713	30,238	44,659	30,483	24,394	25,029	15,955	7,846
36	Asset replacement and renewal	57,071	60,552	62,652	58,775	52,902	55,556	63,434	54,926	52,703	50,111	45,888
37	Asset relocations	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716	4,716
38	Reliability, safety and environment:											
39	Quality of supply	351	611	461	633	1,533	1,533	1,533	1,533	1,533	1,533	1,533
40	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
41	Other reliability, safety and environment	1,533	2,809	4,641	2,964	1,737	2,351	1,840	1,329	1,329	1,329	1,329
42	Total reliability, safety and environment	1,884	3,420	5,102	3,597	3,270	3,884	3,373	2,862	2,862	2,862	2,862
43	Expenditure on network assets	93,492	111,340	134,712	115,568	111,895	129,582	122,773	107,665	106,077	94,410	82,080
44	Expenditure on non-network assets	2,600	15,479	3,320	3,999	4,373	3,954	3,262	3,036	3,899	2,701	3,786
45	Expenditure on assets	96,091	126,820	138,032	119,567	116,267	133,535	126,035	110,702	109,977	97,111	85,866
46												
47	Subcomponents of expenditure on assets (where known)											
48	Energy efficiency and demand side management, reduction of energy losses											
49	Overhead to underground conversion											
50	Research and development											
51												
52												

Appendix A: Disclosure Schedules

Schedule 11a: Report on Forecast Capital Expenditure (ctd.)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
53												
54												
55	Difference between nominal and constant price forecasts	\$000										
56	Consumer connection	-	416	907	1,398	1,889	2,380	2,872	3,363	3,854	4,345	4,836
57	System growth	-	416	1,689	1,732	2,487	4,591	3,793	3,491	4,130	2,923	1,600
58	Asset replacement and renewal	-	1,133	2,462	3,682	4,435	5,765	7,942	8,131	8,823	9,457	9,666
59	Asset relocations	-	94	206	317	429	541	652	764	875	987	1,098
60	Reliability, safety and environment:											
61	Quality of supply	-	13	20	43	139	176	212	248	284	321	357
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	26	165	200	158	269	254	215	247	278	309
64	Total reliability, safety and environment	-	39	185	242	297	445	466	463	531	599	666
65	Expenditure on network assets	-	2,098	5,450	7,371	9,538	13,721	15,724	16,212	18,213	18,311	17,866
66	Expenditure on non-network assets	-	310	145	269	398	453	451	492	724	565	882
67	Expenditure on assets	-	2,407	5,595	7,640	9,936	14,175	16,175	16,704	18,937	18,876	18,748
68												
69	Commentary on options and considerations made in the assessment of forecast expenditure											
70	<i>EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15</i>											
71												
72												
73		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5					
74	11a(ii): Consumer Connection											
75	<i>Consumer types defined by EDB*</i>	\$000 (in constant prices)										
76	Consumer connection	20,768	20,768	20,768	20,768	20,768	20,768					
77	[EDB consumer type]											
78	[EDB consumer type]											
79	[EDB consumer type]											
80	[EDB consumer type]											
81	<i>*include additional rows if needed</i>											
82	Consumer connection expenditure	20,768	20,768	20,768	20,768	20,768	20,768					
83	less Capital contributions funding consumer connection	10,890	10,889	10,889	10,889	10,889	10,889					
84	Consumer connection less capital contributions	9,878	9,879	9,879	9,879	9,879	9,879					
85	11a(iii): System Growth											
86	Subtransmission	2,111	2,743	26,422	15,524	22,095	20,557					
87	Zone substations	3,510	8,790	6,765	5,559	2,273	14,009					
88	Distribution and LV lines	500	2,033	1,427	4,064	1,207	4,853					
89	Distribution and LV cables	2,772	8,318	6,860	2,566	4,664	5,240					
90	Distribution substations and transformers	-	-	-	-	-	-					
91	Distribution switchgear	161	-	-	-	-	-					
92	Other network assets	-	-	-	-	-	-					
93	System growth expenditure	9,053	21,884	41,474	27,713	30,238	44,659					
94	less Capital contributions funding system growth											
95	System growth less capital contributions	9,053	21,884	41,474	27,713	30,238	44,659					
96												

Appendix A: Disclosure Schedules

Schedule 11a: Report on Forecast Capital Expenditure (ctd.)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	
97							
98							
99	11a(iv): Asset Replacement and Renewal						
100		\$000 (in constant prices)					
101	Subtransmission	10,897	11,725	16,163	18,957	13,401	12,656
102	Zone substations	10,400	10,846	11,145	5,279	5,833	5,338
103	Distribution and LV lines	17,340	18,177	17,432	15,869	17,938	21,093
104	Distribution and LV cables	2,786	2,619	2,619	2,619	2,619	2,619
105	Distribution substations and transformers	2,272	2,190	1,868	2,317	2,100	4,367
106	Distribution switchgear	10,014	9,718	9,718	9,718	9,088	7,693
107	Other network assets	3,362	5,278	3,707	4,016	1,923	1,790
108	Asset replacement and renewal expenditure	57,071	60,552	62,652	58,775	52,902	55,556
109	less Capital contributions funding asset replacement and renewal						
110	Asset replacement and renewal less capital contributions	57,071	60,552	62,652	58,775	52,902	55,556
111							
112							
113	11a(v): Asset Relocations						
114		\$000 (in constant prices)					
115	<i>Project or programme*</i>						
116	Asset relocations	4,716	4,716	4,716	4,716	4,716	4,716
117	[Description of material project or programme]						
118	[Description of material project or programme]						
119	[Description of material project or programme]						
120	<i>*include additional rows if needed</i>						
121	All other project or programmes - asset relocations						
122	Asset relocations expenditure	4,716	4,716	4,716	4,716	4,716	4,716
123	less Capital contributions funding asset relocations	3,236	3,236	3,236	3,236	3,236	3,236
124	Asset relocations less capital contributions	1,480	1,480	1,480	1,480	1,480	1,480
125							
126							
127							
128	11a(vi): Quality of Supply						
129		\$000 (in constant prices)					
130	<i>Project or programme*</i>						
131	Reliability, safety and environment:	351	611	461	633	1,533	1,533
132	[Description of material project or programme]						
133	[Description of material project or programme]						
134	[Description of material project or programme]						
135	<i>*include additional rows if needed</i>						
136	All other projects or programmes - quality of supply						
137	Quality of supply expenditure	351	611	461	633	1,533	1,533
138	less Capital contributions funding quality of supply						
139	Quality of supply less capital contributions	351	611	461	633	1,533	1,533
140							

Appendix A: Disclosure Schedules

Schedule 11a: Report on Forecast Capital Expenditure (ctd.)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
141						
142						
143	11a(vii): Legislative and Regulatory					
144	<i>Project or programme*</i>					
145	[Description of material project or programme]					
146	[Description of material project or programme]					
147	[Description of material project or programme]					
148	[Description of material project or programme]					
149	[Description of material project or programme]					
150	<i>*Include additional rows if needed</i>					
151	All other projects or programmes - legislative and regulatory					
152	Legislative and regulatory expenditure	-	-	-	-	-
153	less Capital contributions funding legislative and regulatory					
154	Legislative and regulatory less capital contributions	-	-	-	-	-
155						
156						
157	11a(viii): Other Reliability, Safety and Environment					
158	<i>Project or programme*</i>					
159	Reliability, safety and environment:	1,533	2,809	4,641	2,964	1,737
160	[Description of material project or programme]					
161	[Description of material project or programme]					
162	[Description of material project or programme]					
163	[Description of material project or programme]					
164	<i>*Include additional rows if needed</i>					
165	All other projects or programmes - other reliability, safety and environment					
166	Other reliability, safety and environment expenditure	1,533	2,809	4,641	2,964	1,737
167	less Capital contributions funding other reliability, safety and environment					
168	Other reliability, safety and environment less capital contributions	1,533	2,809	4,641	2,964	1,737
169						
170						
171						
172	11a(ix): Non-Network Assets					
173	Routine expenditure					
174	<i>Project or programme*</i>					
175	[Description of material project or programme]	2,600	15,479	3,320	3,999	4,373
176	[Description of material project or programme]					
177	[Description of material project or programme]					
178	[Description of material project or programme]					
179	[Description of material project or programme]					
180	<i>*Include additional rows if needed</i>					
181	All other projects or programmes - routine expenditure					
182	Routine expenditure	2,600	15,479	3,320	3,999	4,373
183	Atypical expenditure					
184	<i>Project or programme*</i>					
185	[Description of material project or programme]					
186	[Description of material project or programme]					
187	[Description of material project or programme]					
188	[Description of material project or programme]					
189	[Description of material project or programme]					
190	<i>*Include additional rows if needed</i>					
191	All other projects or programmes - atypical expenditure					
192	Atypical expenditure	-	-	-	-	-
193						
194	Expenditure on non-network assets	2,600	15,479	3,320	3,999	4,373

Appendix A: Disclosure Schedules

Schedule 11b: Report on Forecast Operational Expenditure

												Company Name		
												Aurora Energy Limited		
												AMP Planning Period		
SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE														
This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.														
7	sch ref													
8		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10		
9	Operational Expenditure Forecast	\$000 (in nominal dollars)												
10	Service interruptions and emergencies	3,698	3,741	3,825	3,909	3,993	4,118	4,244	4,373	4,504	4,636	4,771		
11	Vegetation management	4,365	4,835	5,287	5,334	4,880	5,219	5,379	5,542	5,707	5,874	6,728		
12	Routine and corrective maintenance and inspection	13,298	13,848	12,420	12,888	12,635	12,927	13,280	13,699	14,040	14,493	14,886		
13	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-		
14	Network Opex	21,362	22,424	21,532	22,132	21,508	22,264	22,904	23,614	24,250	25,003	26,385		
15	System operations and network support	19,901	21,371	21,143	21,687	22,206	22,520	23,195	23,926	24,401	24,416	24,768		
16	Business support	15,618	18,220	17,110	16,861	17,357	17,099	17,591	17,960	18,286	18,753	19,101		
17	Non-network solutions provided by a related party or third party	114	32	32	33	33	-	-	-	-	-	-	Not Required before DY2025	
18	Non-network opex	35,633	39,624	38,286	38,581	39,596	39,619	40,786	41,886	42,687	43,169	43,869		
19	Operational expenditure	56,995	62,048	59,818	60,712	61,104	61,882	63,690	65,500	66,937	68,172	70,254		
20		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10		
21		\$000 (in constant prices)												
22														
23	Service interruptions and emergencies	3,698	3,659	3,657	3,654	3,652	3,687	3,721	3,756	3,792	3,827	3,863		
24	Vegetation management	4,365	4,729	5,054	4,986	4,464	4,672	4,716	4,761	4,805	4,849	5,448		
25	Routine and corrective maintenance and inspection	13,298	13,548	11,870	12,039	11,541	11,553	11,617	11,735	11,783	11,921	12,005		
26	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-		
27	Network Opex	21,362	21,935	20,581	20,680	19,657	19,912	20,055	20,252	20,379	20,597	21,316		
28	System operations and network support	19,901	20,884	20,218	20,304	20,362	20,234	20,429	20,665	20,676	20,303	20,218		
29	Business support	15,618	17,816	16,357	15,765	15,881	15,315	15,432	15,439	15,408	15,497	15,485		
30	Non-network solutions provided by a related party or third party	114	31	31	31	31	-	-	-	-	-	-	Not Required before DY2025	
31	Non-network opex	35,633	38,731	36,606	36,099	36,274	35,549	35,862	36,104	36,084	35,800	35,703		
32	Operational expenditure	56,995	60,666	57,187	56,779	55,931	55,461	55,917	56,357	56,463	56,397	57,019		
33	Subcomponents of operational expenditure (where known)													
34														
35	Energy efficiency and demand side management, reduction of energy losses													
36	Direct billing*													
37	Research and Development													
38	Insurance													
39														
40														
41	* Direct billing expenditure by suppliers that direct bill the majority of their consumers													
42														
43														
44														
45	Difference between nominal and real forecasts	\$000												
46	Service interruptions and emergencies	-	82	169	255	341	431	523	617	712	809	908		
47	Vegetation management	-	107	233	348	417	546	663	782	902	1,025	1,280		
48	Routine and corrective maintenance and inspection	-	300	550	849	1,093	1,374	1,663	1,964	2,257	2,572	2,881		
49	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-		
50	Network Opex	-	489	952	1,452	1,851	2,352	2,849	3,362	3,871	4,406	5,069		
51	System operations and network support	-	487	925	1,384	1,844	2,286	2,766	3,261	3,726	4,113	4,549		
52	Business support	-	405	754	1,096	1,476	1,784	2,159	2,521	2,877	3,256	3,617		
53	Non-network solutions provided by a related party or third party	-	1	1	2	3	-	-	-	-	-	-	Not Required before DY2025	
54	Non-network opex	-	893	1,680	2,482	3,323	4,069	4,924	5,782	6,603	7,369	8,166		
55	Operational expenditure	-	1,381	2,632	3,933	5,173	6,421	7,773	9,144	10,474	11,775	13,235		
56														
57	Commentary on options and considerations made in the assessment of forecast expenditure													
58		EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.												

Appendix A: Disclosure Schedules

Schedule 12a: Report on Asset Condition

Company Name	Aurora Energy Limited
AMP Planning Period	

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Asset condition at start of planning period (percentage of units by grade)											
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
7												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.12%	0.83%	1.46%	11.31%	86.28%		3	0.50%
11	All	Overhead Line	Wood poles	No.	0.77%	5.31%	11.25%	17.36%	65.31%		3	4.40%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A		-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	15.04%	-	5.15%	5.00%	74.81%		2	8.12%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A		-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	0.39%	0.68%	98.93%		2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	42.39%	14.96%	42.65%		2	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	100.00%	-	-		2	48.48%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	53.31%	31.59%	15.10%		2	53.50%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A		-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A		-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A		-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A		-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A		-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	32.42%	5.41%	5.41%	16.22%	40.54%		2	14.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A		-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	37.50%	62.50%		2	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	10.84%	3.61%	7.23%	26.51%	51.81%		2	22.89%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A		-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	24.49%	-	16.33%	6.12%	53.06%		2	25.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-		2	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A		-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	18.75%	81.25%		2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	13.37%	-	17.44%	18.90%	50.29%		3	15.41%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5.56%	2.78%	27.78%	38.88%	25.00%		2	58.33%
35												

Appendix A: Disclosure Schedules

Schedule 12a: Report on Asset Condition (ctd.)

		Asset condition at start of planning period (percentage of units by grade)										
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
36												
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.17%	15.87%	31.75%	7.94%	41.27%		3	14.10%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.96%	2.50%	5.67%	15.54%	72.33%		2	4.84%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A		-
42	HV	Distribution Line	SWER conductor	km	12.75%	-	-	5.59%	81.66%		2	100.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.03%	0.50%	-	0.22%	99.25%		2	0.53%
44	HV	Distribution Cable	Distribution UG PILC	km	-	0.04%	0.21%	8.56%	91.19%		2	0.17%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	30.94%	69.06%		3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	1.85%	5.56%	12.96%	79.63%		2	12.96%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	66.67%	33.33%	-	-		2	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	8.27%	4.06%	5.46%	11.37%	70.84%		2	8.13%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	0.18%	0.09%	12.81%	8.48%	78.44%		2	38.25%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	9.14%	3.54%	27.05%	20.34%	39.93%		3	10.32%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.64%	1.47%	8.30%	12.06%	74.53%		3	4.71%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.09%	0.09%	1.43%	6.12%	92.27%		3	1.17%
53	HV	Distribution Transformer	Voltage regulators	No.	12.50%	-	6.25%	37.50%	43.75%		3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	N/A		-
55	LV	LV Line	LV OH Conductor	km	9.08%	1.13%	6.71%	15.56%	67.52%		2	3.38%
56	LV	LV Cable	LV UG Cable	km	2.50%	1.23%	0.65%	5.87%	89.75%		2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	2.51%	0.96%	2.95%	19.72%	73.86%		1	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	N/A		-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	36.16%	1.85%	16.97%	20.30%	24.72%		3	31.73%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	N/A		-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	100.00%		4	-
62	All	Load Control	Centralised plant	Lot	25.00%	-	-	75.00%	-		2	-
63	All	Load Control	Relays	No.	25.00%	-	62.50%	12.50%	-		2	75.00%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A		-

Appendix A: Disclosure Schedules

Schedule 12b: Report on Forecast Capacity

Company Name **Aurora Energy Limited**
 AMP Planning Period

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref	Existing Zone Substation	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
7	12b(i): System Growth - Zone Substations																				
8	Alexandra	11.3	Winter	15	N-1 switched	No constraint	4	Winter	2	N-1	Winter	-0.4	0.6	N-1	Security	10+	Not applicable	Not applicable	Not applicable	Not applicable	
9	Clyde/Earnsclough	4.6	Summer	4	N	Capacity	-1	Summer	-1	N	Summer	-2.3	-1.6	N	Capacity	1	Zone substation transformer	Divert load to alternative substation	Implementation stage	1-3 years	Due to aging assets, the Clyde/Earnsclough (CE) substation will be replaced by the new Dunstan substation (aimed to be completed by RY27). We will transfer all CE load in RY28 and decommission CE by RY28. We have reinforced the CE distribution network to provide better back-up from Alexandra substation. We currently divert load to Alexandra substation during the summer peak period.
10	Earnsclough	-	-	2	N	No constraint	2	-	0	-	-	0	0	-	-	-	Not applicable	Not applicable	Not applicable	Not applicable	Earnsclough substation provides short term partial back-up to the CE substation. We plan to decommission Earnsclough substation when the distribution feeders of CE have been transferred to the new Dunstan substation, by RY28.
11	Ettrick	1.8	Autumn	4	N	No constraint	2	Autumn	2	N	Autumn	1.7	1.7	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	The substation is scheduled to be renewed in RY33. This provides an opportunity to install a standard transformer size and 11 kV switchgear to reconfigure the distribution network to uplift reliability. This work would also increase transfer capacity to Roxburgh.
12	Lauder Flat	1.2	Summer	3	N	No constraint	2	Summer	2	N	Summer	-0.5	1.2	N	Capacity	5	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	The Alexandra-Omakau 33 kV subtransmission (N-security) that supplies the Omakau and Lauder Flat substations is limited by low capacity sections of conductor. We are exploring options to resolve this constraint in RY28-30 by upgrading or bypassing the limiting sections.
13	Omakau	3.2	Summer	8	N	No constraint	4	Summer	3	N	Summer	-7	1.8	N	Capacity	5	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	The Alexandra-Omakau 33 kV subtransmission (N-security) that supplies the Omakau and Lauder Flat substations is limited by low capacity sections of conductor. We are exploring options to resolve this constraint in RY28-30 by upgrading or bypassing the limiting sections. This will also improve reliability to this area.
14	Roxburgh	2.1	Spring	5	N	No constraint	3	Spring	3	N	Spring	1.8	1.8	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
15	Camp Hill	6.1	Summer	8	N	No constraint	1	Summer	0	N	Summer	-1.1	-1.3	N	Capacity	9	Zone substation transformer	Network upgrade	Planning stage	Not applicable	There is strong growth in the Camp Hill (CH) substation network area. We plan to install fans to increase transformer capacity to 10 MVA in RY27.
16	Cardrona	5.7	Winter	24	N	No constraint	18	Winter	11	N	Winter	9	13.3	N	Security	10+	Not applicable	Not applicable	No active planning	Not applicable	Depending on continued load growth at Cardrona, and subject to economic assessment, we are considering installing a 66 kV line to provide N-1 capacity to the area. Feasibility is expected to become clearer toward the end of the DPP4 period.
17	Cromwell	15.7	Winter	24	N-1	No constraint	8	Winter	2	N-1	Winter	-4	-1.3	N-1	Security	9	Not applicable	Not applicable	Not applicable	Not applicable	
18	Lindis Crossing	7.9	Summer	10	N	No constraint	2	Summer	2	N	Summer	1.3	0.6	N	Capacity	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	The Lindis Crossing (LC) and Queensberry (QB) substations are interconnected and are both approaching their capacity limits. We are monitoring demand growth and spot loads, including proposals for large solar generators that have indicated a desire to connect to Lindis Crossing. Depending on how growth develops, there is an option to install a second transformer at Lindis Crossing to improve security and cater for the solar generation and demand.
19	Queensberry	2.6	Summer	4	N	No constraint	1	Summer	1	N	Summer	0.7	0.7	N	No constraint	10+	Not applicable	Network upgrade	Not applicable	Not applicable	
20	Wanaka	27.0	Winter	24	N-1	Security	-3	Winter	-1	N-1	Winter	-6	-2.2	N-1	Security	10+	Zone substation transformer	Divert load to alternative substation	Solution confirmed	1-3 years	We plan to install a 24 MVA transformer in RY27 at the Riverbank switching station and transfer some Wanaka substation load in the same year. Operationally, we have the capacity to move >1.5 MVA load to Camp Hill substation.

Appendix A: Disclosure Schedules

Schedule 12b: Report on Forecast Capacity (ctd.)

22	Arrowtown	10.3	Winter	10	N-1 switched	Security	0	Winter	-5	N-1 switched	Winter	-15.2	-7.7	N-1 switched	Security	1	Zone substation transformer	Divert load to alternative substation	Solution confirmed	1 - 3 years	Equipment at Arrowtown is nearing end of life and demand in the surrounding area is continuing to grow. New substations at Malaghans and Whitechapel are planned to support this growth and will allow the Arrowtown load to be offloaded so its condition issues can be addressed.
23	Commonage	10.9	Winter	17	N-1 switched	No constraint	6	Winter	3	N-1 switched	Winter	1.8	1.8	N-1 switched	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
24	Coronet Peak	5.3	Winter	6	N	No constraint	1	Winter	1	N	Winter	0.7	0.7	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	Coronet Peak has equipment approaching end of life. We plan to transfer the load to the new Malaghans substation, which will provide an N-1 capable supply point and allow the Coronet Peak substation to be retired.
25	Dalefield	2.0	Winter	4	N	No constraint	2	Winter	1	N	Winter	-2	0	N	Capacity	10+	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Dalefield demand is increasing and is projected to exceed the site's capacity. We plan to transfer the Dalefield load to a new Malaghans substation, which will provide an N-1 capable supply point for the area and allow the Dalefield substation to be retired.
26	Ferrihill	7.0	Winter	10	N-1 switched	No constraint	3	Winter	2	N-1 switched	Winter	-0.2	0.1	N-1 switched	Security	10+	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	The demand on the Queenstown subtransmission, which supplies the Queenstown, Ferrihill and Commonage substations, is forecast to be above its firm capacity in RY31. We plan to upgrade the limiting sections of the subtransmission to increase its capacity and security by RY30-31.
27	Frankton	18.7	Winter	24	N-1	No constraint	5	Winter	-2	N-1	Winter	-12.5	-9.2	N-1	Security	4	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Demand in the Frankton network area is growing and the Frankton substation demand forecast indicates that the load will exceed its firm capacity. We plan to transfer load to the proposed new Malaghans and Whitechapel substations.
	Queenstown	12.6	Winter	20	N-1 switched	No constraint	7	Winter	3	N-1	Winter	0.5	2.8	N-1	Security	10+	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	The demand on the Queenstown subtransmission, which supplies the Queenstown, Ferrihill and Commonage substations, is forecast to be above its firm capacity in RY31. We plan to upgrade the limiting sections of the subtransmission to increase its capacity and security by RY30-31.
	Remarkables	2.3	Winter	4	N	No constraint	1	Winter	1	N	Winter	-0.5	1.3	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Berwick	1.8	Spring	3	N	No constraint	1	Spring	1	N	Spring	1.1	1.1	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	East Taieri	18.0	Winter	23	N-1 switched	No constraint	5	Winter	3	N-1 switched	Winter	0.4	1.8	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Green Island	13.9	Winter	18	N-1	No constraint	4	Winter	9	N-1	Winter	5.1	8.9	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Halfway Bush	13.4	Winter	18	N-1	No constraint	5	Winter	10	N-1	Winter	7.8	8.6	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Kaikorai Valley	10.4	Winter	23	N-1	No constraint	13	Winter	12	N-1	Winter	11.3	11.8	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Mosgiel	7.0	Winter	12	N-1 switched	No constraint	5	Winter	2	N-1	Winter	-1.5	1	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	North East Valley	9.5	Winter	18	N-1	No constraint	9	Winter	8	N-1	Winter	7	7.7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Outram	2.9	Winter	8	N	No constraint	5	Winter	4	N	Winter	4.1	4.2	N	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Port Chalmers	7.1	Winter	8	N-1	No constraint	0	Winter	0	N-1	Winter	-1.1	-0.5	N-1	Security	4	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	The zone transformers are planned to be replaced with higher capacity in RY27-28.
	Smith Street	12.6	Winter	18	N-1	No constraint	5	Winter	3	N-1	Winter	1.3	2.1	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	The zone transformers are planned to be replaced with higher capacity in RY29-30.
	Ward Street	9.5	Winter	23	N-1	No constraint	13	Winter	7	N-1	Winter	5.8	7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Willowbank	12.0	Winter	18	N-1	No constraint	6	Winter	6	N-1	Winter	5	5.4	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Andersons Bay	13.0	Winter	24	N-1	No constraint	11	Winter	10	N-1	Winter	8.7	9.6	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Carisbrook	10.5	Winter	23	N-1	No constraint	12	Winter	12	N-1	Winter	10.2	10.8	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	Constopline	11.3	Winter	19	N-1	No constraint	8	Winter	7	N-1	Winter	5.6	6.5	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	North City	14.6	Winter	28	N-1	No constraint	13	Winter	12	N-1	Winter	11.4	11.9	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	South City	14.9	Winter	18	N-1	No constraint	3	Winter	3	N-1	Winter	2.1	2.3	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	
	St Kilda	14.2	Winter	23	N-1	No constraint	9	Winter	8	N-1	Winter	6.9	7.7	N-1	No constraint	10+	Not applicable	Not applicable	Not applicable	Not applicable	

¹ Extend table as necessary to disclose all capacity and constraint information by each zone substation

Appendix A: Disclosure Schedules

Schedule 12c: Forecast Network Demand

Company Name	Aurora Energy Limited
AMP Planning Period	

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections		Number of connections					
Number of ICs connected during year by consumer type		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
<i>Consumer types defined by EDB*</i>							
Residential		905	962	973	984	995	1,007
Load Group 0		(4)	1	3	4	5	5
Load Group 0A		28	20	16	14	13	13
Load Group 1A		3	3	3	3	3	3
Load Group 1		27	22	19	18	17	17
Load Group 2		161	90	54	36	27	23
Load Group 3		7	4	3	2	2	2
Load Group 3A		7	4	3	2	2	2
Load Group 4		3	2	1	1	1	1
Load Group 5		1	1	1	1	1	1
Street Lighting & DUML		-	-	-	-	-	-
Connections total		1,138	1,109	1,076	1,065	1,066	1,074
<i>*include additional rows if needed</i>							
Distributed generation							
Number of connections made in year		943	943	943	943	943	943
Capacity of distributed generation installed in year (MVA)		9	9	9	9	9	9
12c(ii): System Demand							
Maximum coincident system demand (MW)							
GXP demand		289	281	305	313	326	337
plus	Distributed generation output at HV and above	29	45	45	45	45	45
Maximum coincident system demand		318	326	350	358	371	382
less	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
Demand on system for supply to consumers' connection points		318	326	350	358	371	382
Electricity volumes carried (GWh)							
Electricity supplied from GXPs		1,185	1,207	1,229	1,252	1,275	1,299
less	Electricity exports to GXPs	43	43	43	43	43	43
plus	Electricity supplied from distributed generation	360	369	378	386	395	404
less	Net electricity supplied to (from) other EDBs	3	3	3	3	3	3
Electricity entering system for supply to ICs		1,500	1,530	1,561	1,592	1,624	1,657
less	Total energy delivered to ICs	1,438	1,466	1,496	1,526	1,557	1,588
Losses		62	64	65	66	68	69
Load factor		54%	54%	51%	51%	50%	50%
Loss ratio		4.2%	4.2%	4.2%	4.2%	4.2%	4.2%

Appendix A: Disclosure Schedules

Schedule 12d: Reliability Forecast (Total)

		Company Name	Aurora Energy Limited					
		AMP Planning Period						
		Network / Sub-network Name	Total Network					
SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION								
This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.								
<i>sch ref</i>			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8								
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		140.3	153.8	151.0	152.2	162.9	156.8
12	Class C (unplanned interruptions on the network)		245.0	138.6	137.4	136.2	134.5	132.7
13	SAIFI							
14	Class B (planned interruptions on the network)		0.53	0.52	0.52	0.51	0.53	0.56
15	Class C (unplanned interruptions on the network)		1.85	1.91	1.90	1.88	1.86	1.83

Schedule 12d: Reliability Forecast (DN)

		Company Name	Aurora Energy Limited					
		AMP Planning Period						
		Network / Sub-network Name	Dunedin					
SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION								
This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.								
<i>sch ref</i>			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8								
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		122.6	86.1	92.6	85.4	111.0	97.4
12	Class C (unplanned interruptions on the network)		269.7	63.4	63.3	63.2	63.1	62.9
13	SAIFI							
14	Class B (planned interruptions on the network)		0.47	0.34	0.36	0.33	0.43	0.38
15	Class C (unplanned interruptions on the network)		1.20	0.93	0.93	0.93	0.93	0.93

Appendix A: Disclosure Schedules

Schedule 12d: Reliability Forecast (CW)

		Company Name		Aurora Energy Limited				
		AMP Planning Period						
		Network / Sub-network Name		Central Otago & Wanaka				
SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION								
This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.								
<i>sch ref</i>								
8			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		156.5	221.0	241.4	203.8	176.0	277.1
12	Class C (unplanned interruptions on the network)		245.0	291.8	287.7	283.6	277.4	271.3
13	SAIFI							
14	Class B (planned interruptions on the network)		0.66	0.70	0.76	0.64	0.56	0.87
15	Class C (unplanned interruptions on the network)		3.40	3.90	3.84	3.79	3.71	3.63

Schedule 12d: Reliability Forecast (QT)

		Company Name		Aurora Energy Limited				
		AMP Planning Period						
		Network / Sub-network Name		Queenstown				
SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION								
This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.								
<i>sch ref</i>								
8			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9								
10	SAIDI							
11	Class B (planned interruptions on the network)		180.7	299.4	225.9	305.7	268.2	226.4
12	Class C (unplanned interruptions on the network)		153.4	199.5	196.1	192.8	187.8	182.7
13	SAIFI							
14	Class B (planned interruptions on the network)		0.55	0.95	0.72	0.97	0.85	0.72
15	Class C (unplanned interruptions on the network)		1.81	2.86	2.81	2.76	2.69	2.62

Appendix A: Disclosure Schedules

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Differences between constant and nominal forecasts are a direct output of our escalation approach. Our expenditure forecasts were determined in constant 2026 dollars and escalated to nominal dollars using forecast price indices. Each expenditure category is escalated separately using price indices specific to that category. Price indices for each expenditure category reflect a combination of labour and materials prices. Forecast labour and materials prices are obtained from a variety of sources.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

Appendix B: Disclosure Requirements

Requirement	AMP reference
2.6.3 Subject to clause 2.6.4, an EDB may elect to complete and publicly disclose an AMP update, as described under clause 2.6.5 before the start of a disclosure year, instead of an AMP, as described under clause 2.6.1(1), unless the start of that disclosure year is-	On 6 August 2025 the Commerce Commission granted Aurora Energy an exemption allowing us to disclose an AMP update rather than a full AMP, by 1 April 2026.
(1) one year after the start of the DPP regulatory period; or	
(2) two years before the start of the next DPP regulatory period.	
2.6.4 An EDB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.	Aurora Energy's most recent, previous disclosure was its 2025 AMP.
2.6.5 [T]he AMP update must -	
(1) Relate to the electricity distribution services supplied by the EDB;	
(2) Identify any material changes to the network development plans disclosed in the last AMP under clause 11 and clause 17.5-17.7 of Attachment A or in the last AMP update disclosed under this clause;	Section 6
(3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 12 of Attachment A or in the last AMP update disclosed under this section;	Section 4
(4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b;	Section 7
(5) Identify any changes to the asset management practices of the EDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and	Section 3 - There have been no material changes to asset management practices since the publication of our AMP 2025 that would affect a Schedule 13 Report on Asset Management Maturity
(6) Contain the information set out in the schedules described in clause 2.6.6.	Appendix A

Appendix B: Disclosure Requirements

2.6.6	Each EDB—	
(1)	must, except as provided in subclause 2.6.6(2), before the start of each disclosure year, complete and publicly disclose each of the following reports by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in the following reports—	
(a)	the Report on Forecast Capital Expenditure in Schedule 11a;	Appendix A
(b)	the Report on Forecast Operational Expenditure in Schedule 11b;	Appendix A
(c)	the Report on Asset Condition in Schedule 12a;	Appendix A
(d)	the Report on Forecast Capacity in Schedule 12b;	Appendix A
(e)	the Report on Forecast Network Demand in Schedule 12c;	Appendix A
(f)	the Report on Forecast Interruptions and Duration in Schedule 12d;	Appendix A
(2)	must, before the start of each disclosure year, complete and disclose to the Commission the Report on Cybersecurity Expenditure Forecast in Schedule 11c by inserting all information relating to the electricity distribution services supplied by the EDB for the disclosure years provided for in that report; and	Commission only
(3)	must, if the EDB has sub-networks, complete and publicly disclose the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the electricity distribution services supplied by the EDB in relation to each sub-network for the disclosure years provided for in the report.	Appendix A
2.7.2	Before the start of each disclosure year, every EDB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	Appendix A
2.9.1	Where an EDB is required to publicly disclose any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Appendix C

Appendix C: Directors' Certificate

Certification for Year beginning Disclosures

Clause 2.9.1

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:

- a) The following attached information of Aurora Energy Limited prepared for the purposes of clauses 2.6.3, 2.6.5, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.
- c) The forecasts in Schedules 11a, 11b, 11c, 12a, 12b, 12c, and 12d are based on objective and reasonable assumptions which both align with Aurora Energy Limited's corporate vision and strategy and are documented in retained records.



Director



Director

26 March 2026

Date

26 March 2026

Date