

# **Verification Report**

## Aurora Energy CPP Application

8 June 2020

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# Abbreviations

Term	Definition
ACE	Annual Committed Expenditure
ACSR	Aluminium Conductor Steel Reinforced
AER	Australian Energy Regulator
AHI	Asset Health Index
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
Augex	Augmentation Expenditure
CAIDI	Customer Average Interruption Duration Index
Capex	Capital Expenditure
CDS	Controlled Document System
CoF	Consequence of Failure
CPP	Customised Price Path
DPP	Default Price Path
EAM	Enterprise Asset Management
EDB	Electricity Distribution Business
EEA	Electricity Engineers Association
ERP	Enterprise Resource Planning
FMECA	Failure Model, Effects and Consequences Assessment
FSA	Field Services Agreement
FTTP	Fast Track Pole Program
GEIP	Good Electricity Industry Practice
GIS	Geographical Information System
GXP	Grid Exit Point
HV	High Voltage
ICP	Installation Control Point
ICT	Information and Communications Technology
IM	Electricity Distribution Services Input Methodologies Amendments Determination (No. 2) 2019

Term	Definition
KPI	Key Performance Indicator
LV	Low Voltage
NZEC	New Zealand Electrical Code of Practice
OEM	Original Equipment Manufacturer
Opex	Operating Expenditure
POD	Portfolio Overview Document
PoF	Probability of Failure
PPM	Portfolio Programme Management
Repex	Replacement Expenditure
RFI	Request For information
RY	Refers to regulatory years ending 31 March. For instance, RY22 is the year ending 31 March 2022 and RY26 is the year ending 31 March 2026
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SONS	System Operation and Network Support
Totex	Total Expenditure
VoLL	Value of Lost Load
ZSS	Zone Sub Station

# 1. Summary

## 1.1 PURPOSE OF THIS REPORT – TO ASSIST THE COMMISSION’S DETERMINATION

This verification report concerns Aurora Energy’s application to the New Zealand Commerce Commission (the Commission) for a Customised Price Path (CPP) for the three-year period from 1 April 2021 to 31 March 2024 (the CPP period).

Under the CPP framework, Aurora Energy’s CPP would ordinarily apply for a five-year period, or from 1 April 2021 to 31 March 2026 (the review period).<sup>1</sup> Aurora Energy has decided to submit its CPP for a three-year period given that it does not believe that it can confidently determine its forecast expenditure requirements for the period 1 April 2024 to 31 March 2026. This is because significant organisational changes have been made since Aurora Energy separated from Delta in 2017 with further significant organisational changes planned over the CPP period to address Aurora Energy’s electricity network not meeting minimum safety and reliability requirements.<sup>2</sup> Aurora Energy expects that it will be able to do so closer to 2024 when new investment has been incurred, and new systems and processes implemented to address current operational shortfalls. Having said that, Aurora Energy has prepared forecasts for the review period which we have also considered. Therefore, our findings consider whether Aurora Energy’s forecasts over the CPP period and review period meet the requirements of the Electricity Distribution Services Input Methodologies Amendments Determination (No. 2) 2019 (IM).

This report has been prepared by Farrier Swier Consulting Pty Ltd (farrierswier) with input from GHD Pty Ltd (GHD) in accordance with the IM and in the expectation that the report will be used by the Commission to inform its own analysis and decisions around Aurora Energy’s CPP, particularly in relation to the proposed capital expenditure (capex) and operating expenditure (opex) over the CPP and review periods.<sup>3</sup> This verification report is based on information provided as at 5 June 2020 by Aurora Energy in the form of data and documents uploaded to a SharePoint site managed by Aurora Energy and responses to questions.<sup>4</sup>

The report has been structured and drafted to assist the Commission’s considerations:

- It explicitly provides opinions and advice on the matters set out in the IM.
- Given the inherent subjectivity involved in assessing forecasts, it highlights where we have drawn on professional experience and judgement and explains the reasons for our views.
- It explains the overall approach to the verification, the extent of information and analysis prepared and provided by Aurora Energy, and the iterative process used to verify the CPP.

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<sup>1</sup> Throughout the report we have used the shorthand ‘RY’ to refer to regulatory years ending 31 March. For instance, RY22 is the year ending 31 March 2022 and RY26 is the year ending 31 March 2026.

<sup>2</sup> As discussed in section 1.4 and throughout this report, the unique circumstances created by the COVID-19 pandemic are also likely to make it hard for Aurora Energy to confidently forecast what is required across its network for the period 1 April 2024 to 31 March 2026.

<sup>3</sup> The source for the IM is: Commerce Commission, Electricity Distribution Services Input Methodologies Determination 2012, This consolidated determination consolidates the principal determination and all amendments as of 31 January 2020.

<sup>4</sup> The one exception is Aurora Energy’s revised planned reliability forecasts (v5.05), which it provided to us on 20 May 2020. Due to timing, we were only able to undertake a limited review of the updated modelling before providing Aurora Energy with our penultimate draft report on 22 May 2020 and this final report.

- It highlights matters that we suggest be considered or investigated by the Commission as part of its deliberations because, for example, judgement about the specific activities and costs depends on the Commission's philosophy and policy position; we have assessed that the costs do not meet the expenditure objective; or the costs were unable to be fully verified in the time available based on the information provided.
- While our opinions and advice do not extend to providing alternative forecasts or proposing modifications, where possible, we indicate the approximate relative magnitude of any issues in the context of the total forecast capex and opex, and if appropriate, specific analysis that the Commission could complete to satisfy itself as to what the appropriate level of forecasts are.<sup>5</sup>

The verification process and report does not extend to a holistic assessment of the CPP or address other objectives that may be relevant to the Commission's determination, such as rate of return and price outcomes.

## 1.2 AURORA ENERGY'S CPP PROPOSAL

The CPP proposal covers the three-year period from 1 April 2021 and Aurora Energy forecasts approximately \$381.8 million (\$2020) of capital and operating expenditures, or \$606.5 million (\$2020) over the five-year review period starting on the same date.<sup>6</sup> This compares to the \$426.2 million expected to be spent by Aurora Energy over the five-year period that ended on 31 March 2020.<sup>7</sup>

Aurora Energy's consultation material, prepared before the emergence of the COVID-19 pandemic, explained that the increased CPP investment is associated with:

1. **Safety and reliability** – addressing concerns raised in recent years about the condition of key asset fleets that are leading to unacceptable safety risks and reliability outcomes that are breaching quality standards
2. **Network growth and resilience** – responding to continued growth across its network, particularly in the Queenstown and Wanaka areas, while ensuring that the network is robust enough to weather and other challenges that may arise
3. **Future technology** – preparing the network for the future by both modernising its tools as well as anticipating that consumers are changing how they use the network, including with electricity vehicles and solar panels
4. **Customer service** – improving the consumer experience, including through notifications of planned works.

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<sup>5</sup> In some cases, we have developed alternative forecasts to test those proposed by Aurora Energy. Although these alternative forecasts informed our opinions, we do not necessarily recommend that they should substitute for Aurora Energy's forecasts.

<sup>6</sup> For presentation purposes, all values are reported in real \$2020 unless otherwise stated – which means that they exclude cost escalation. This aligns with how Aurora Energy presents its expenditure forecasts in most of the information that it provided to us, including in Aurora Energy's descriptions of the expenditure programs. We consider the impact of cost escalation separately in section 6.4. Where appropriate, we report financial values for both the CPP and review periods.

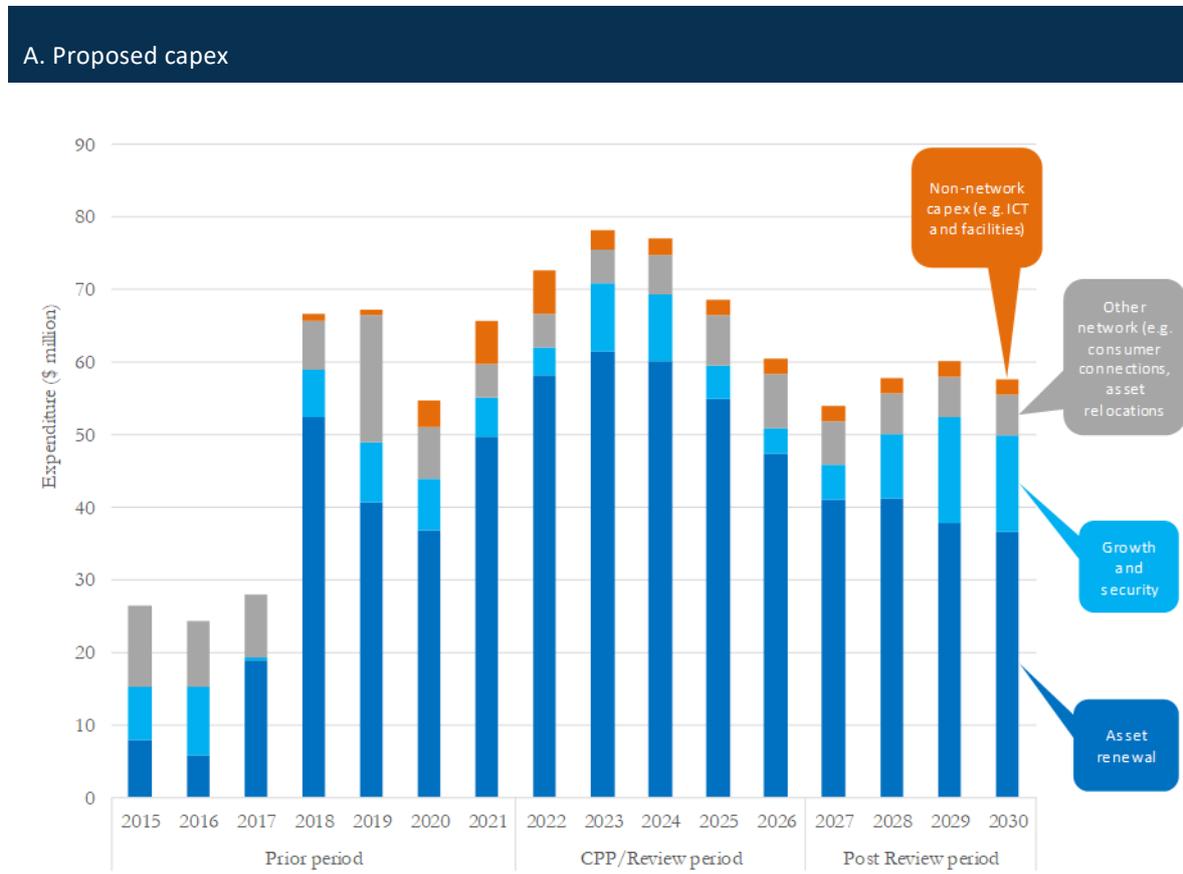
Unless otherwise stated, we have also presented capex net of any capital contributions, consistent with how Aurora Energy presents that expenditure in its CPP application and supporting material.

<sup>7</sup> At the time of writing, RY20 expenditure was estimated rather than actual expenditure. We sourced the estimate from the spreadsheet '01 - Forecast Tracker - Post IV Review', provided to us by Aurora Energy.

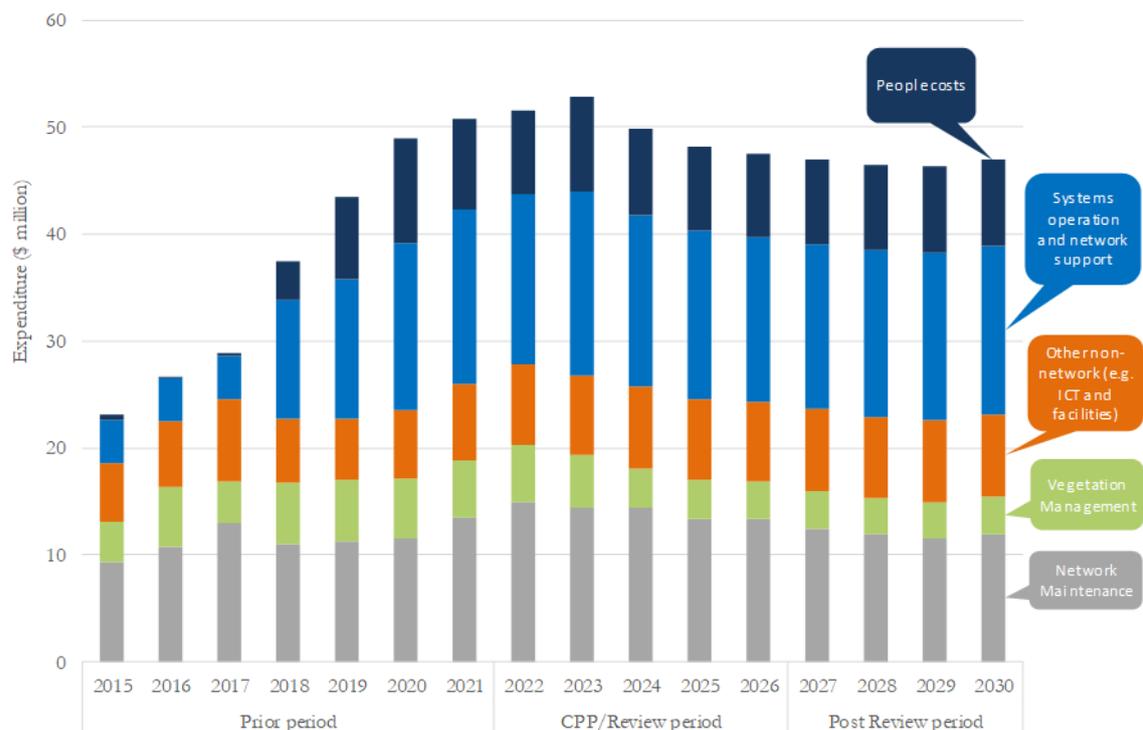
The CPP includes the costs of capital and operating works to address backlogs of renewals and maintenance, meet vegetation management requirements, address deteriorating asset condition, stabilise network performance and equip the network for the future, among other requirements.

Figure 1.1 shows the profile of the proposed capital and operating expenditures and indicates the contribution of key cost categories and drivers.

Figure 1.1 – Expenditure forecasts



## B. Proposed opex



We understand that the draft CPP proposal (as consulted on with customers) would give rise to an average price increase, ignoring inflation, of between 16% and 20% across the Dunedin, Queenstown and Central Otago / Wanaka regions, which mean average increase of approximately \$59 to \$80 per month for residential customers by RY24.<sup>8</sup> These are significant increases that for many consumers will be concerning.

### 1.3 IMPACT OF VERIFICATION PROCESS ON EXPENDITURE FORECASTS

The IM contemplates that the verification process may give rise to adjustments to the CPP because of matters raised and further analysed.

Aurora Energy has actively considered feedback provided by us throughout the process and the potential impact of the COVID-19 pandemic. As a result, Aurora Energy amended the initial forecasts that it provided us to:<sup>9</sup>

- reduce forecast low voltage (LV) enclosure renewal volumes – reducing capex by \$2.2 million over the CPP period
- rebalance its forecast zone substation expenditure – slightly increasing forecast capex by \$0.2 million over the CPP period
- moderate its base connection expenditure forecast – reducing capex by \$2.3 million over the CPP period

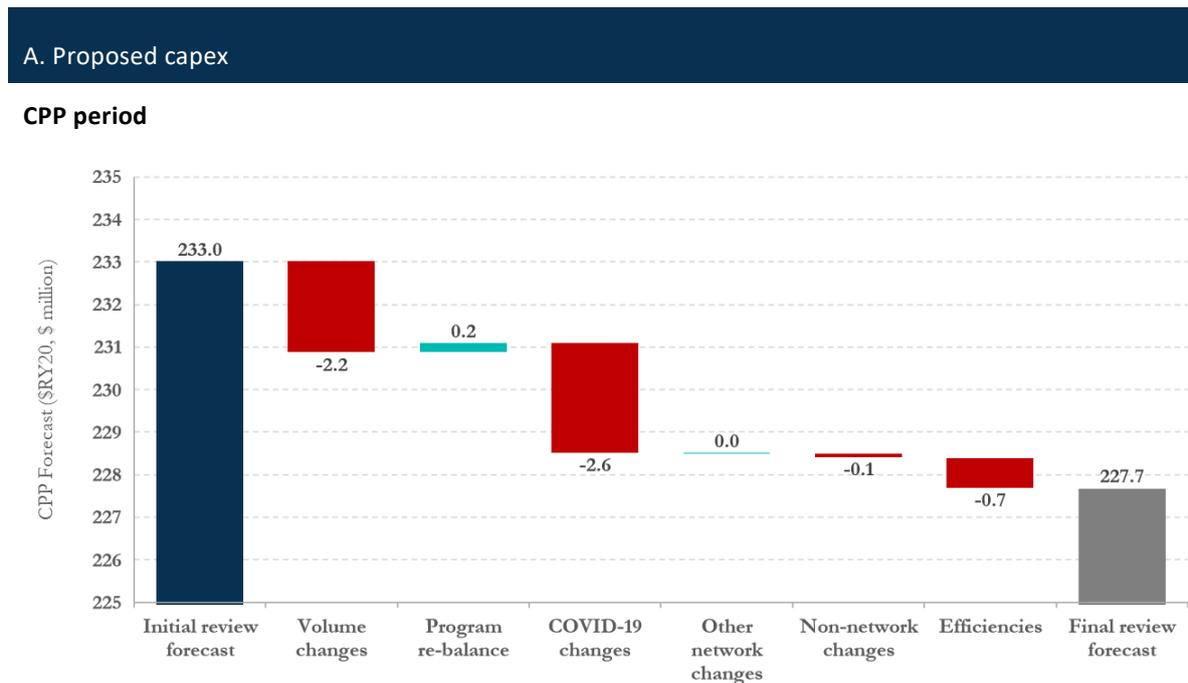
<sup>8</sup> Aurora Energy, *CPP Stakeholder Briefing*, 13 November 2019. Changes to the forecasts since those consulted on in 2019 will have likely changed the indicative price increases.

<sup>9</sup> Aurora Energy provided its initial forecasts to us in March 2020. The revised forecasts were provided to us in early May 2020. Our verification focuses on the latter forecasts.

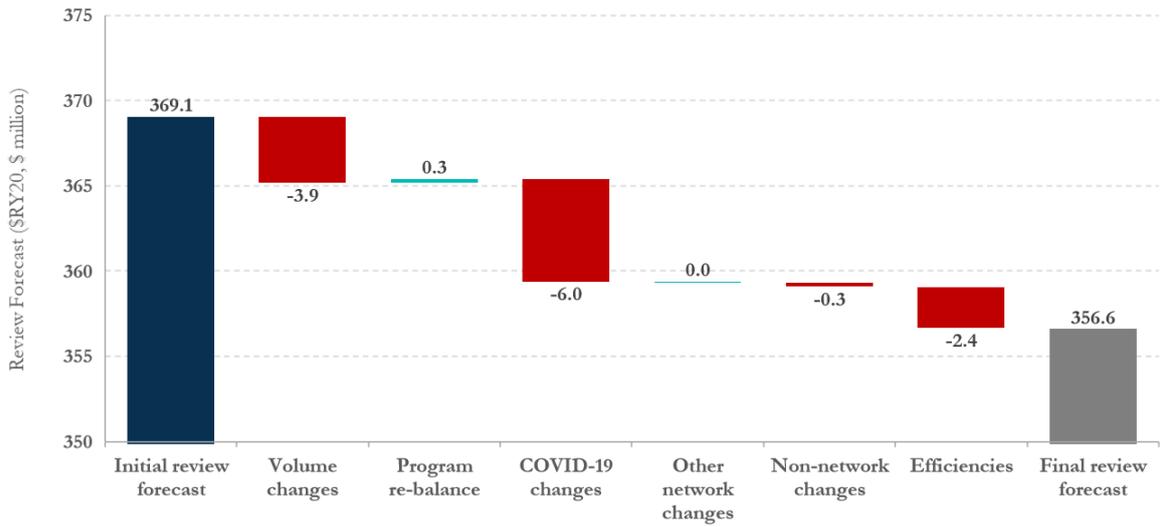
- defer and rebalancing growth projects – reducing capex by \$0.3 million over the CPP period
- reduce or adjust step changes and base year adjustments – reducing opex by \$1.0 million over the CPP period
- add in some overlooked information and communication technology (ICT) costs– decreasing capex by \$0.1 million and increasing opex by \$4.0 million over the CPP period
- overlay top-down efficiency adjustments – reducing capex and opex by \$0.7 million and \$0.9 million respectively over the CPP period.

In aggregate, and in response to our draft verification findings, Aurora Energy reduced its capex forecasts by \$5.3 million (a 2.3% reduction) and increased its opex by \$2.1 million (a 1.4% increase) over the CPP period, or a \$12.4 million reduction and \$1.4 million increase over the review period respectively (see Figure 1.2).

Figure 1.2 – Aurora Energy changes to expenditure forecasts

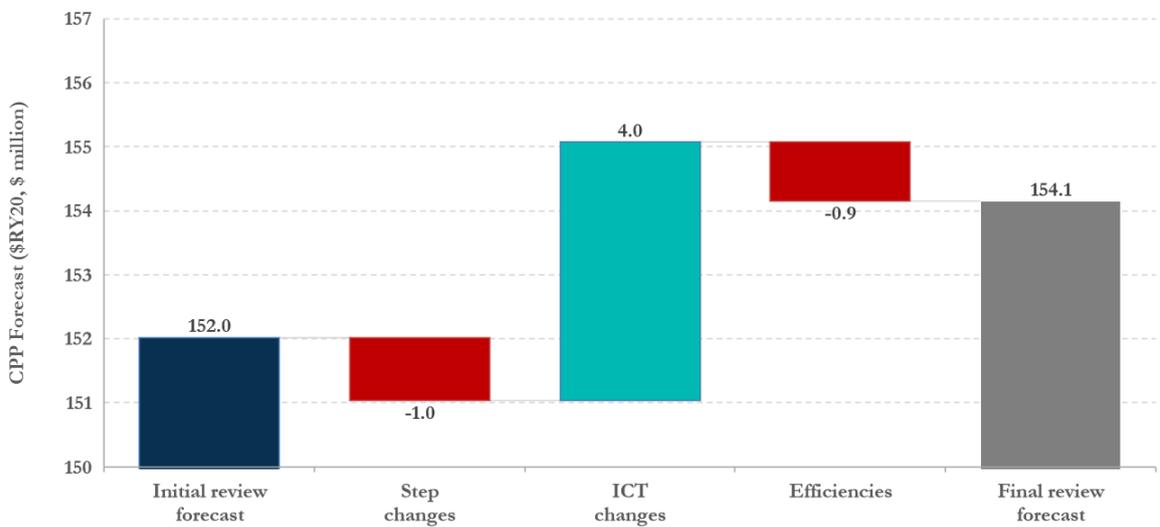


**Review period**

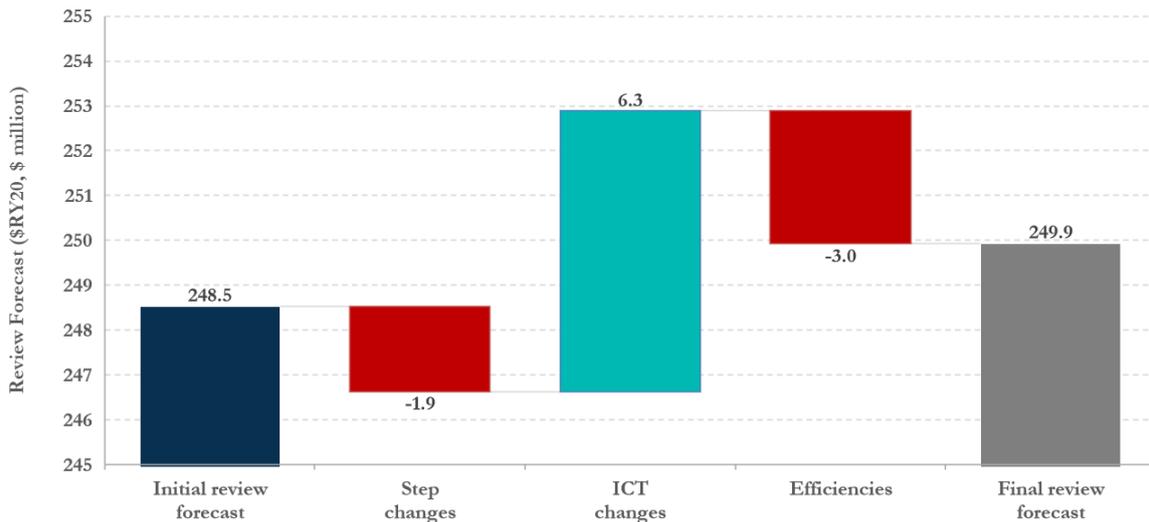


**B. Proposed opex**

**CPP period**



## Review period



Source: Aurora Energy data. Farrierswier and GHD analysis.

- (a) The ‘initial review forecast’ is the forecast that we reviewed when preparing our draft verification report. The ‘final review forecast’ is the forecast we reviewed when preparing this final verification report.

Aurora Energy also revised its quality standard variations, including to only propose increases to the unplanned system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) limits (relative to those in the DPP3 determination).<sup>10</sup> Previously, Aurora Energy was also considering changes to the planned SAIFI limit and the incentive rate used in the quality incentive scheme.

## 1.4 COVID-19 PANDEMIC

The COVID-19 pandemic and expected economic impact is likely to affect the costs and demand faced by Aurora Energy, at least in the short to medium term, as well as the activities that it can undertake in the near term (i.e. due to restrictions on non-essential activities). However, at the time of writing, it was too early to tell what that impact would be and what it means for Aurora Energy’s forecast expenditure.

Aurora Energy’s initial expenditure forecasts were prepared – and consumer and stakeholder engagement undertaken – before the pandemic was declared and the potential global health and economic impact known. As such, it is unsurprising that those forecasts and any stakeholder feedback do not account for that impact.

Since then, Aurora Energy has revised its forecasts to reflect the potential impact of the pandemic on the timing and need for expenditure.<sup>11</sup> Specifically, in response to potential reductions to underlying demand and connection activity, Aurora Energy has adjusted its capex forecasts to:<sup>12</sup>

- defer proposed major growth projects
- defer proposed distribution and LV reinforcement projects

<sup>10</sup> Throughout this report we refer to the default price path determination made in November 2019 for New Zealand non-exempt EDBs as the ‘DPP3 determination’. That determination is a useful reference as it set the price quality path currently applying to Aurora Energy.

<sup>11</sup> Aurora Energy explains the basis for these changes in: Aurora Energy, *Memo from Glenn Coates to Eli Grace-Webb, Response to Follow-up questions prompted by Commission feedback*, 12 May 2020.

<sup>12</sup> See: Aurora Energy, *Summary of Covid-19 moderations*, 12 May 2020.

- reduce connection expenditure.

These changes lowered forecast capex over the CPP and review periods by \$2.7 million and \$6.1 million respectively.

Although these changes are not unreasonable in the circumstances, there remains significant uncertainty over what the true impact of the pandemic will be. Aurora Energy's network area covers regions that are likely to be heavily affected by the crippling of international tourism – which is likely to affect demand on its network over the next few years. A sustained economic downturn could also significantly affect labour and material costs. A worsening of health outcomes – and associated travel and other restrictions – could hamper deliverability of network activities.

Such *potential* impacts are hard to predict right now. As such, our report does not make specific predictions. We do, however, note instances where forecasts will likely be affected by the COVID-19 pandemic and the expected economic fallout.

We recommend that the Commission and Aurora Energy consider this further during subsequent steps in the CPP application process, including as to whether some mechanism could be used to account for pandemic related uncertainty. The Commission's forthcoming public consultation on Aurora Energy's CPP application should give consumers and other stakeholders opportunity to reconsider their feedback, if any, in light of the pandemic.

## 1.5 VERIFICATION FINDINGS

We have presented our findings as follows:

- To provide context and perspective for the detailed verification findings, our introductory comments focus on our overall finding in terms of the quantum of expenditure verified, and the key reasons for unverified expenditure.
- Table 1.1 summarises our overall assessment against the Schedule G IM requirements which includes a range of matters. The reasons for our overall assessment are set out in detail throughout the body of our report.
- Subsequent subsections provide more detail around key Schedule G IM matters.

### 1.5.1 Overall findings – introductory commentary

Aurora Energy is addressing specific network safety and reliability needs, is on an asset management journey, and is preparing its network for the future. This means that:

- Increased capex and opex spend is required to reduce safety risk, stabilise asset performance, and generally improve asset condition through addressing a rising backlog of asset renewals and maintenance and to support good electricity industry practice asset management such as on systems to provide better quality information and analysis, which are expected to reduce expenditure needs in the longer term.
- While Aurora Energy intends to implement good asset management practices, in the immediate term its expenditure forecasts reflect, at least in part, current practices and information.
- Aurora Energy has an increased focus on managing and reducing risk; this is consistent with prudent practice – in some areas, however, recent activities and expenditure were arguably below that associated with prudent practice, and some catch-up is required.

Figure 1.3 shows that we have been able to verify most of the forecast expenditures proposed by Aurora Energy in its CPP proposal. The figure shows the amounts that we were unable to verify against the

expenditure objective from our review of the information provided to us by Aurora Energy,<sup>13</sup> and on which we recommend that the Commission focus its review – we refer to these as ‘unverified’. The figure also shows expenditure that we have not reviewed as part of our verification or consider could be considered contingent projects, which the Commission may want to focus on as well.<sup>14</sup>

Importantly, by identifying some forecast expenditure as unverified, we are not saying that it does not satisfy the expenditure objective. Rather, we are saying that we could not satisfy ourselves that it did based on the information available, or that the identified need for the expenditure was insufficient to support the proposed amounts. The Commission may – with further information and analysis, or an alternative perspective – satisfy itself that some or all of these amounts meet the expenditure objective. We have suggested additional information or lines of inquiry that may assist the Commission (see section 1.5.10 and chapter 7).

Figure 1.3 – Overall findings



- (a) The figure identifies the share of Aurora Energy’s proposed expenditure over the CPP and review periods that we have been unable to verify against the expenditure objective, could be classified as contingent (being a capex contingent project), or have not reviewed, in real 2020 dollars. Cost escalation is not reflected in the figure. We consider cost escalation separately in section 6.4 below.

<sup>13</sup> We discuss our interpretation of the expenditure objective, and our role as verifier more generally, in section 2.2.

<sup>14</sup> To be clear, we are unable to provide opinions about the expenditure that we have not reviewed because we did not have access to the information needed to do so.

In relation to the unverified amounts, part relates to potential inefficiency in the base costs used to forecast some expenditure (e.g. vegetation management). Another part of the unverified amounts relates to proposed step changes that either appeared too large or were not clear based on the information provided. A further part relates to the trend used to project forward some opex categories. And a final part relates to refinement to Aurora Energy’s pole asset strategy to include some reinforcement (e.g. nailing) later in the review period. We do not believe that the costs associated with these four parts necessarily meet the expenditure objective.

Section 1.5.10 identifies key issues that the Commission should focus on when undertaking its own review of the information provided by Aurora Energy, including as to the unverified amounts.

## 1.5.2 Overall assessment against the Schedule G IM requirements

A summary of our overall findings is provided in Table 1.1. Although focused on the CPP period, we have also identified specific findings relevant to the final two years (RY25 and RY26) of the review period.

Table 1.1 – Overall assessment

IM clause	Description	Our finding for the CPP period	Specific findings for RY25 and RY26
G2(b)	Assessing the extent to which the CPP applicant’s policies allow the CPP applicant to meet the expenditure objective	Aurora Energy is in a relatively early stage of implementing a comprehensive set of policies as part of its asset management journey. Those that we have seen generally appear to be of the nature and quality required to meet the expenditure objective.  However, we have identified some areas where policies do not yet exist or cannot be fully implemented because Aurora Energy’s current systems and processes are not ready, which are set out in sections 4.2 and 5.2.	If Aurora Energy can achieve ISO55001 certification by RY23, then its expenditure forecast for a second CPP period starting in RY25 should be significantly improved.
G2(c)	Assessing the extent to which the CPP applicant’s policies have been implemented	On the whole, we believe that Aurora Energy’s capex and opex forecasts are consistent with its policies. Where there are gaps in its policies, those forecasts generally appear consistent with policies that we expect a prudent electricity distribution business (EDB) would have.	Nothing additional.

IM clause	Description	Our finding for the CPP period	Specific findings for RY25 and RY26
G2(e) and equivalent clauses in G5 and G6	Providing an opinion to the CPP applicant on whether the CPP applicant's capex forecasts, opex forecasts and key assumptions meet the expenditure objective	<p>There are many aspects of Aurora Energy's capex and opex forecasts and supporting assumptions that support the expenditure objective.</p> <p>However, it is not possible to conclude that the total proposed expenditure over the CPP period fully meets the expenditure objective. We have identified in sections 1.5.4 and 1.5.5 areas in the expenditure forecast where we believe the capex and opex forecasts do not meet the expenditure objective.</p> <p>The proposed expenditure on the Arrowtown 33 kV project could be considered as a contingent project, especially given the potential impact of the COVID-19 pandemic.</p>	<p>Some forecast expenditure unique to RY25 and RY26 does not appear to meet the expenditure objective at this stage, including pole fleet renewal.</p> <p>The proposed major tourism operator's connection upgrade project could also be considered contingent.<sup>15</sup></p>
G2(f) and equivalent clauses in G5 and G6	Assessing the extent to which the CPP applicant is able to deliver its capex forecast and opex forecast during the CPP regulatory period	Aurora Energy's approach to deliverability appears well considered, and discussions with service providers are well advanced. There are risks associated with its deliverability plan, but we expect that Aurora Energy can and will manage them.	Nothing additional.
G2(g)	Providing an opinion on the extent and effectiveness of the CPP applicant's consultation with its consumers	<p>Aurora Energy has undertaken substantial consumer consultation to date and has prepared and made available a significant amount of material, consistent with requirements of the IM.</p> <p>Given that Aurora Energy's proposals have changed somewhat since consultation occurred, the Commission's public consultation will provide consumers with an opportunity to engage with those changes.</p> <p>The current COVID-19 pandemic is likely to heighten consumers' concerns about how the CPP proposal will affect electricity prices.</p>	Aurora Energy focused its consultation on the CPP period and so did not specifically engage with consumers on its plans for RY25 and RY26.

<sup>15</sup> Throughout this report we have referred to a major tourism operator rather than the operator's name directly to preserve confidentiality.

IM clause	Description	Our finding for the CPP period	Specific findings for RY25 and RY26
G11 and G2(d)	Assessing whether the CPP applicant has provided the verifier with the information specified in clause 5.5.2(3)	The core material and models which Aurora Energy has provided are of an appropriate standard. Aurora Energy responded to over 450 questions and requests for information and supporting models and uploaded over 800 documents and spreadsheets to its SharePoint site.	Nothing additional.
G12 and G2(h)	Providing a list of the key issues which it considers the Commission should focus on when assessing the CPP proposal	We have set out in section 1.5.10 the focus areas that the Commission may wish to consider.	Nothing additional.

### 1.5.3 Expenditure objective

There are many aspects of Aurora Energy’s capex and opex forecasts and supporting assumptions that support the expenditure objective. Aurora Energy also appears to have gone through a rigorous internal review and moderation process.<sup>16</sup> However, it is not possible for us to conclude, in terms of the IM requirements, that the total proposed expenditure over the CPP and review periods fully meet the expenditure objective.

Based on the analysis that we have performed, information reviewed, matters considered and the assessment techniques that we have applied, Aurora Energy’s capex and opex forecasts and supporting assumptions for the CPP and review periods do not fully meet the expenditure objective because it is – in some respects – in excess of what is a reasonable forecast to:

- meet or manage expected demand at appropriate service standards, and
- comply with applicable regulatory obligations.

Our reasons for this opinion are set out below.

### 1.5.4 Capital expenditure

Although most components of Aurora Energy’s capex forecasts support the expenditure objective, we consider that Aurora Energy’s capex forecast and supporting assumptions for the CPP and review periods do not fully meet the expenditure objective because:

- The potential for wood pole replacement vs. reinforcement strategy from RY25 onwards based on improved asset condition data and refined asset strategy (that will enable precise risk assessment, proactive and optimised intervention) have not been considered in the forecast for the review period. This has the potential to reduce the pole fleet renewal expenditure by \$3.3 million in the review period.
- The proposed Arrowtown 33 kV ring upgrade project appears reasonable; however, the economic justification depends on projected demand being realised. Given the significant impact that the

<sup>16</sup> See, for instance: Aurora Energy, *CPP update – Proposed submission forecast*, 4 May 2020.

COVID-19 pandemic is likely to have in the area affected by the project, we consider the upgrade could be treated as a contingent project. This project contributes \$5.4 million over the CPP period.

- Proposed major tourism operator's connection expenditure remains uncertain, especially given the impact that the COVID-19 pandemic is having on tourism. Although we are comfortable with Aurora Energy's forecast expenditure of \$2.1 million over the last two years of the review period, it is contingent on the major tourism operator formally requesting a connection upgrade.<sup>17</sup> We consider the upgrade could be treated as a contingent project.

In aggregate, these issues are likely to result in expenditure that is too high by up to approximately \$3.3 million over the review period (and none over the CPP period), or approximately 0.9% of Aurora Energy's forecast capex – as shown in Figure 1.3. This value does not include assessment of the growth-related projects (including the major tourism operator's connection upgrade) that may also be contingent projects, which contribute \$5.4 million and \$7.5 million over the CPP and review periods respectively – so the unverified components could be higher if the needs for the projects do not arise over the periods.

Our detailed analysis and reasons for our findings on capex are set out in chapter 4, Appendix C and Appendix D.

### 1.5.5 Operating expenditure

Aurora Energy has used the base-step-trend method – commonly used by the Australian Energy Regulatory (AER) and the Commission – to prepare most of its opex forecasts. We consider that this is a valid and reasonable method for forecasting opex, recognising that the underlying premise for it is that the revealed base year includes all efficient costs that a prudent operator would incur. Some of the maintenance, systems operation and network support (SONS) and people costs step changes (above Aurora Energy's RY19 opex) proposed by Aurora Energy we characterise as base year expenditure that a prudent operator would likely incur.

We also consider that most of Aurora Energy's opex forecast does not appear inconsistent with the expenditure objective. However, we consider that Aurora Energy's opex forecast and supporting assumptions for the CPP and review periods do not meet the expenditure objective because:

- Applying a network growth trend to base opex does not appear appropriate for the reactive and corrective maintenance, SONS and people costs programs. Over the CPP and review periods expenditure is either driven by other factors (e.g. defects and faults) that are not immediately affected by network growth or is already factored in (e.g. when establishing new asset management and business support functions). The unverified amount is \$2.5 million for the CPP period and \$5.3 for the review period.
- Some maintenance, SONS and people costs step changes are not fully justified based on the information we have seen. The unverified amounts are \$1.8 million and \$3.1 million respectively over the CPP and review periods across these programs.
- The proposed vegetation management unit rate, which is based on historical costs, appears inefficient when Aurora Energy's vegetation costs are compared to other EDBs. For similar reasons as base maintenance opex, we cannot assume that the RY18 vegetation management costs used to determine that unit rate was efficient. The unverified portion is \$0.8 million and \$0.8 million over the CPP and review periods respectively.

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<sup>17</sup> Note that the gross expenditure is \$5.2 million, which reduces to \$2.1 million once assumed contributions (at 60%) are removed.

These issues are likely to result in expenditure that is too high by up to approximately \$5.0 million over the CPP period and \$9.2 million over the review period,<sup>18</sup> or approximately 3.5% and 4.0% of Aurora Energy's forecast opex respectively. This value is shown in Figure 1.3.

We note that some of the expected benefits resulting from the proposed renewal programs are reflected in assumed efficiencies built into Aurora Energy's corrective and reactive maintenance forecasts for the CPP and review periods. If that renewal expenditure did not happen or was reduced, then the expected efficiencies may also reduce.<sup>19</sup>

We also note that there are interdependencies between the various maintenance expenditure programs. Although Aurora Energy has not necessarily modelled these directly, it did include a forecast step up in corrective maintenance expenditure due to more defects being identified from its proposed increase in proactive maintenance activities. We could not validate whether the two forecasts are entirely consistent with each; however, we do not think that the link is unreasonable in the circumstances.

Finally, we also note that the significant investment in systems, processes and people is likely to lead to productivity improvements, over the CPP and review periods, especially in the later years. Although Aurora Energy has recognised this within its forecasts, these are modest reducing total expenditure by less than 1% over the review period and may be higher in practice.

Our detailed analysis and reasons are set out in chapter 5 and in Appendix C.

### 1.5.6 Deliverability

In our opinion, the work proposed in the capex and opex forecasts over the CPP and review periods does not appear undeliverable, notwithstanding some risks which are discussed below. Aurora Energy has identified these risks and has an appropriately advanced delivery plan across the capex and opex programs. Aurora Energy has largely already secured the resources it needs to deliver the programs; we consider that Aurora Energy will be able to source any additional resources it needs.

Delivery risks could result from:

- management bandwidth and the timeframe to mobilise projects and programs given the significant step up in proposed activity in some areas at the start of the CPP and review periods
- specific assets requiring renewal not yet being identified – this is not unreasonable at this point of time, and is a challenge that has been successfully managed by other networks
- the interplay between the capital and operating program – for example, SONS and people costs being needed to support delivery of the other projects and programs
- some internal resourcing needed is yet to be put in place to give effect to the delivery plan – Aurora Energy is still filling some roles within its SONS and people costs programs, although given that most are filled, this should not be a significant challenge unless the COVID-19 pandemic significantly interferes with recruitment activities for a sustained period
- relatedly, if restrictions in place due to the COVID-19 pandemic endure, then there is a risk that activities planned in the short term need to be deferred – this may undermine delivery over the CPP and review periods, including by creating a backlog of incomplete works
- Aurora Energy potentially awaiting the Commission's final determination before undertaking recruitment and procurement in full – this may result in a risk that some projects or initiatives are not

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<sup>18</sup> The values from above may not sum exactly to these values due to rounding.

<sup>19</sup> However, it is hard to be precise about this potential impact because the assumed efficiencies were based on top-down judgement, rather than a direct mathematical link to the renewal program forecasts.

initiated fast enough to achieve the proposed outcomes over the CPP and review periods. We note that Aurora Energy has indicated it is proceeding with its recruitment plans.

### 1.5.7 Safety and network risks

Safety risks and broader network risk were key drivers of Aurora Energy's CPP proposal. Concern has been raised in recent years about how much safety risk the network carries, including following WSP's review of the state of Aurora Energy's network. To its credit, Aurora Energy has and continues to take action to address this risk, including through many of the proposed expenditure programs included in its CPP proposal.

We were very mindful of these concerns when reviewing the CPP proposal – as it can be quite challenging to link proposed expenditure to specific safety outcomes without looking at the detail sitting behind both the concerns and that expenditure. As safety risk can never be removed entirely from an electricity network, it can also be hard to identify the right level of spending to undertake given the trade-offs involved.

In Aurora Energy's case, these challenges were compounded by its current asset management system<sup>20</sup> and its risk assessment practices – in most instances – not being mature enough to provide a holistic view of the safety risk it faces or determine what level of residual risk it should target. Aurora Energy's corporate policies on health and safety, asset management and risk management framework suggest that it views safety outcomes as a function of the whole of business undertakings. This is an aspirational and holistic view to manage safety risks and requires whole of business management planning, strategies development and implementation, and operational practices that determine the safety outcome in an organisation. Even if its maturity is not there yet, Aurora Energy appears to be on the right path in setting such a view and approaching safety outcomes strategically from the whole of business perspective.

This lack of maturity has made it hard for us to objectively assess what safety risk reduction could be expected from Aurora Energy's proposed expenditure – an important step when assessing whether that expenditure satisfies the 'as low as reasonably practicable' principle.<sup>21</sup> As such, we have utilised expenditure rate and asset performance measure benchmarking (against comparable Australian and New Zealand EDBs) to satisfy ourselves whether Aurora Energy's proposed expenditure is reasonable to address the safety risk it faces, once the safety risk is reasonably established.

We also reviewed Aurora Energy's proposed expenditure for the identified projects and programs against the network risks identified by WSP in its review – and conclude, based on the information provided to us, that that expenditure appears to adequately address the relevant risks identified by WSP.<sup>22</sup> The residual risk levels appear, either explicitly or implicitly, to be consistent with the 'as low as reasonably practicable' (ALARP) principle.

We note the safety and network risks throughout the report, including in Appendix C and Appendix D. We consider network risk in particular in section 6.6 and Appendix F.

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<sup>20</sup> 'Asset management system' refers to the asset fleet strategies, available asset data, ability to harvest information, and asset performance objectives.

<sup>21</sup> The 'as low as reasonably practicable', or ALARP, principle is that the residual risk shall be reduced as far as reasonably practicable.

<sup>22</sup> We considered how Aurora Energy assesses network risks as well as how it proposes to address those risks over the CPP and review periods. This involved comparing Aurora Energy's proposals against WSP's findings and analysis, as well as its maintenance intervals to those adopted by other Australian and New Zealand EDBs. We also considered whether and how the ALARP principle was reflected in the proposed expenditure for each identified asset fleet.

### 1.5.8 Consumer consultation

Aurora Energy has undertaken substantial consumer consultation in preparing its CPP application, and has prepared and made available significant material, consistent with requirements of the IM. Much of this consultation is in line with best industry practice in New Zealand and other jurisdictions, such as Australia. Whilst there are some areas for improvement, we do not believe that they would materially impact Aurora Energy’s overall consumer engagement findings, nor bias its forecasts upwards.

Therefore, we believe that Aurora Energy has complied with the IM consumer engagement requirements for the CPP period.

### 1.5.9 CPP proposal completeness

In assessing Aurora Energy’s capex and opex forecasts, methods, models, and supporting policies, key assumptions and drivers, we have reviewed a significant amount of information prepared by Aurora Energy, including responses to over 450 questions from us.

On the whole, we consider Aurora Energy’s CPP proposal is complete. However, in our detailed findings set out in chapters 3 to 7 we have specified where we consider the information provided by Aurora Energy was incomplete or where information was omitted. We were also not provided with sufficient information to form opinions about the projects and programs that we did not nominate as identified programs (highlighted as ‘not reviewed’ in Figure 1.3 above).

### 1.5.10 Key issues and information requirements

Box 1 sets out the IM requirements for key issues and information requirements.

#### Box 1 – IM requirements for key issues and information requirements

##### Schedule G2(h) of the IM:

Verifier’s role, purpose and obligations include-

...

- (h) providing a list of the key issues which it considers the **Commission** should focus on when assessing the **CPP proposal**.

##### Schedule G12 of the IM:

Based on its assessment, the **verifier** must, in the **verification report**-

- (a) provide a list of the key issues that it considers the **Commission** should focus on when undertaking its own assessment of the information to which the assessment related;
- (b) specify information identified in the **CPP proposal** that, were it to be provided, would assist the **Commission’s** assessment of the **CPP proposal**; and
- (c) identify any other information it reasonably believes would-
  - (i) be held by the **CPP applicant**; and
  - (ii) assist the **Commission’s** assessment of the **CPP proposal**.

We have set out in Table 7.1 in chapter 7.1 the components of the capex and opex forecasts over the CPP and review periods that we suggest the Commission should focus on in assessing and making its determination on Aurora Energy's CPP proposal.

## 2. Background

This section sets out the background to Aurora Energy's CPP, our role as the verifier of the CPP and our approach to verifying the CPP.

### 2.1 VERIFICATION CONTEXT – REASONS FOR AURORA ENERGY'S CPP APPLICATION

Aurora Energy has been subject to default/customised price-quality regulation and information disclosure under Part 4 of the Commerce Act 1986 (the Act) since 2010, but, like most electricity distribution businesses, it has managed the business within the bounds of the default price path (DPP) revenue and has not pursued the option of proposing a CPP until now.

Aurora Energy's needs to submit a CPP are quite different from recent CPPs submitted to the Commission. A key difference relates to Aurora Energy's previous ownership structure, whereby Delta Utility Services Limited (Delta), Aurora Energy's sister company, provided various services including asset management, engineering, network operation and corporate services functions. Delta and Aurora Energy had a common board.

On 1 July 2017, Aurora Energy separated from Delta. As part of the separation, around 100 staff were transferred from Delta to Aurora Energy on 1 July 2017 and from that date Aurora Energy was fully responsible for its governance and operating functions. Delta continues to provide some of Aurora Energy's core maintenance and faults response services under a commercial contract (see sections 4.5 and 5.7 for more detail).

Shortly after the structural separation, it became clear to the new board and management of Aurora Energy that the networks were not performing at the levels expected and that there were unacceptable risks associated with safety and reliability – Aurora Energy was contravening the quality standards (SAIDI and SAIFI) set by the Commission under its DPP determination.

In mid-2018 WSP was engaged by Aurora Energy to undertake an independent review<sup>23</sup> to determine the state of the electricity networks in Dunedin and Central Otago, identifying any critical assets at significant risk of failure. WSP entered a tripartite agreement with the Commission and Aurora Energy to ensure an independent review and to assist the Commission on matters relevant to the review within WSP's area of expertise. The Commission was actively involved throughout the network review including agreeing the terms of reference, approving the choice of consultant, review of interim and draft reports and ensuring the independence of the review.

The objective of WSP's review was to allow interested stakeholders to better assess the appropriateness of Aurora Energy's planned interventions and investments to address safety and reliability concerns. The two key tasks for the review, which reflected a consumer focus, were to:

1. establish an accurate and reliable assessment of the current state of the Aurora Energy networks with particular focus on identified critical assets
2. having established the state of the network, determine the resulting prioritised risk to consumers.

Since the release of the WSP report, Aurora Energy has been addressing the agreed priority findings and regularly updating the Commission on its progress. Aurora Energy will provide a report on its progress

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<sup>23</sup> WSP, Aurora Energy, Independent Review of Electricity Networks, Final Report, 21 November 2018 Report.

addressing the priority recommendations made by WSP by 31 July 2020 and plans to address other findings over the CPP and review periods.

Because Aurora Energy had contravened the quality standards (SAIDI and SAIFI) between 2016 and 2019, on 23 March 2020 the High Court of New Zealand ordered that Aurora Energy pay a pecuniary penalty of \$5 million. Prior to the matter being considered by the High Court, Aurora Energy had accepted the contravention and had discussed the level of penalty with the Commission. Aurora Energy accepted that its conduct in the lead up to 2016 and 2017 meant the contraventions in the 2018 and 2019 periods were virtually inevitable, even though from the end of 2017 Aurora Energy took a number of steps to address its non-compliance from the end of the 2017 Assessment Period onwards.

These steps include:

- initiation and continuing with a major capital works program
- implementing a structural separation of Aurora Energy and Delta effective from 1 July 2017 discussed above
- appointment of a new Board and Chief Executive Officer post structural separation from Delta
- refraining from paying a dividend and drawing on shareholder funding to finance network investment
- undertaking a comprehensive review of its Asset Management Plan through the WSP review discussed above.

In establishing Aurora Energy as a separate entity with appropriate governance and operating capability, and in addressing the agreed priority WSP findings, Aurora Energy's shareholder has funded the shortfall in funds resulting from the necessary expenditure and the revenue under the DPP determined by the Commission. However, with increased expenditure still necessary, Aurora Energy now seeks a price increase to cover the necessary increase in expenditure.

In its consultation publication, *Your Network Your Say*, Aurora Energy states that additional investment is critical to keep its network safe and reliable and to meet the future needs of the communities that it serves. Aurora Energy's reliability has been getting gradually worse in recent years and it needs to continue to invest more than in the past to stop unplanned reliability performance getting worse. Aurora Energy further states that historically it has not spent as much on the network in the past as was needed to keep pace with renewal and growth and that:<sup>24</sup>

*'Aurora Energy's prices have been kept low for many years as a result, among the lowest in the country*

*Staying on the current expenditure allowance (and associated price path) is not an option if we are to meet the community's future needs from their electricity network and meet minimum safety and reliability standards for electricity networks.'*

To address these issues, Aurora Energy's investment priorities are to:

- address the renewal backlog
- deliver a reliable service
- support future growth
- ensure that its networks are safe.

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<sup>24</sup> Aurora Energy, *Your Network Your Say*, November 2019, page 3.

As discussed above, Aurora Energy has already embarked in addressing its deteriorating network performance through a program initially focussed on addressing the priority findings identified in the WSP report.

Material presented to stakeholders for their feedback has been against several key focus areas, proposing what Aurora Energy will do to address the focus area, what it means for a customer and options for further investment. Our role is to verify Aurora Energy's proposed CPP as set out below.

## 2.2 THE VERIFIER'S ROLE AND FOCUS

The verifier's role, purpose and obligations are set out in the IM (see Box 2 below) and focus on capex and opex forecasts with reference to the **expenditure objective**:

*means objective that capital expenditure and operating expenditure reflect the efficient costs that a prudent non-exempt EDB<sup>25</sup> would require to-*

- (a) meet or manage the expected demand for electricity distribution services, at appropriate service standards, during the CPP regulatory period and over the longer term; and*
- (b) comply with applicable regulatory obligations associated with those services.*

The expenditure objective is similar to objectives in other regulatory frameworks, and inevitably relies on judgement in interpreting the attributes and approach associated with a *prudent* business. We do not equate prudent practice with *best practice*, which means that a range of approaches and costs can potentially achieve the expenditure objective.

Good electricity industry practice (GEIP) can be characterised in several ways, with the common theme focusing on the entity satisfying high-level criteria in the management and operation of its network comparable to its peers in the electricity market. By way of example, the Commission has previously commented on its interpretation of GEIP as follows: <sup>26</sup>

*4.12 GEIP provides a useful reference for the sound grid strategies, asset management principles and methodologies that a prudent ... operator could be expected to have in place.*

*4.13 We consider this approach is appropriate as the extent to which ... [the] ... expenditure forecasts are efficient and prudent will depend upon the quality of its asset management framework and the appropriateness of the input assumptions.*

Australia's national electricity regulatory framework defines GEIP as follows:<sup>27</sup>

*The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative*

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<sup>25</sup> Electricity distribution business.

<sup>26</sup> Commerce Commission, *Invitation to have your say on Transpower's individual price-quality path and proposal for the next regulatory control period*, February 2014, p. 22.

<sup>27</sup> National Electricity Rules (Australia), Chapter 10, Glossary.

*size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.*

Similarly, the AER has noted the key components of GEIP to include effective:<sup>28</sup>

*Governance—internal arrangements encompassing reporting lines and supporting systems, including the level of involvement and commitment of senior management and committees, as well as the overall compliance culture of the business.*

*Expertise—the human resources dedicated to technical compliance, including the allocation of responsibilities, the underlying knowledge systems and the nature and extent of the technical understanding of applicable obligations.*

*Implementation—the means by which, at a practical level, participants drive and promote compliance through internal procedures and processes, encompassing staff training, technical testing and reporting of compliance matters.*

*Performance—the overall compliance status of each participant with reference to how effectively compliance programs and arrangements operate, including the ongoing evaluation and updating of such programs and arrangements to reflect lessons learnt.*

In our view, the above definitions are consistent with the regulatory ‘prudency and efficiency’ tests generally applied by the Commission and Australian economic regulators. In simple terms, *prudency* relates to expenditure directed to maintaining the safety, quality, reliability and security of supply of regulated services. *Efficiency* relates to the provision of regulated services in a least cost manner having regard to conditions in relevant markets for labour, capital and materials inputs.

These definitions contrast with the concept of best practice, which relates more to an entity working at the frontier for policies and procedures and the like.

In our review of Aurora Energy’s CPP proposal, we have used each GEIP definition in various ways:

- reviewed asset management systems and practices – GEIP as defined by the Commission
- used benchmarking with industry peers – GEIP as defined within the Australian National Electricity Rules
- reviewed how Aurora Energy has applied governance, expertise and implemented the CPP proposal – GEIP as interpreted by the AER in assessing key components.

In some cases, we have used all three, and for some cases where appropriate, a subset.

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<sup>28</sup> AER, Generator Performance Standards Information Booklet August 2013

## Box 2 – Verifier’s role, purpose and obligations<sup>29</sup>

### Schedule G2 of the IM:

The **verifier’s** role, purpose and obligations include-

- (a) engaging with the **CPP applicant** in an **independent** manner in accordance with this Terms of Reference;
- (b) assessing the extent to which the **CPP applicant’s policies** allow the **CPP applicant** to meet the **expenditure objective**;
- (c) assessing the extent to which the **CPP applicant’s policies** have been implemented;
- (d) prior to the **Commission’s** assessment of the **CPP proposal**, assessing whether the **CPP applicant** has provided the **verifier** with the information specified in clause 5.5.2(3);
- (e) prior to the **Commission’s** assessment of the **CPP proposal**, providing an opinion to the **CPP applicant** on whether the **CPP applicant’s capex forecasts, opex forecasts and key assumptions** meet the **expenditure objective**;
- (f) prior to the **Commission’s** assessment of the **CPP proposal**, assessing the extent to which the **CPP applicant** is able to deliver its **capex forecast and opex forecast** during the **CPP regulatory period**;
- (g) prior to the **Commission’s** assessment of the **CPP proposal**, providing an opinion on the extent and effectiveness of the **CPP applicant’s** consultation with its **consumers**; and
- (h) providing a list of the key issues which it considers the **Commission** should focus on when assessing the **CPP proposal**.

## 2.3 APPROACH AND PROCESS FOR VERIFYING AURORA ENERGY’S CPP

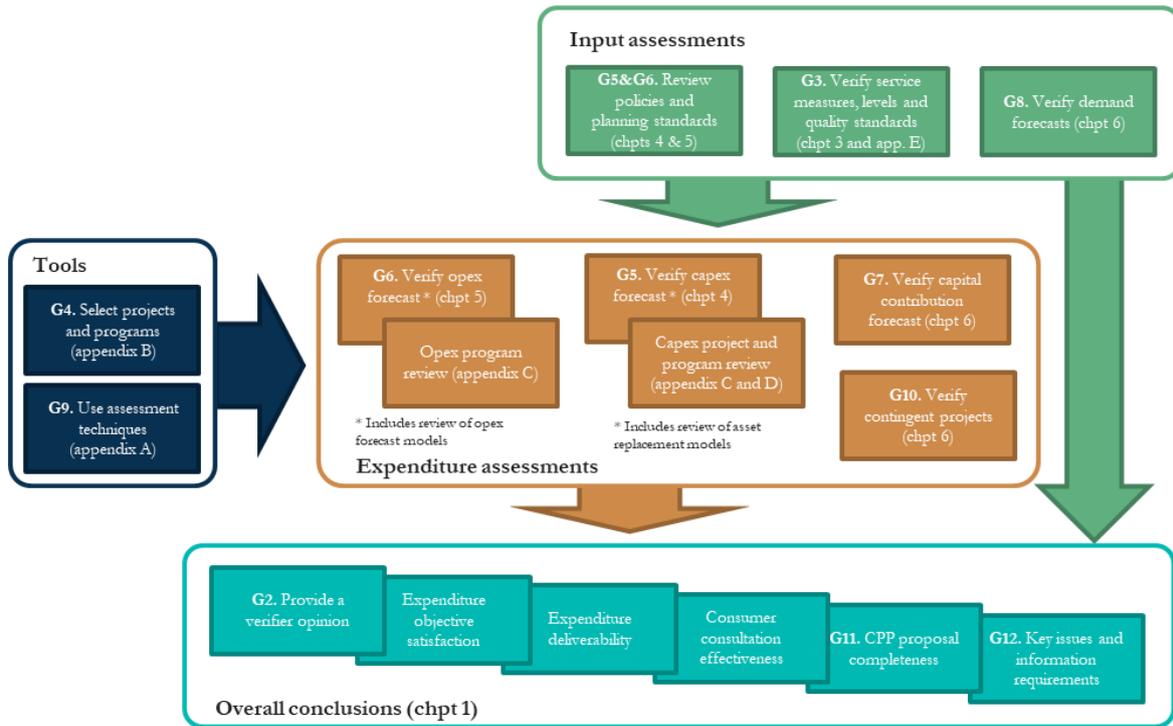
The opinions and advice set out in this report draw on an eleven-month period of information review and iterative analysis. To a large part, the verification process has occurred in parallel with Aurora Energy’s work to develop and refine its CPP application before this is submitted to the Commission. At the time of writing this report, Aurora Energy continues to finalise that application.

Our involvement commenced on 3 July 2019 when farrierswier and GHD (sub-contractors to farrierswier) attended a tripartite workshop with Aurora Energy and the Commission. A SharePoint site was established in late August 2019, and since then we have been provided with a significant number of documents, including plans, policies, spreadsheets and expert reports. We conducted site visits to Aurora Energy’s Dunedin offices and wider network assets in July 2019, December 2019 and March 2020. In March 2020 a weeklong series of workshops were conducted where farrierswier and GHD Australian located members attended by teleconference due to travel restrictions imposed by the Australian and New Zealand governments dealing with COVID-19.

We also attended over 10 monthly tripartite meetings with Aurora Energy and Commission staff in Aurora Energy’s Dunedin and Wellington offices or remotely. In addition, in accordance with the communication protocols, we have formally directed many questions and information requests to Aurora Energy, which resulted in over 450 responses from Aurora Energy.

<sup>29</sup> In this box – and other boxes throughout the report – bolded text represents defined terms included within the IM.

Figure 2.1 – Overall approach to verification



Our approach to verification is shown in Figure 2.1 and was specifically designed to meet the IM requirements. This included nominating up to 18 selected projects and programs for detailed review (see Appendix B and Appendix C) and applying a range of assessment techniques (see Appendix A) to assess the CPP proposal and supporting information (see Appendix I), including benchmarking (see Appendix G), trend analysis, desktop reviews, interviews, and model critiques (for instance, see Appendix E).

## 2.4 STRUCTURE OF OUR REPORT

Our report is structured as follows:

Heading	Sets out
Chapter 3	Findings on services measures, service levels, consumer engagement and quality standard variations
Chapter 4	Findings on Aurora Energy’s forecast capex
Chapter 5	Findings on Aurora Energy’s forecast opex
Chapter 6	Findings on other matters that we are required to consider including demand, contingent projects and cost escalation
Chapter 7	Findings on completeness of the CPP proposal
Appendices	Supporting analysis and information, including on benchmarking, and our detailed review of projects and programs and the reliability modelling Our nomination of selected projects and programs (G4 IM) and the assessment techniques (G9 IM) that we used and the information that we relied on as part of our verification

## 3. Service measures, levels and quality standards

Aurora Energy is proposing four service measures – planned and unplanned SAIDI and planned and unplanned SAIFI.<sup>30</sup> These are the same measures that apply currently under Aurora Energy’s DPP for the 2020–25 period.

Aurora Energy is also proposing quality standard variations to:

- increase the unplanned SAIFI limit from 1.4687 to 2.5067 interruptions
- increase the unplanned SAIDI limit from 81.89 to 146.29 minutes.

Aurora Energy is not proposing changes to the planned SAIFI or SAIDI DPP3 limits, nor any changes to the quality incentive scheme that we are aware of (apart from the update to the unplanned SAIDI limit).

This chapter assesses these proposals against the IM requirements, including by assessing how Aurora Energy has consulted with its consumers about its proposal.

This chapter is structured as follows:

Heading	Sets out
Section 3.1	Findings on Aurora Energy’s service measures
Section 3.2	Findings on Aurora Energy’s service levels
Section 3.3	Findings on Aurora Energy’s consumer engagement
Section 3.4	Findings on Aurora Energy’s proposed quality standard variation

### 3.1 SERVICE MEASURES

#### 3.1.1 Aurora Energy’s proposal and our general observations

Aurora Energy’s current DPP includes planned and unplanned SAIDI and SAIFI limits that it must meet, with the split between planned and unplanned recognising that interruptions may be caused by a planned activity – such as replacing a power line or undertaking vegetation management – or an unplanned event – such as from a tree falling on a power line during a storm. Both components are important to consumers as both affect the service outcomes that they experience.

Aurora Energy proposes to retain the same service measures as part of its CPP and the same structure for how they are used to set quality standards. These measures are important given Aurora Energy’s proposal to stabilise deteriorating network condition and performance by rectifying historical underinvestment in the network and renew aging assets, and the outcomes that follow from this, such as reliability and safety. However, Aurora Energy proposes to replace the forecasts for those measures – which the Commission

<sup>30</sup> SAIDI is the system average interruption duration index and measures the average length of outages per consumer for a given period (e.g. a year), while SAIFI is the system average interruption frequency index and measures the average number of outages per consumer for a given period.

had based on historical averages when setting the DPP – with those that better reflect its projected performance of the network.

Aurora Energy has also actively consulted with its consumers and other stakeholders on the service attributes that they find important and meaningful.<sup>31</sup> Reliability is one of these service attributes. Although other service attributes were also identified as important and meaningful by consumers, Aurora Energy is not proposing additional service measures to address these in its CPP due to:

- consumers voicing a strong preference to focus on avoiding spending beyond what is needed to stabilise reliability and safety outcomes,<sup>32</sup> and
- it already committing to guaranteed service levels for:
  - notification of planned power outages
  - restoration of electricity services, and
  - investigation of power quality complaints
 where Aurora Energy refunds network charges to consumers – referred to as ‘charter credits’ – where these levels are not met.<sup>33</sup>

### 3.1.2 IM requirements and our approach to assessment

This section aims to address Schedule G3(1)(a) and (b) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 3 – IM requirements for service measures

##### Schedule G3 of the IM:

- (1) The **verifier** must review, assess and report on-
  - (a) whether the **CPP applicant** has proposed **service measures** relevant to a complete range of key service attributes that are meaningful and important to **consumers**;
  - (b) whether the **CPP applicant** has undertaken an appropriate process to determine the **service measures** and **service levels**, such as consultation with relevant **consumers**;

Our approach to assessment was:

- identify a complete range of key service attributes that are meaningful and important to consumers, including by looking at consumer feedback received by Aurora Energy
- compare Aurora Energy’s proposed service measures against these service attributes to identify whether all attributes are covered
- review the process that Aurora Energy undertook to determine its proposed service measures.

Relevant information provided by Aurora Energy is set out in Table 3.1.

<sup>31</sup> We, for instance, attended Aurora Energy’s customer advisory panel session held on 13 August 2019 in Dunedin that covered customer service and reliability, including an exercise where panel members ranked 28 potential service initiatives by importance.

<sup>32</sup> For example, Customer Advisory Panel response to Aurora Energy CPP consultation document, December 2019, paragraph 12.

<sup>33</sup> Aurora Energy, *Customer Charter*, 1 July 2017, section 7.

Table 3.1 – Information provided – service measures

Title	Reference	Date
QS00 - CPP Quality Standards Explanatory Memo	E-73	6 March 2020
P03 - Reliability and Service Levels v1.1	V-134	27 March 2020
Customer Advisory Panel response to Aurora Energy CPP consultation document	IP2-94	29 January 2020
Standard Use-of-System Agreement	IPL-760	4 December 2019 (provided) 1 April 2014 (dated)
Aurora Energy Customer Charter	IPC-979	29 November 2019 (provided) 1 July 2017 (dated)

### 3.1.3 Our findings

The proposed service measures are relevant to key service attributes that appear meaningful and important to Aurora Energy’s consumers. This is evidenced by consumer feedback that reliability is important and that current levels should be maintained.<sup>34</sup>

However, the proposed service measures do not cover a complete range of key service attributes that are meaningful and important to consumers. This is because consumers have also said that they consider other service attributes are important to them, including safety, improving new connections and better information during outages.

Consistent with a key driver for Aurora Energy’s CPP proposal, consumers made clear that safety should be a top priority.<sup>35</sup> This begs the question of whether Aurora Energy should adopt one or more safety related service measures in addition to those retained for reliability. Although lack of reliable data and difficulty in identifying the right safety measures are likely to make this challenging, we recommend that this is explored further through the CPP process (e.g. by including one or more safety measures in the AMP or other annual reporting mechanism).<sup>36</sup> Doing so will allow Aurora Energy and its consumers to monitor the effect that the significant investment proposed actually has on safety outcomes. Although not reviewed by us, we understand that Aurora Energy’s 2020 AMP will include safety targets for ‘TRIFR’ and ‘zero harm to the public’ and continued tracking of improvements to safety system audits.

The process undertaken by Aurora Energy to determine the proposed service measures appears appropriate in the circumstances because Aurora Energy:

- started with the service measures approved by the Commission in the DPP – which was itself subject to public consultation and is consistent with previous regulatory determinations

<sup>34</sup> For example, Customer Advisory Panel response to Aurora Energy CPP consultation document, December 2019; Aurora Energy’s phone survey conducted by UMR during December 2019 and January 2020 indicated high level of satisfaction with current reliability of power supply (86%). See also Aurora Energy’s Response to Independent Verifier on consultation evidence to support proposed quality measures, 28 April 2020.

<sup>35</sup> See, for instance: Consumer Advisory Panel, *Customer Advisory Panel response to Aurora Energy CPP consultation document*, January 2020, paras. 3 and 15. See also Aurora Energy’s Customer feedback on safety investment for independent verifier, 5 May 2020, page 4.

<sup>36</sup> Specific examples are identified in Appendix D.

- engaged with consumers about what service attributes they consider important – and reliable electricity supply was consistently identified along with improved safety outcomes
- also recognised that its guaranteed service levels provide for monitoring of individual service outcomes – which acts as an alternative to having those outcomes reflected in quality standards.

### 3.1.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on its proposed service measures was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As noted above, we recommend that the Commission and Aurora Energy consider further what, if any, safety related service measures should be included as a reporting requirement over the CPP period. We have not identified any other key issues relating to the proposed service measures that we consider the Commission should focus on when undertaking its own assessment of the information.

## 3.2 SERVICE LEVELS

### 3.2.1 Aurora Energy’s proposal and our general observations

Aurora Energy forecasts that planned SAIDI and SAIFI will continue at elevated levels over the CPP and review periods relative to current levels although not to a level requiring any proposed changes to the current DPP3 limits.

Aurora Energy also forecasted that unplanned SAIDI and SAIFI are expected to be higher over the CPP and review periods than the targets reflected in the DPP for the 2020–25 period and proposes that the quality standard limits for both should be increased accordingly – as shown in Figure 3.2.

Our alternative forecasts (referred to in the figures as ‘TV Model’) suggest that:

- planned reliability could be slightly worse than proposed by Aurora Energy, but still within the annualised DPP3 limits for the CPP and review periods
- unplanned reliability could be better than that proposed, but – consistent with Aurora Energy’s forecasts – above the annualised DPP3 limits.

Our forecasts and review of Aurora Energy’s forecasts are detailed in Appendix E.<sup>37</sup>

Importantly, our alternative forecasts were developed for comparative purposes only to help us identify aspects of Aurora Energy’s modelling that may or may not be appropriate. We did not develop these alternative forecasts to substitute for those developed by Aurora Energy and may not be suited to that purpose.

When preparing these alternative forecasts, we recognise that:

- different modelling approaches can be used to generate reasonable forecasts of planned and unplanned reliability for an EDB – and none can perfectly predict future outcomes<sup>38</sup>

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<sup>37</sup> We understand that Aurora Energy is continuing to consider refinements to its unplanned reliability modelling, including to address points raised in our final verification report. We recommend that the Commission engage further with Aurora Energy on its unplanned reliability modelling.

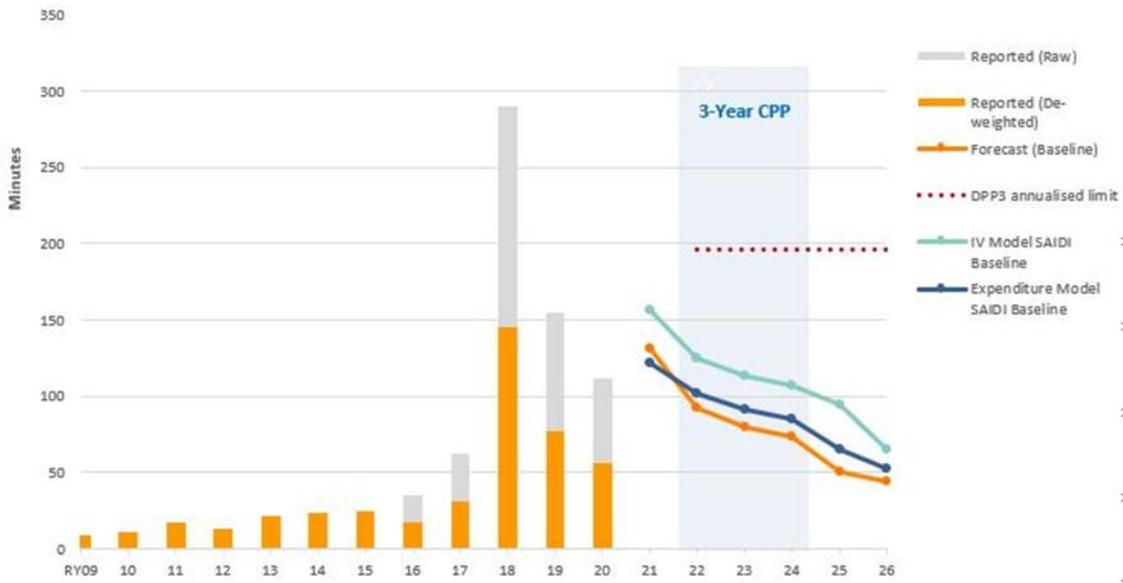
See: Aurora Energy, *Memo from Glenn Coates to Eli Grace-Webb – Re: Reliability Forecasts*, 4 June 2020.

<sup>38</sup> Reliability forecasting is complex. Different statistical approaches can reasonably be used, which may lead to a range of plausible forecasts. Comparing forecasts from different methods can help identify differences between the methods and any appropriate adjustments that should be made to them.

- Aurora Energy’s reliability performance over recent years is not in a steady state – and so simplified modelling based on that history may not accurately predict future outcomes.

Figure 3.1 – Planned SAIDI and SAIFI

**Planned SAIDI**



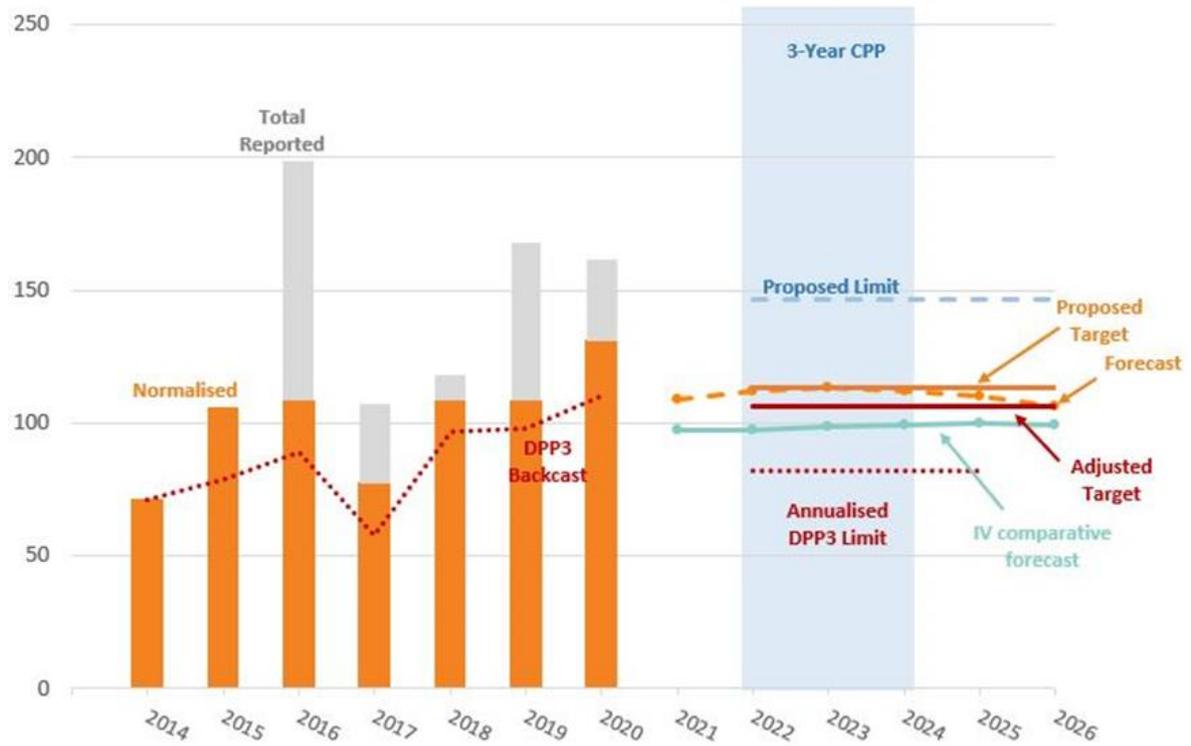
**Planned SAIFI**



Source: Aurora Energy, planned reliability model ('Aurora-model-forecast-planned-SAIDI-SAIFI v5.01'), farrierswier and GHD analysis

Figure 3.2 – Unplanned SAIDI and SAIFI

Unplanned SAIDI



Unplanned SAIFI



Source: Aurora Energy, unplanned reliability model ("QS02 - Unplanned Reliability Forecast Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11"), farrierswier and GHD analysis.

- (a) The proposed targets and limits should be compared with the dotted line covering the RY09 to RY20 period, which reflects the new approach to measuring outages adopted for the DPP for the 2020–25 period.
- (b) The ‘Adjusted Target’ shown in each chart reflects updates that we made to Aurora Energy’s forecasts to align the normalisation with the estimated parameters.

### *Planned reliability*

Aurora Energy’s proposed increases in planned SAIDI and SAIFI levels are material and reflect the significant increase in asset renewal, maintenance and vegetation management activity proposed for the CPP and review periods (discussed in chapters 4 and 5). Aurora Energy forecasts each in two different ways:

- the *first* method forecasts planned SAIFI and SAIDI for each fleet category by linearly regressing the relationship between forecast replacement volumes and contributions to the number of outages, the number of customers interrupted and the duration, aggregating the respective modelled contributions
- the *second* method forecasts planned SAIFI and SAIDI by linearly regressing renewal expenditure against actual data from RY14 to RY20, and then applied to forecast expenditures for each asset category over the review period.

The outcomes from both methods were averaged to derive the pre-weighted planned SAIDI and SAIFI forecasts.

An adjusted forecast was applied to planned SAIDI that reflects improving notification compliance over the review period (starting at a 10% reduction in reported SAIDI in RY21 and increasing to 40% by RY26).<sup>39</sup> Planned SAIFI was also adjusted down to incorporate forecast efficiency gains from planned outage coordination (starting at 0% in RY21 and increasing to 15% in RY26).

The method and approaches used are generally not unreasonable. However, as discussed further in Appendix E and section 3.2.3, the forecasting approaches for planned SAIDI and SAIFI, as applied, both appear to understate forecasts, particularly planned SAIFI. Our adjusted baseline targets, based on this review, have been overlayed in Figure 3.1.

Aurora Energy provided a further revised model (v5.05) with an explanatory note with limited available time for us to fully review these changes. We were still not convinced that Aurora has adequately addressed these concerns and our view is that the model still understates the forecasts for planned reliability over the CPP period. This is further discussed in the findings in section E.5.6.

### *Unplanned reliability*

Aurora Energy’s proposed forecasts for normalised unplanned SAIDI and SAIFI will increase from current levels, particularly for unplanned SAIFI, over the CPP and review periods. However, we would expect that the significant increases in the past and forecast capex and opex – targeted at activities that will reduce the frequency and duration of unplanned outages – would have a positive and noticeable impact on normalised unplanned SAIDI and SAIFI.<sup>40</sup> Expenditure on critical fleets such as distribution conductors has only just begun to ramp up as pole expenditure declines.

The method and approaches used in forecasting unplanned SAIDI and SAIFI appear valid, except for the applied normalisation factors and potentially unknown factors regarding the recent updated RY20 data.

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<sup>39</sup> Aurora Energy advised that to achieve these gains it would need to improve its planned outage notification accuracy from 20% to 80%.

<sup>40</sup> Although there is a slight reduction in forecast unplanned SAIDI, this largely reflects just the forecast improved health of distribution conductors.

We discuss our concerns in detail in Appendix E and further with respect to the findings in section 3.2.3. Our adjusted targets, based on this review, have been overlayed in Figure 3.2.

### Consultation

Aurora Energy consulted with consumers on its proposed service measures and levels. Customers stated that Aurora Energy’s current reliability should be maintained and did not support improvement or reduction to existing service levels, especially given concerns about price implications.<sup>41</sup>

### 3.2.2 IM requirements and our approach to assessment

This section aims to address Schedule G3(1)(b) and (c) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 4 – IM requirements for service levels

**Schedule G3 of the IM:**

(1) The **verifier** must review, assess and report on-

...

(b) whether the **CPP applicant** has undertaken an appropriate process to determine the **service measures** and **service levels**, such as consultation with relevant **consumers**;

(c) whether any step change in any **service level** is explained and justified;

Our approach to assessment was to:

- identify what service levels are proposed by Aurora Energy for the CPP and review periods, including any step changes
- review the explanation and justification for any step changes relative to current levels
- consider whether there should be a step change relative to current levels where none was proposed
- review the method and model used to forecast the planned reliability service levels
- review the method and model used to forecast the unplanned reliability service levels
- consider what, if any, impact the proposed expenditure for the CPP and review periods may have on planned and unplanned SAIDI and SAIFI over those periods
- review the process that Aurora Energy undertook to determine its proposed service measures.

Relevant information provided by Aurora Energy is set out in Table 3.2. We reviewed documentation and models over two stages – at the draft report stage and then at the final report stage. While the initial documents have been superseded, they have information still relevant to the models and forecasts in the revised models.

**Table 3.2 – Information provided – service levels**

Title	Reference	Date
QS00 - CPP Quality Standards Explanatory Memo	E-74	6 March 2020

<sup>41</sup> Aurora Energy, CPP Customer Engagement Verifier Workshop presentation, 20 March 2020, slide 20.

Title	Reference	Date
QS01 - Planned Reliability Forecast	E-72	6 March 2020
QS02 - Unplanned Reliability Forecast	E-73	6 March 2020
P03 - Reliability and Service Levels v1.1	V-134	27 March 2020
Planned Methodology Technical v1.0	V-132	27 March 2020
planned-SAIDI-SAIFI model v4.8	V-130	27 March 2020
Modelling_Assumptions_Planned_v4	V-131	27 March 2020
Concept Explanation of unplanned Reliability_Approach_v04	V-135	27 March 2020
Category mapping from expenditure forecast to reliability ( <i>sic</i> ) forecast 27MAR	V-136	27 March 2020
Python_Code_Planned	V-129	27 March 2020
<b>Provided in response to our draft report</b>		
Aurora-model-forecast-planned-SAIDI-SAIFI v5.01	PR-57	6 May 2020
200513 Unplanned forecast memo	PR-69	14 May 2020
Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11	PR-68	14 May 2020
equip_deterioration_v1.1	PR-66	14 May 2020
equip_deterioration_v1.1.py	PR-67	14 May 2020
Aurora-model-forecast-planned-SAIDI-SAIFI v5.05	PR-77	20 May 2020
Memo Responding to Reliability Penultimate Draft Feedback.docx	PD-3	1 June 2020
Memo Regarding CPP Application Quality Standard	PD-12	4 June 2020

### 3.2.3 Our findings

#### Planned SAIDI and SAIFI

In general, the proposed step changes to planned SAIDI and SAIFI service levels are well explained in the documents provided to us and appear justified (in terms of direction), provided that the increase in renewal, maintenance and vegetation management activity is also justified and the increase in those levels reduces if and when the increase in activity subsides.<sup>42</sup> It is reasonable to assume that a material step up in this type of activity will lead to more planned outages.

<sup>42</sup> As noted above, Aurora Energy's consumers indicated that they expect a safe network and that investment to address safety will also arrest further decline in unplanned outage performance. Based on its consultation, Aurora Energy concluded that consumers generally understood and accepted that more planned outages were needed to undertake renewal and maintenance work.

The key exception is that the planned step change in SAIFI – and to a lesser extent SAIDI – appears understated to us because: <sup>43</sup>

- the historical expenditure and volume data were not adjusted to account for pole reinforcements that cause costs, but not outages<sup>44,45</sup>
- the regression analysis – particularly that used in the volumes method – does not appear to be producing valid results for asset contributions as the ratios of forecast SAIFI to CAIDI to renewal volumes or expenditure is not constant over the forecast period<sup>46,47</sup>
- the expenditure and renewal model does not consider planned outages from corrective maintenance (either in terms of volumes or expenditure) – which may impact how the regression models treats the high storm damage year of RY18 through into the forecasts
- the step change in crossarm renewals (including a dedicated program) is unlikely to be accurately captured by the regression analysis given that the historical data used to estimate the regression parameters did not include many crossarm renewals – our alternative modelling suggests that forecast planned SAIFI is very sensitive to the average number of crossarms to be replaced per outage event. <sup>48</sup>

Our alternative modelling suggests that:<sup>49</sup>

- that the average planned SAIDI over the CPP and review periods (after notification compliance and before efficiencies are factored in) should be higher – around 115.1571 and 101.1218 minutes per annum respectively, compared to 81.7735 and 67.9259 proposed by Aurora Energy
- the average planned SAIFI over the CPP and review periods (after notification compliance and efficiencies are factored in) should have a frequency higher – around 1.03 and 0.92 per annum respectively, compared to 0.63 and 0.53 proposed by Aurora Energy.

Apart from these exceptions, the modelling methods used by Aurora Energy to quantify these step changes do not appear unreasonable or inadequate. They appear to reflect the forecast change in the volumes of work. *If* the findings in our review are considered, then the outcomes could be reflected appropriately through adjustments to the Aurora Energy data inputs.

Appendix E provides our further analysis of Aurora Energy’s forecast planned SAIDI and SAIFI.

### Unplanned SAIDI and SAIFI

In our view, Aurora Energy’s proposed unplanned normalised SAIDI and SAIFI service levels appear overstated based on the modelling assessed and information provided. However, we agree with Aurora Energy that the DPP3 targets for unplanned reliability are too low.

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<sup>43</sup> With respect to model version Aurora-model-forecast-planned-SAIDI-SAIFI v5.01.

<sup>44</sup> In our view, adjustments are needed to the expenditure and volumes in the historical pole replacement data to recognise pole reinforcement. Outages are generally not required for pole reinforcement and a high proportion of pole renewal over the last four years related to pole reinforcement. Unless adjusted for, regressing historical outages against expenditure is likely to understate planned outages required over the CPP and review periods given that Aurora Energy is proposing not to continue the practice over those periods.

<sup>45</sup> As noted in Appendix E, Aurora Energy has adjusted for the expenditure in v5.05 of its planned reliability model. Our limited review of that version indicates that pole volumes may not have been removed. However, we were unable to confirm the input changes in the revised model.

<sup>46</sup> Those ratios effectively represent the mean values for each parameter involved.

<sup>47</sup> Although forecast CAIDI appears steady in aggregate across the unplanned reliability forecasts, it does not when looking at individual asset contributions.

<sup>48</sup> This matter appears to have been resolved in the unplanned reliability model v5.05.

<sup>49</sup> The values identified for Aurora Energy are taken from v5.01 of its planned reliability model. Aurora Energy’s subsequent version of the model (v5.05) leads to slightly different values for planned SAIDI over the CPP and review periods.

We expect that the net effect of the proposed capex and opex will lead to arresting the past increases in unplanned pre-normalised SAIDI and SAIFI – including because the operating initiatives are moving Aurora Energy to a more proactive than reactive approach to managing faults and risk and giving it more scope to resolve faults quicker (e.g. with a 24/7 response service).

Our view on the unplanned SAIDI and SAIFI service levels is based on the following observations:

- With the absence of a significant growth driver, most capital projects and programs are expected to improve service measures and levels, including reliability. Aurora Energy’s modelling appears to suggest that recent past, current and future proposed renewal programs will not begin to arrest a worsening reliability performance until after the CPP period, which our modelling supports.
- The information provided for several programs states that there would be reliability benefits following completion of the work. However, these do not appear to be reflected in the reliability forecasts, for example from the past pole replacement program. Such reliability benefits should be realised as work programs are rolled out; however, we acknowledge that other offsetting factors such as general aging of other assets will also have an impact and may be material for some fleets.
- Aurora Energy’s proposed maintenance approach is moving to focus on corrective and preventative maintenance that should result in reliability benefits. These benefits have not been quantified in the information provided. Identifying and rectifying defects, even when not priority defects, will avoid many of them becoming reliability issues. At the same time, Aurora Energy’s proposal to establish a 24/7 fault response dispatch service should reduce fault restoration times after hours. This expenditure should therefore lead to improved reliability relative to current levels.
- Aurora Energy’s proposed vegetation management approach should reduce the number of unplanned outages due to vegetation (as acknowledged in response to RFI D281). However, our analysis in Appendix E shows that historically a reduction in unplanned SAIFI has not resulted in decreasing SAIDI for vegetation related events as average outage durations are longer when events occur.
- The revised model appears to overstate target unplanned SAIDI and – more so – unplanned SAIFI when compared to our alternative forecasts – and this may be due to how the normalised factors used to convert the pre-normalised forecasts to normalised forecasts were determined from historical data. If, for instance, the forecast normalisation factors were calculated as the ratio of historical pre-normalised data to DPP3 normalisation backcast data, then the unplanned reliability forecasts appear to reduce noticeably relative to those provided by Aurora Energy’s forecasts.

While findings from our review of the draft model were addressed by Aurora Energy in its revised model, changes made to the regression analysis now strongly result in a weighted emphasis on the last three years (RY18 to RY20).<sup>50</sup> When reliability is deteriorating, more recent performance data will have greater relevance when forecasting unplanned reliability – which is consistent with Aurora Energy using data from RY18 to RY20 to estimate the parameters. However, the period used to estimate the normalisation factors applied to the pre-normalised forecasts should be the same as that used to estimate the regression parameters to ensure that they are consistent.

Our alternative forecasts suggest that:

- normalised unplanned SAIDI over the CPP and review periods should be 106.1 minutes per year – compared to 110.7 proposed by Aurora Energy
- normalised unplanned SAIFI should be 1.70 outages – compared to 1.94 proposed by Aurora Energy.

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<sup>50</sup> Aurora Energy’s revised forecasts are strongly influenced by the average unplanned SAIFI and SAIDI network performance over the RY18 to RY20 period. Our alternative forecasts were calibrated to the RY14 to RY20 period – and therefore were less influenced by the recent high RY20 unplanned SAIDI outcome.

If Aurora Energy's forecasts are adjusted to remove the inconsistency, then they are reasonably consistent with our alternative forecasts.

Appendix E provides our further analysis of Aurora Energy's forecast normalised unplanned SAIDI and SAIFI.

### 3.2.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on its proposed service measures was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

We do, however, consider that the Commission should focus on the relationship between Aurora Energy's proposed expenditure forecasts and the impact on reliability when undertaking its own assessment of the information. Most customers have clearly said that they do not want to pay for improved reliability.<sup>51</sup>

As noted above, in our view, Aurora Energy's past and proposed expenditure should arrest the decline in reliability performance earlier than forecast by Aurora Energy. That view, however, is subject to limitations as:

- modelling unplanned SAIDI and SAIFI is inherently difficult – as further discussed in Appendix E
- although changes in asset health was used in Aurora Energy's modelling, our alternative modelling used reliability failure rates defined in the program renewal models rather than regression analysis methods (used by Aurora Energy)
- our alternative model is only based on the key contributing asset categories (conductors, crossarms and poles) with variation due to weather impacts discounted by us using the historical normalised data (DPP3 backcast).

The Commission may wish to consider the following when undertaking its own assessment of Aurora Energy's unplanned reliability forecasts:

- whether preventative maintenance and corrective maintenance have been incorporated into the unplanned normalised reliability model adequately
- how the pre-normalised reliability forecasts might relate to future normalised reliability, given that Aurora Energy's model is weighted to RY18 to RY20 which could be overweighted to bad weather years rather than, say, over the longer DPP2 period (RY16 to RY20)
- why the unplanned SAIFI outcome for RY20 was relatively high and what this says about unplanned SAIFI over the CPP and review periods
- how much of the general aging of the network and any major events resulting from aging substation fleet will offset the benefits of recent past, current, and future renewal programs
- Aurora Energy's reliability performance over recent years, noting that:
  - normalised unplanned SAIDI and SAIFI appeared to flatten over recent years except for the recent RY20 performance, which has increased markedly – and so this provides a useful starting point for assessing how it might evolve if the proposed renewal and maintenance expenditure is made
  - initiatives undertaken over RY18 to RY20, such as the accelerated poles program, are likely to have helped stabilise reliability to a degree – which appears to be understated in Aurora Energy's

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<sup>51</sup> Aurora Energy, CPP Customer Engagement Verifier Workshop presentation, 20 March 2020, slide 20.

regression analysis compared to what historical data would suggest (refer Appendix E for further details)

- the change of vegetation strategy may have a downward contribution to unplanned SAIFI but not to unplanned SAIDI
- whether the contributions forecast for crossarms, poles, and conductors due to changing asset health are reasonable in comparative contribution and change over the review period.

The Commission may wish to consider the following when undertaking its own assessment of Aurora Energy’s planned reliability forecasts:

- while the approach to forecasting planned SAIDI and SAIFI in the ‘planned-SAIDI-SAIFI model v5.01’ model is valid, it does not appear to be producing results that we would expect through our alternate modelling – our view is that there may be input data errors resulting in understatement of the likely planned SAIFI and SAIDI reliability outcomes
- our analysis though does not increase the forecasts to a point where the annualised DPP3 planned reliability limits would need changing, hence the degree of further consideration can be considered accordingly
- Aurora Energy provided a further update to its planned reliability model (v5.05), which we have only briefly been able to review in the time available for this final report – in our view the updated forecasts still appear to understate the likely planned reliability performance due to input errors related to the historical pole reinforcements, the volumes being counted in the historical data but for outages that were not required.

### 3.3 CONSUMER CONSULTATION

#### 3.3.1 Aurora Energy’s approach and our general observations

Aurora Energy has undertaken substantial consumer consultation, and has prepared and made available material, consistent with clause 5.5.1 of the IM. Aurora Energy’s approach to consultation is in line with precedents set by other New Zealand networks recently seeking a CPP and is consistent with consultation undertaken by other network businesses in other jurisdictions, such as Australia.

Table 3.3 presents a high-level overview of the information that has been provided by Aurora Energy in relation to consumer consultation. Appendix A lists the documents that we have reviewed.

**Table 3.3 – Information provided – consumer consultation**

Title	Reference	Date
Your Network, Your Say	IP-1271	November 2019
Type of Policy / Standard / Strategy – Consultation – Materials Presented / Published (48 artefacts)	IP-1254 to IP-1267, IP-1268 to IP-1320	12 December
Type of Policy / Standard / Strategy – Consultation – Strategy (4 artefacts)		
Type of Policy / Standard / Strategy – Consultation – Survey findings / customer research (15 artefacts)		
Customer Advisory Panel response to Aurora Energy CPP consultation document	IP2-94	29 January 2020

Title	Reference	Date
<b>Provided in response to our draft report</b>		
Consult Diagrams v06-09.png	PD-7	2 June 2020

### 3.3.2 IM requirements and our approach to assessment

This section aims to address the IM requirements for consumer consultation set out in Schedule G2(g) and G3 of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements. Schedule G3(d) requires verification of the extent and effectiveness of a CPP applicant’s consultation with its consumers, as specified in clause 5.5.1 of the IM.

#### Box 5 – IM requirements for consumer consultation

##### Schedule G2(g) and G3, and clause 5.5.1 of the IM

###### Schedule G2:

The **verifier’s** role, purpose and obligations include-

...

- (g) prior to the **Commission’s** assessment of the **CPP proposal**, providing an opinion on the extent and effectiveness of the **CPP applicant’s** consultation with its **consumers**.

###### Schedule G3:

(1) The **verifier** to review, assess and report on:

...

- (d) the extent and effectiveness of a **CPP applicant’s** consultation with its **consumers**, as specified in clause 5.5.1 of the IM.

###### Clause 5.5.1:

(1) By no later than 40 **working days** prior to submission of the **CPP proposal**, the **CPP applicant** must have adequately notified its **consumers**-

- (a) that it intends to make a **CPP proposal**;
- (b) of the expected effect on the revenue and quality of its **electricity distribution services** were the **Commission** to determine a **CPP** entirely in accordance with the intended **CPP proposal**;
- (c) of the price versus quality trade-offs made in the expenditure alternatives considered in the intended **CPP proposal**, where these are directly associated with the rationale for seeking the **CPP proposal**, which are required to be disclosed under clause 5.4.2<sup>52</sup>;
- (d) if it intends to propose to include a **quality standard variation** under clause 5.4.5, why the proposed **quality standard variation** has been chosen over alternative quality standards;

<sup>52</sup> A CPP proposal must contain a (a) detailed description of the CPP applicant's rationale for seeking a CPP; and (b) summary of the key evidence in the proposal supporting that rationale.

- (e) where and how further information in respect of the intended **CPP proposal** may be obtained;
  - (f) of the process for making submissions to the **EDB** in respect of the intended **CPP proposal**; and
  - (g) of their opportunity to participate in the consultation process required of the **Commission** by s 53T of the **Act** after any **CPP proposal** is received and considered compliant by the **Commission**.
- (2) For the purpose of subclause (1)(e), where further information is available in hard copy only, the applicant must have ensured that any further information was readily available for inspection at the stated location.
- (3) For the purpose of subclause (1), the **CPP applicant** must-
- (a) provide all relevant information;
  - (b) provide information in a manner that promotes **consumer** engagement;
  - (c) make best endeavours to express information clearly, including by use of plain language and the avoidance of jargon; and
  - (d) provide **consumers** with (or notified them where to obtain) the information through a medium or media appropriate to the natures of the **consumer** base.

Compliance with clause 5.5.1(1)(d) is discussed in section 3.4.

Given the nature of consumer consultation, we have applied the following assessment techniques in analysing and considering the effectiveness of Aurora Energy's consumer engagement:

- high level governance and process reviews
- desktop review.

We consider that the other assessment techniques are inappropriate for our verification of Aurora Energy's consumer engagement obligations.

In establishing its consultation program, Aurora Energy consulted with New Zealand and Australian utilities and sector organisations on their experience in regulatory consultation. It also considered and incorporated learnings from previous CPP consultations into its consultation plan.

In delivering its consultation on its CPP, Aurora Energy established the following consultation forums:

- Customer Advisory Panel (CAP), which draws on the knowledge and experience of community organisations to represent the diverse interests of the community and residential, industrial, commercial and rural electricity consumers. Under the CAP terms of reference, the objectives of the CAP are:

*To advise and represent to Aurora Energy the perspectives and preferences, including the service measures, that are important to consumers.*

*To understand Aurora Energy's business in order to provide meaningful input into Aurora Energy's proposal for a customised CPP application, including its future investment plans and pricing options.*

*To advise Aurora Energy on consumer perspectives, and perceptions, of the possible impact of new technologies on electricity users.*

*To provide feedback on communication and engagement strategies to enhance Aurora Energy's communication with its community, consumer groups and electricity consumers.*

*To provide input into Aurora Energy's customer service process improvement ideas, to ensure Aurora Energy is able to capture systemic customer issues and improve the customer experience it provides.*

The CAP prepared and submitted an independent report on Aurora Energy's proposed CPP with the assistance of an expert advisor in December 2019.

- Customer Voice Panels (CVP) to hear directly from local electricity customers which bring together a cross-section of residential and small business customers with sessions held in each in Aurora Energy's key service regions of Dunedin, Central Otago and Queenstown Lakes.
- One on one meetings with key local stakeholders, retailers and industry organisations.
- Phone survey of 1,000 residential and 101 business customers.

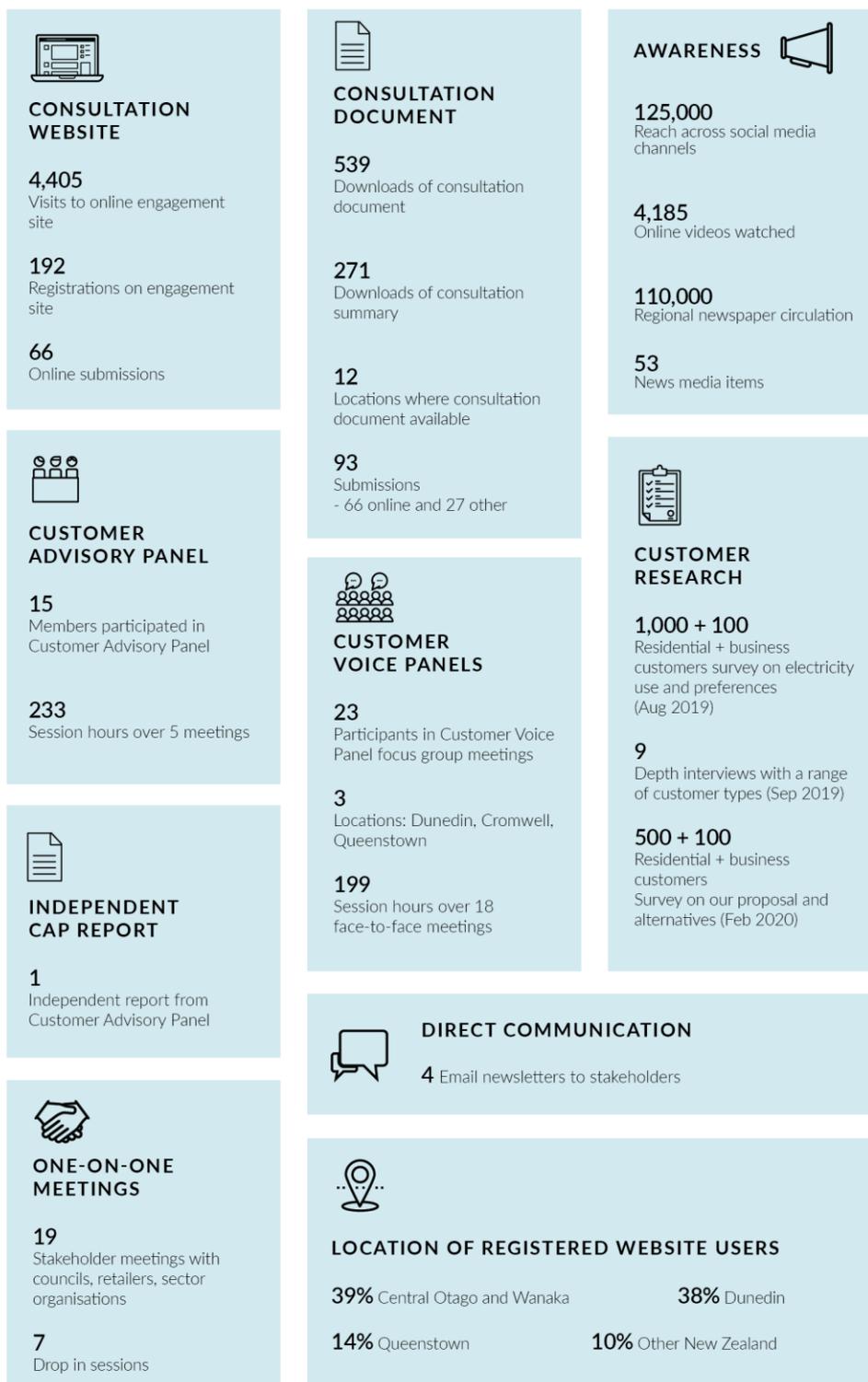
Aurora Energy created a CPP consultation web page on its website which provides access to engagement information and information relevant to its CPP proposal, encourages stakeholders to register their interest in being part of Aurora Energy's consultation and provides information on its engagement forums. For the CAP, Aurora Energy also established a private chat room for members to share ideas and ask questions.

Media avenues used by Aurora Energy included:

- Paid representative surveys
- YouTube / Facebook videos
- Google and Facebook sponsored posts
- LinkedIn
- Newspaper advertising
- Direct mail to key stakeholders
- Advertising inserts.

Figure 3.3 sets out the key consultation outcomes across the various forums that Aurora Energy intends to include in its final consultation report (which we have not reviewed).

Figure 3.3 – Aurora Energy’s key consultation metrics



Source: Aurora Energy.

We attended one of Aurora Energy’s CAP meetings in August 2019 to observe how it operated, met with Aurora Energy on 20 March 2020 to discuss its consultation program and have reviewed the consultation material prepared by Aurora Energy including glossy brochures, web-based videos, advertisements, and

material prepared following various consultation forums summarising findings. We reviewed material made available by Aurora Energy in hard and soft copy and digital format.

### 3.3.3 Our findings

We note that Aurora Energy’s consultation focussed on the forecast expenditure and price outcomes over the CPP period and did not cover the review period. Therefore, our findings are limited to consultation over the CPP period. Also, as noted earlier the impact of COVID-19 on its forecasts has not been considered by Aurora Energy nor has Aurora Energy tested with consumers on whether their feedback has changed since COVID-19.

Aurora Energy completed rigorous<sup>53</sup> consultation with its stakeholders which include the CAP, QLDC, Major Users Electricity Group (MEUG), Retailers, CODC, Dunedin City Council and the Commission. The material prepared and presentations made by Aurora Energy included:

- educating stakeholders on matters currently being faced by Aurora Energy on its network – including recognition that Aurora Energy has underspent on its network in the past
- educating and seeking stakeholder views on future technology expectations – e.g. solar and electric vehicles – and what role Aurora Energy’s network could play in facilitating customer preferences
- service level expectations
- price impacts for the three network areas and pricing transitioning options – noting that specific consumer feedback on transitioning and pricing impacts are for the Commission to consider
- advice on what matters the most to consumers.

The consultation appears open and honest and genuinely seeks stakeholder input to assist Aurora Energy in finalising its positions in its CPP.

It is not clear from Aurora Energy’s consultation material, including in *Your Network, Your Say*, how Aurora Energy’s proposed expenditure specifically addresses its safety requirements, nor whether the level of safety being addressed by Aurora Energy reflects GEIP. We note that in its independent report the CAP also had this concern and noted that<sup>54</sup>:

*This is a complex and technical matter that we are not qualified to challenge but must involve some judgement. It is essential that Aurora Energy’s assessment is subjected to robust challenge and peer review by the independent engineering verifier appointed by the Commerce Commission. They should ensure that a conservative definition of “safety” is not being used to justify a scope of work that is larger than what Aurora Energy’s customers would consider necessary to make the network safe by the end of the CPP period*

Aurora Energy used the independent engineering assessment completed by WSP in 2018 of the current state of Aurora Energy’s network to identify legacy safety risks and to help inform what its investment priorities should be. As mentioned earlier, Aurora Energy continues to address the agreed priority work

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<sup>53</sup> We note that Aurora Energy received the following unsolicited feedback from the CEO of the Queenstown Chamber of Commerce and Panel Member, Anna Mickell, in a newsletter to Chamber members: “I have been sitting on the consumer advisory group that Aurora has assembled to support their Commerce Commission application that will allow them to invest more and charge more. This has been the most extensive and in-depth engagement process that I have ever been a part of.” (Queenstown Chamber of Commerce, CEO Update 28.11.19, <https://www.queenstownchamber.org.nz/business-connect/news-advocacy/news/ceo-update-281119/>)

<sup>54</sup> Customer Advisory Panel response to Aurora Energy CPP consultation document, December 2019, paragraph 16.

from the WSP findings and will be addressed over the CPP and review periods. We have considered how Aurora Energy plans to address safety in its CPP proposal in section 1.5.7.

In its consultation, Aurora Energy did not present a counterfactual but rather presented its base case as a bare minimum with alternative options that could be added. Aurora Energy attempted to show increase in price outcomes of its proposed CPP compared with it staying on the DPP. However, outcomes were generally based on current information (for example, the percentage of assets at the end of their useful lives in 2019) rather than the expected information at the end of RY24.

MEUG was complimentary on Aurora Energy's 'constructive, pro-active and very clear communications and engagement' but suggested that Aurora Energy should use the DPP as a counterfactual and that it could provide better feedback if disaggregated estimates of changes in price, quality and trade-offs between price and quality were provided by Aurora Energy.<sup>55</sup> We agree that a clearer counterfactual could be provided and that one based on the DPP makes sense. However, we note that the timing of the Commission decision on DPP3 being 27 November 2019 made it problematic for Aurora Energy to accurately reflect DPP3 as a counterfactual in its consultation material, particularly given that significant consultation on the CPP occurred during September to December 2019.

We also agree with MEUG that better information could be provided by Aurora Energy on changes in price, quality and trade-offs between price and quality. We note that through Aurora Energy's engagement process, most stakeholders confirmed that they are sensitive to the total cost of electricity for their home or business.<sup>56</sup> In addition, phone surveys indicated high level of satisfaction with current reliability of power supply (86%)<sup>57</sup>. In *Your Network, Your Say* Aurora Energy did not provide details of what the service levels would be under the current DPP (noting the DPP3 timing issues above making this problematic) and what further benefits consumers would obtain under the CPP. Ideally, Aurora Energy should test consumers' willingness to pay for maintaining and potentially improving safety and reliability. In addition, it would have been useful to ask consumers in the response form in *Your Network, Your Say* how much extra they were willing to pay per month to maintain and/or meet safety requirements if they did not support Aurora Energy's proposed CPP plan.

Other key consumer feedback was that:

1. whilst the need for essential work was generally accepted and that network investment needs to be made for renewal and for the future, consumers were shocked at the level of the resulting price shocks and were concerned of the implications for vulnerable households
2. some consumers wanted reassurance that the network would be ready for a low-carbon future and/or greater use/incentives for renewable energy (e.g. solar)
3. the regional price differences were felt to be unfair by those paying most, though once explained, the principle was understood, even if the outcome remained unacceptable

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<sup>55</sup> MEUG letter dated 24 January 2020.

<sup>56</sup> For example, UMR's quantitative research completed for Aurora Energy in August 2019 stated that close to three-quarters (71%) of residential respondents agreed that they make significant efforts around the home to save as much electricity as possible and 63% agreed that the cost of electricity is worth it for the huge benefits it provides every day to their household. Over half (56%) of residential customers surveyed closely monitor how much electricity their household uses and just over half (53%) are concerned about how much electricity their household uses.

<sup>57</sup> Aurora Energy CPP Customer Engagement Verifier Workshop, 20 March 2020.

4. most consumer feedback<sup>58</sup> supported that Aurora Energy implement a smooth price transition of its proposed CPP to reduce price shocks (noting that Aurora Energy plans to agree the best approach with the Commission)
5. retailers want early indication of the price increases as Aurora Energy finalises its CPP to assist in their own price-setting cycle.

Lastly, we believe that Aurora Energy has listened to consumer feedback and has taken on board suggestions made in developing its final CPP proposal. For example, we understand that Aurora Energy:

1. has only put forward its proposed CPP plan with no accelerated or enhanced alternatives
2. in terms of other options considered by Aurora Energy but rejected and not included in its draft CPP plan<sup>59</sup>, included in its final CPP: worst serviced customers, some aspects of customer service (option B), such as improvements to new connections and better information during outages
3. lowered its proposed spend where it considered feasible to reduce the impact of price increases, and has reviewed the pricing methodology to smooth price increases (noting that the pricing methodology and price impacts are outside our scope of our review and are for the Commission to consider).<sup>60</sup>

We also understand that in response to consumer feedback, Aurora Energy plans to develop a communication plan for all stakeholders to maintain goodwill of consumers through CPP period.

### 3.3.4 Completeness and key issues for the Commission

By its nature consumer engagement will result in different outcomes depending on the consumer group being consulted and the form of engagement undertaken, including the method for providing information. Aurora Energy has targeted different consumer group representatives in its various forums to ensure that all groups have had an opportunity to provide their say, and has encouraged consumers to participate. We understand that some stakeholders raised concerns about notification,<sup>61</sup> but based Aurora Energy's description of the steps<sup>62</sup> it has taken we did not see its notification practices as problematic. To the extent that there remains concern then stakeholders have an opportunity to raise these during the Commission's forthcoming consultation process.

The Commission may wish to investigate the following matters:

1. if the Commission does not approve Aurora Energy's proposed CPP period but rather prefers that the review period apply, then Aurora Energy's consumer consultation is unlikely to meet the IM

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<sup>58</sup> 69% of the phone survey respondents prefer a smoothed option, and CAP recommended that Aurora Energy delay the largest price increases until all customers have received training on energy efficiency.

<sup>59</sup> On the basis that they do not directly relate to improving safety or reliability, that deliverability was questionable and that it did not think the extra cost was justified, Your Network, Your Say page 46.

<sup>60</sup> Although we have identified areas throughout this report where we consider it feasible for expenditure to be lower, Aurora Energy appears to have genuinely attempted to reduce its proposed expenditure where possible.

<sup>61</sup> For example, the Central Otago Mayor Tim Cadogan claimed the public session had been poorly advertised - <https://www.odt.co.nz/regions/central-otago/cadogan-criticises-aurora-over-drop-advertising>

<sup>62</sup> Aurora confirmed that it advertised the Central Otago event on Facebook event listing with event audience reach of 2,200; Facebook event boosted to a targeted Central Otago audience with a reach of 1,000; Aurora Energy's Facebook page on Monday 16 December with a reach of 1,300; Central Otago District Council Facebook page on Monday 16 December with 5,700 followers; banner advertisement on the Central App for six days (Central App has 26,000 downloads and is part of the daily routine for many Central Otago residents. In the week leading up to the drop in session, Central App was accessed 101,000 times); and listed on the Consulting Now page of the [yoursay.auroraenergy.co.nz](https://www.yoursay.auroraenergy.co.nz) consultation website. This was reflective of the steps applied to other public forums.

requirements. Therefore, if the Commission decides to apply the review period consideration needs to be given to what additional consultation is required to meet the IM requirements

2. a clearer counterfactual based on DPP3 to show the improvements in safety and reliability outcomes that are expected from the CPP, and explore with consumers what their thoughts on the identified improvements
3. consumers' willingness to pay for maintaining (and potentially improving) safety and reliability outcomes
4. the price impact of the CPP on Aurora Energy's customers at a more granular level to identify whether any customers are likely to receive unpalatable price increases
5. consideration of the impact of COVID-19 pandemic and expected economic impact on Aurora Energy's forecasts (including the potential to defer spend) and price outcomes, and on consumer price sensitivity
6. consideration of feedback from the CAP on its experience of Aurora Energy's consultation process. This was planned at the final CAP session on 30 April, *Closing the Loop and Celebrating*, which was cancelled while New Zealand was in COVID-19 lockdown.

As noted earlier, we expect that it is likely there will be instances where forecasts be affected by COVID-19. We also expect that consumers will be even more price sensitive now given the unrepresented measures that the New Zealand Government and governments around the world have taken to abate the spread of COVID-19. Therefore, by investigating the above matters we expect that the Commission may reconsider aspects of Aurora Energy's CPP.

## 3.4 QUALITY STANDARD VARIATIONS

### 3.4.1 Aurora Energy's proposal and our general observations

The Commission assesses each year the actual performance of EDBs against quality standards that it sets. In recent years, Aurora Energy has breached its quality standards – which culminated recently in it being ordered by the High Court to pay a fine of \$4,997,200 (\$nominal) for breaches over RY16 to RY19.<sup>63</sup>

Aurora Energy is currently – under the DPP for the 2020–25 period – subject to quality standard limits for both planned and unplanned SAIDI and SAIFI, with performance against planned limits assessed after the DPP period ends and performance against the unplanned limits assess each year. Major event days are excluded from the measures of SAIDI and SAIFI. If Aurora Energy's actual performance exceeds the specified levels, then there may be an investigation by the Commission with the potential for fines to be imposed by the New Zealand courts.

Aurora Energy is also subject to a quality incentive mechanism that rewards or penalises it for improved or deteriorating planned and unplanned SAIDI performance. The parameters used to apply the scheme are aligned with the quality standard limits and an assumed VoLL is used to convert performance into financial values.

Aurora Energy is proposing to vary its quality standard limit to:

- increase the unplanned SAIFI limit from 1.4687 to 2.5067 interruptions, and
- increase the unplanned SAIDI limit from 81.89 to 146.29 minutes.

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<sup>63</sup> *Commerce Commission vs Aurora Energy Limited* [2020] NZHC 610.

Aurora Energy explained that these changes are needed to better reflect its circumstances, including its deteriorating reliability performance in recent years.<sup>64</sup> The proposed unplanned SAIDI and SAIFI limits were calculated by adding two standard deviations to the maximum forecasts for both measures. The standard deviation values were those adopted for the DPP scaled up by the difference between Aurora Energy’s maximum forecasts and the targets adopted for the DPP.

We understand that Aurora Energy is not proposing to vary its quality incentive mechanism parameters, except to the update the unplanned SAIDI target to reflect the proposed updates to the unplanned SAIDI forecast.<sup>65</sup>

### 3.4.2 IM requirements and our approach to assessment

This section aims to address Schedule G3(2) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 6 – IM requirements for any quality standard variations

##### Schedule G3(2) of the IM:

Where the **CPP applicant** intends to propose a **quality standard variation** in the **CPP proposal** under clause 5.4.5, the **verifier** must review, assess and report on the extent to which the **quality standard variation** better reflects the realistically achievable performance of the **EDB** over the **CPP regulatory period**.

Our approach to assessment was:

- identify what, if any, quality standard variations Aurora Energy proposes, including any proposed changes to service measures or levels
- consider the extent to which any proposed variations better reflect the realistically achievable performance of Aurora Energy over the CPP and review periods.

Table 3.4 presents the information that has been provided by Aurora Energy in relation to the quality standard variation. We also relied on some information listed in Table 3.2 above to assess the realism of the proposed targets.

Table 3.4 – Information provided – quality standard variation

Title	Reference	Date
QS03 - Quality standards incentives	E-71	6 March 2020
<b>Provided in response to our draft report</b>		
200426 VOLL note	PR-30	26 April 2020
Aurora VoLL report FINAL	PR-31	26 April 2020
PWC_Estimating the Value of Lost Load	PR-32	26 April 2020

<sup>64</sup> Aurora Energy, CPP Quality Standards Memo, 5 March 2020, pp. 1–2.

<sup>65</sup> At the time of our draft report, Aurora Energy was also considering whether to propose lowering the VoLL used in the quality incentive. Aurora Energy subsequently confirmed that it was no longer intending to propose that change.

Title	Reference	Date
Transpower Value of Lost Load (VoLL) Study	PR-29	26 April 2020
Memo Responding to Reliability Penultimate Draft Feedback.docx	PD-3	1 June 2020
Memo Regarding CPP Application Quality Standard	PD-12	4 June 2020

### 3.4.3 Our findings

We have interpreted the IM requirements as requiring us to only review changes to quality related forecasts, rather than any changes to the design of the quality standard or incentive mechanism. This was confirmed by the Commission, where it advised that we do not need to review Aurora Energy’s proposal to use two standard deviations to determine the unplanned SAIDI and SAIFI limits.<sup>66</sup>

In our view, Aurora Energy’s proposed unplanned SAIDI and SAIFI targets and resulting limits, normalised to remove major event days, are realistically achievable because:

- as noted above, we consider that it is likely that Aurora Energy’s unplanned SAIDI and / or SAIFI performance will improve over the CPP and review periods due to the current and proposed maintenance, vegetation management and asset renewal programs
- our alternative forecasts for both measures are based on adjustments to Aurora Energy’s model to use renewal model survival data and calibrating the model to historical normalised SAIDI, SAIFI and CAIDI performance – the forecasts are lower than those proposed by Aurora Energy, factoring in these expected movements and allowing for other general aging of the network.

For the reasons expressed in section 3.2.3 above and detailed in Appendix E, we have concerns about the methods used by Aurora Energy to calculate the unplanned SAIDI and SAIFI forecasts and targets.

We have not explicitly reviewed Aurora Energy’s proposal to use two standard deviations above the targets to determine the unplanned SAIDI and SAIFI limits; however, we note that it may be inappropriate to use the same standard deviation values (as opposed to the number of them) adopted for the DPP to determine those limits because:

- some of the variability in historical unplanned SAIDI and SAIFI – which underpins the standard deviation values estimated by the Commission for the DPP – is accounted for in the forecasts prepared by Aurora Energy (i.e. asset health is used to forecast those measures)
- improving asset health, maintenance and vegetation management practices – resulting from the proposed expenditure over the CPP and review periods – would be expected to improve network resilience to weather and other events outside of Aurora Energy’s control and its responsiveness to any outages caused by the same
- the limits could be based on two standard deviations, but recalculated using lower revised targets such as those determined by our modelling
- as noted above, consumers have indicated that Aurora Energy should focus on addressing safety concerns – setting a limit too low may drive Aurora Energy to invest to improve reliability at the expense of safety outcomes, while setting it too high may lead to insufficient investment to avoid deteriorating reliability performance.

<sup>66</sup> Email from Karen Smith to Alec Findlater, RE: Verifier Query – IM Interpretation, 19 March 2020.

Aurora Energy is forecasting a lower planned SAIDI target compared to our alternative modelling and therefore its proposed target under the incentive mechanism will be more difficult to achieve if our forecasts are correct.

When consulting with consumers on its CPP proposal, Aurora Energy did not explicitly consult on its proposal to update the quality standard limits. However, Aurora Energy provided consumers with information on expected quality outcomes to enable them to form a view on Aurora Energy's plan to maintain current unplanned reliability over the proposed CPP period and into the future was acceptable if it meant a short-term increase in planned outages.<sup>67</sup> This is not unreasonable in the circumstances, including as to the timing of when its reliability forecasts were prepared.

#### **3.4.4 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed service measures was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

If the expenditure forecasts change, then this may affect whether the proposed unplanned SAIDI and SAIFI limits need to be adjusted to account for these changes so that they are realistically achievable.

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<sup>67</sup> See, for instance: Aurora Energy, *Your Network, Your Say*, November 2019, pp. 24–25. Note that the reliability forecasts consulted on with consumers differ slightly from those provided to us to review. Aurora Energy also included forecast SAIDI planned and unplanned outcomes in the various consultation forums it conducted (i.e. the CAP and CVP meetings).

## 4. Capital expenditure

In this chapter, we assess Aurora Energy’s forecast capex against the expenditure objective and the schedule G IM requirements. This required us to:

- form a view on Aurora Energy’s policies and planning approaches, assumptions, and forecast models
- summarise our conclusions from a detailed review of identified capex programs and projects.

This chapter is structured as follows:

Heading	Sets out
Section 4.1	Findings on Aurora Energy’s forecast capex against the expenditure objective
Section 4.2	Findings on Aurora Energy’s policies and planning standards as they relate to its forecast capex
Section 4.3	Findings on key assumptions underpinning Aurora Energy’s forecast capex
Section 4.4	Conclusions from our review of identified capex programs and projects
Section 4.5	Findings on the deliverability of Aurora Energy’s forecast capex
Section 4.6	Findings on the asset replacement models used by Aurora Energy to develop its forecast capex
Section 4.7	Observations about measuring the performance of renewal expenditure

### 4.1 EXPENDITURE OBJECTIVE

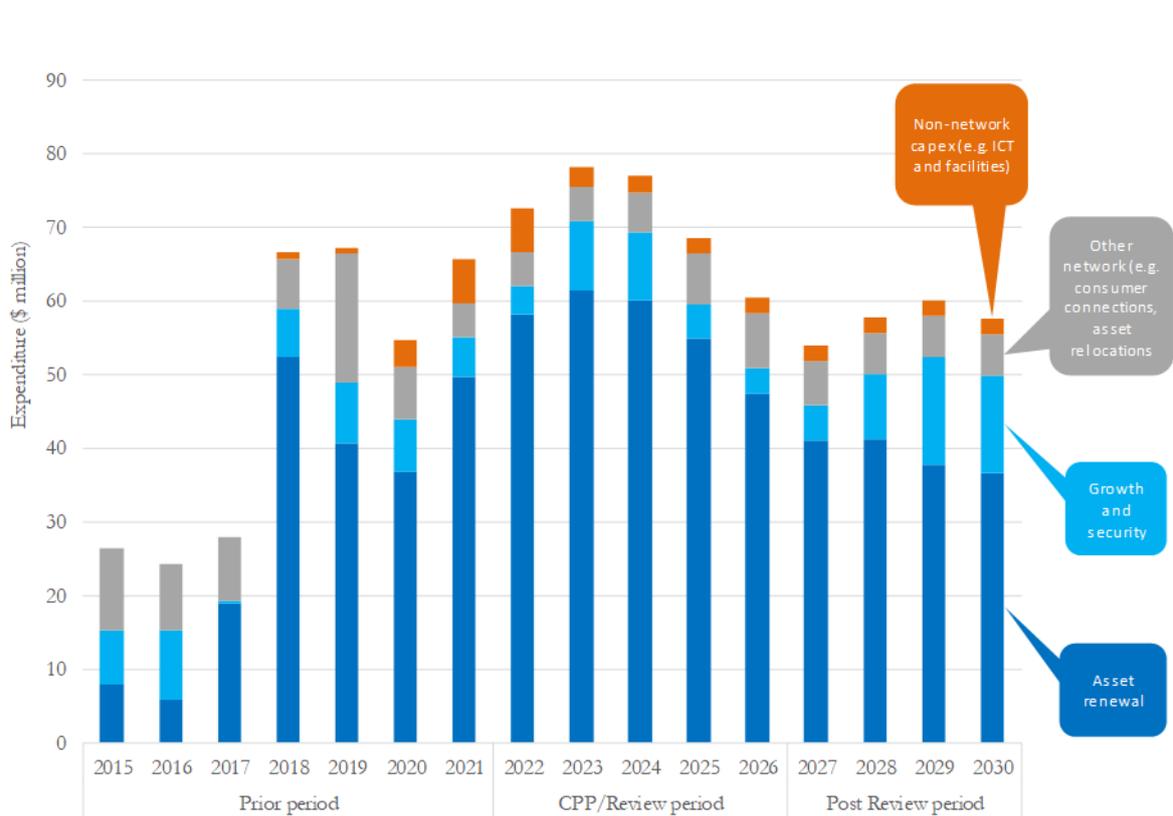
#### 4.1.1 Aurora Energy’s proposal and our general observations

Aurora Energy proposes capex over the CPP period of \$227.7 million and \$356.6 million over the review period.

This can be compared over three distinct periods in the past and as forecast, also illustrated in Figure 4.1:

- RY15 to RY17 \$78.6 million (three-year period – \$26.2 million per annum)
- RY18 to RY21 \$254.2 million (four-year period – \$63.6 million per annum actual and forecast)
- RY22 to RY24 \$227.7 million (CPP period – \$75.9 million per annum forecast).

Figure 4.1 – Capex forecast (\$2020, \$million)



Source: Data from Aurora Energy, graph prepared by Farrierswier and GHD.

The increase in expenditure over the CPP and review periods compared to the RY18-RY21 period is attributed by Aurora Energy principally due to:

- increased levels of replacement of the overhead network, particularly new programs including overhead conductors and crossarms
- increased levels of replacement of zone substation equipment such as the replacement of indoor and outdoor switchgear and building upgrades, and increased replacement of power transformers and protection systems
- general increases in expenditure of other network assets.

This further contrasts with the earlier period RY15 to RY17 which preceded the major step up in capital expenditure for the fast track pole program (FTPP) and subsequent years of elevated levels of pole replacements and other network renewals. The pole program expenditure is trending down over the CPP and review periods.

#### 4.1.2 IM requirements and our approach to assessment

This section aims to address Schedule G5(2) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

## Box 7 – IM requirements for capex forecasts

### Schedule G5(2):

Based on its analysis under this clause the **verifier** must provide its opinion on whether the **CPP applicant's** forecast of total capex meets the **expenditure objective** and, if not identify-

- (a) whether the provision of further information is required to enable assessment against the **expenditure objective** to be undertaken and, if so, the type of information required;
- (b) which of the **CPP applicant's forecast capex programmes** for each **capex category** might warrant further assessment by the **Commission**; and
- (c) what type of assessment would be the most effective.

We assessed Aurora Energy's proposed capex against the requirements set out in Schedule G of the IM, which we detail further below. This involves assessing:

- Aurora Energy's policies and planning standards and how these applied in developing the forecast expenditure
- the key assumptions and drivers that underpin the forecast expenditure and the models used to derive those forecasts
- selected capital projects and programs
- the deliverability of the forecast expenditure.

### 4.1.3 Our findings

The CPP and review period forecasts represent a significant uplift in expenditure in most capex categories, except for pole replacements which are trending down to long run expected volumes following the FTTP.

Aurora Energy is on a path of improvement with its asset management practices and needs to manage deteriorating condition of its networks that is impacting on safety and reliability, and future network growth, and that this need may warrant an increase in expenditure for particular aging network assets.

There are many components of Aurora Energy's capex forecasts for the CPP and review periods that support the expenditure objective such as:

- Aurora Energy's executive and management teams have applied their expertise to develop sound plans, business cases for growth projects and renewal models in most instances that support the expenditure objective. These plans appear to comply with the range of policies and planning standards currently in place, and although in Aurora Energy's situation they are not as well developed as other EDBs and comparable organisations, this has not had a material impact for most programs – although there are some exceptions.
- Generally, the forecasting methodologies applied, the models developed, and the quality and robustness of those models do not appear inappropriate and are consistent with current industry practise.
- The method that Aurora Energy has used to capture competitive based costs from its service providers appears to be good practice.
- The method that Aurora Energy has used to coordinate and levelise work to avoid peaks and troughs in resources requirements over the periods also appear to be reasonable and with the stated aim to use

criticality over the period to prioritise work packages should help manage safety risks over the CPP and review periods.

- The goods and services procurement strategy adopted and currently being implemented is appropriate with a balance of competitive tension and the consideration of business need, risk, value, project timing and the application of minimum allocated work volumes for service providers to secure resources at efficient costs.
- Most assumptions applied in the development of the forecast do not appear to be unreasonable.
- Aurora Energy has incorporated the potential impact of the COVID-19 pandemic on timing and need for growth related projects and connection expenditure.
- Aurora Energy has also applied top-down efficiency adjustments that reflect the potential benefits from improvements to asset management and other systems, procurement strategy, and other initiatives.

However, several components of Aurora Energy's capex forecasts do not support the expenditure objective. These are:

- The asset strategy for the CPP period does not include allowance for a continuation of the wood pole reinforcement program which could defer capital expenditure due to technical and safety concerns with the practice. Our findings on this matter have resulted in the unverified amount for the subsequent years over the review period which we expect should result in a continuation of the program with further engineering reviews which should be undertaken during the CPP period.
- Although acknowledged by Aurora Energy, lack of specific asset class performance measures and targets can affect expenditure forecasts – establishing interim targets would have provided a degree of understanding of prudent levels of residual risk (safety as the key focus) and would have assisted in decision making for each renewal program. We understand that Aurora Energy intends to develop these over the CPP period.
- The proposed Arrowtown 33 kV ring upgrade project appears reasonable; however, the economic justification depends on projected demand being realised. Given the significant impact that the COVID-19 pandemic is likely to have in the area affected by the project, we consider the upgrade could be treated as a contingent project.
- Similarly, although the proposed major tourism operator's connection upgrade project appears reasonable, whether it is needed depends on the operator formally requesting an update. With significant restrictions on international travellers and other consequences from the pandemic, demand for tourism may be depressed for some time. For this reason, it is not clear to us when – if at all – the major tourism operator will make such a request. As such, we consider that this upgrade could also be treated as a contingent project.

These issues are likely to result in expenditure that is too high for the identified capex programs, to an upper limit of \$3.3 million over the review period (and \$0 over the CPP period). In addition, there are identified growth and connection upgrade projects that we consider could be treated as contingent, totalling \$5.4 million and \$7.5 million over the CPP and review periods, respectively.

The reasons for our view and findings are discussed in the following sub-sections, and are informed by our detailed review of capex projects and programs contained in Appendix C and Appendix D. We also separately consider Aurora Energy's proposed cost escalation of its capex and opex forecasts in section 6.4.

Importantly, we have only reviewed 66% of Aurora Energy's forecast capex for the CPP and review periods, comprising the 11 identified capex projects and programs (see Appendix B). We were unable to review whether the remaining 34% of Aurora Energy's forecast capex satisfied the expenditure objective.

As noted in in Appendix C and Appendix D, lack of sufficient asset condition data and risk management tools at this stage of Aurora Energy's asset management development may lead to under- or over- stated expenditure requirements for overhead conductors and crossarms. However, the forecasts and methods used by Aurora Energy are generally consistent with industry practice as data is practically limited for these types of overhead assets.

#### 4.1.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As noted above, we have identified several concerns with key aspects of Aurora Energy's capex forecasts. When undertaking its own assessment of the information, we recommend that the Commission focus on:

- **Business cases for growth projects** – undertake sensitivity analysis of key inputs including the demand forecast, the VoLL used, the project costs and the discount rate applied. Options to partly develop the projects over the CPP and review periods to mitigate for unknown demand increases could be considered.
- **Risk assessments** – consider which of Aurora Energy's renewal programs should be supported by risk assessments to confirm findings or address concerns in this report. LV enclosures, high voltage (HV) and LV overhead conductors and crossarms are examples within the identified programs reviewed.
- **Transformer renewals** – request Aurora Energy to review its transformer renewal model to address our concern as to how condition data is mapped to asset health which appears to be leading to an overstated volume of replacements required over the CPP and review periods. This did not affect the expenditure forecast as the required numbers were later deferred though the project coordination process.
- **Performance measures** – the Commission may wish to discuss the establishment of interim measures and targets for the CPP and review periods which would assist in understanding the residual risk and provide line of sight to the quality standards, potentially both reliability and safety measures.
- **Cost escalators** – the Commission may wish to procure its own cost escalator forecasts from a sufficiently qualified and independent third party to compare to those proposed by Aurora Energy.
- **Improvement in management systems** – the Commission may wish to get updates from Aurora Energy over the CPP period on its progress to improve key management systems and processes, including the asset management systems. We think that it is important that aiming to seek ISO55001 certification by 2023 does not distract Aurora Energy from achieving higher priority improvements in the asset management system and the overall wider management systems improvements.
- **Non-identified programs** – consider reviewing the remaining 34% of Aurora Energy's capex forecasts that we did not review. As a minimum, this should involve:
  - examining the underlying assumptions and criteria that form the basis for expenditure forecast such as the formation of the age profile of the asset fleet, asset condition or performance scores, and the application of selected asset strategy
  - benchmarking expected asset lives and replacement volumes with other EDBs as a method to assess the appropriateness of managing safety, reliability and other risks with the expenditures forecast and to identify areas requiring further review

- reviewing the estimating processes as to how unit rates have been determined – whether based on historical rates, recent competitively sourced rates or other methods – as a method to assess the efficiency of the delivery costs
- assessing the deliverability of the program of work and the procurement approach considering availability of the required technically skilled workforce and the uplift in resource requirements
- reviewing whether sound business case principles and sensitivity analysis have been used for growth and other non-identified programs
- assessing whether any of the non-identified programs, or components of them, should be considered contingent projects, especially given the presently unclear impact that the COVID-19 pandemic impact may have on economic justifications.

## 4.2 POLICIES AND PLANNING STANDARDS

### 4.2.1 Aurora Energy's proposal and our general observations

Aurora Energy is currently developing a set of policy and planning documents covering the core aspects of its operations that we would expect in more mature organisations. Aurora Energy provided us with a list of these policies and planning standards and any specific policies and planning standards that we sought to see.

With respect to capex programs, we have reviewed key documents such as the AMP 2018-2028 and the associated portfolio overview documents (PODs) in lieu of specially developed asset class plans or business cases in the case of growth projects.

Our general observation is that Aurora Energy is still in a very early stage of transferring legacy documents from the predecessor organisation and building a document management system that would be considered to be in a mature state. The focus has been on transferring operational procedures first and then secondly overarching guidelines to provide overall direction. As a simple measure, the number of guidelines is relatively low at this stage compared to more mature management systems in place by other organisations.

Aurora Energy has focussed on key guidelines documents in the short term in the areas such as protection systems, network design reliability, project management, security of supply and document management.

The controlled document system (CDS) is being built with a structure for standards, procedures, guides and forms. These documents do not have authorisation blocks or dates which are requirements of quality control systems. Some documents listed in the system are in draft form. These comments are not meant to indicate poor organisational performance in this regard but to observe the current state of Aurora Energy's policy and planning document development – which is relevant context to its forecasting methods.

We also observed in workshops and discussions with senior management that there appear to be sound practices and systems in place that are being followed by the organisation at a corporate level. Many of these practices and systems are yet to be documented. It is a testament to the new management team that they are providing the guidance necessary in support of the capital investment proposals for the CPP.

We would expect the organisation to be developing overarching frameworks (more directive than guides) including for the following areas:

- investment governance
- integrated management system

- risk management (linking all subsets of risk management in the organisation)<sup>68</sup>
- asset management (an “asset management system” as defined in ISO55001)
  - asset health and criticality
  - asset performance
  - system assurance
  - asset data, information management and change management
  - continuous improvement
- project management (linking all subsets of project management in the organisation)
- quality and safety management.

Some of the above documentation may exist but we were not provided with them or any strategy document to show the intended development of them. There also appear to be significant gaps in some documents that would be expected to sit under these frameworks.

Aurora Energy’s website contains links to specific policies and charters that are for governance and guidance of the organisation and provides copies of relevant documents including the executive leadership governance structure. Commensurate with leading business practice in asset rich organisations, an asset management policy is required to be developed (and a requirement of ISO 55001) and asset management accountabilities to be specifically included in board and executive charters – the audit, risk and compliance committee and internal audit charter in the case of Aurora Energy.

Aurora Energy has set an ambitious undertaking to achieve leading practice asset management capability within five years and plans to achieve certification to ISO 55001 over the CPP period. In our experience, given the current starting point, this will require significant resources and attention over the CPP period, and more than may be anticipated by Aurora Energy. If not managed carefully, this may have a negative impact on the attention needed over the CPP period to efficiently deliver the capex programs of work and to re-adjust strategies and aspects of the programs that will inevitably occur over the period.

We are confident that the management team can progress the development of policies, systems and documentation in alignment with ISO 55001 and will manage processes generally to this standard.

#### 4.2.2 IM requirements and our approach to assessment

This section aims to address Schedule G5(1)(a) and (b) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

##### Box 8 – IM requirements for capex policies and planning standards

###### Schedule G5 (1) of the IM:

The **verifier** must:

- (a) Provide an opinion as to whether the-
  - (i) **policies;**
  - (ii) **planning standards;** and
  - (iii) ...,

<sup>68</sup> A risk management model is in place.

relied upon by the **CPP applicant** in determining the **capex forecast** are of the nature and quality required for that **capex forecast** to meet the **expenditure objective**;

- (b) provide an opinion as to whether the **capex forecast** has been prepared in accordance with the **policies** and **planning standards** at both the aggregate system level and for each of the **capex categories**;

Our approach to assessment is to obtain a list of relevant documents and to select a sample for review including those likely to be significant drivers of forecast expenditures. Documents are examined for:

- version control to show the status of the document and the appropriateness of approval levels
- clarity of content to show reliability in application and that clear and appropriate guidance is delivered
- key guidance is consistent with industry practice.

The application of the key policies and procedures is also tested at the project or program level, particularly to assess whether the application of the policy/procedure is correctly implemented and that this supports the achievement of the expenditure objectives. The results of these reviews are contained in Appendix C in relation to verifying the expenditure objective and Appendix D in relation to verifying the renewal models.

### 4.2.3 Our findings

We consider that Aurora Energy's current policies and planning standards for most of its capex programs have led to efficient forecasts.

The capital expenditure forecasts represent a significant uplift in expenditure in most capex categories, except for growth related projects. Aurora Energy is clearly on a path of improvement with its asset management practices and recognise the need to manage deteriorating condition of its networks impacting on safety and reliability, and future network growth, and that this need may warrant an increase in expenditure from current levels.

With respect to whether the 'policies and planning standards relied upon by Aurora Energy in determining the capex forecast are of the nature and quality required for that capex forecast to meet the expenditure objective' we have found:

- Aurora Energy's policies and standards are currently at a low level of maturity and hence by their nature and quality they may not have been able to be relied upon in the full extent to meet the expenditure objective, but
- Aurora Energy has management processes in place that may not yet be documented and with the management roles, responsibilities and skills they have been able to develop, the capital forecasts are based on sound approaches and decision-making tools in most instances.

With respect to whether the capex forecast has been prepared in accordance with the policies and planning standards at both the aggregate system level and for each of the capex categories we found that Aurora Energy has prepared the capex forecasts in accordance with the policies and standards that are in place.

Some of the documents and the practices that followed from them do not appear to be of the required nature and quality to have provided sufficient guidance in their application. These are discussed below.

### ***Growth – Riverbank and Arrowtown 33 kV ring upgrades***

Aurora Energy has developed an internal security of supply guidelines based on a review of other industry-standard guidelines from other EDBs. These guidelines are not considered binding but are used as a guide for decision making and option analysis for projects undertaken to meet an identified network need. This guideline has been followed in the preparation of proposals for these two growth projects.

While an N-1 supply standard as defined in this guideline appears to be common practice in New Zealand, it is inconsistent with many overseas jurisdictions that adopt a probabilistic standard that seeks to minimise supply loss risk against the investment cost. The N-1 deterministic standard often leads to earlier augmentation and hence higher remediation costs than if the standard allowed some energy to be placed at risk of loss.

Aurora Energy's business case has assumed several inputs that could vary by material amounts leading to the projects being economically not viable. In the absence of an investment guidance or governance process document there does not appear to be sensitivity analysis conducted around these variables (see section 4.4.3 below for more detail).

### ***Renewals - general***

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry good practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards that apply throughout the asset life cycle management steps.

We reviewed several operational standards and forms related to the specific renewal programs. Aurora Energy should maintain the currency and relevancy of these operational document as it progresses through its asset management maturity journey and this depends on a quality-controlled document management system.

We are satisfied that the asset management plan provides effective direction to manage this fleet of Aurora Energy's network assets. However, the efficient application of the plan is presently limited by asset data availability and quality that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further optimise asset strategies and expenditure forecasts.

A data standards document should be developed to provide guidance in the management of data and the data requirements for an asset register as part of the implementation of the proposed EAM system. This will be an improvement that will assist in optimising strategies during the CPP and review periods.

### ***Renewals – zone substation transformers***

The authorisation process for the zone substation renewal models followed a review and authorisation process that may or may not be formally documented. The risk of not having an appropriate process of review is that the decision-making tools may lead to invalid outcomes resulting in material expenditure or unmitigated risk outcomes.

### *Unit rate and estimating building blocks*

In our experience Aurora Energy would benefit from a more comprehensive estimating management system and policy and procedures that guide development and testing of the accuracy of unit rates and building blocks used in project estimates.

There were minimal instances where we have considered changes to rates and project estimates for capex forecasts, however the process of review was made difficult without a rigorous system in place. The risk is that estimates used in the forecast may not be as efficient as it may otherwise be.

### *Application to forecast expenditure*

In our view, based on our assessment in relation to this CPP proposal, Aurora Energy has generally prepared the capex forecast in accordance with the policies and planning standards available at the time and, in some cases, those that it is still developing.

## **4.3 KEY ASSUMPTIONS**

### **4.3.1 Aurora Energy’s proposal and our general observations**

In our opinion, most of the assumptions used by Aurora Energy to develop its capex forecast are appropriate and are likely to result in an expenditure forecast that meets the expenditure objective.

However, some of Aurora Energy’s key assumptions relevant to the capex forecast do not appear to be reasonable and are likely to result in an overstatement of expenditure.

These are summarised in section 4.3.3 and explained in detail within the project and program reviews set out in Appendix C and Appendix D.

### **4.3.2 IM requirements and our approach to assessment**

This section aims to address Schedule G5(1)(a) and (c) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### **Box 9 – IM requirements for capex key assumptions**

##### **Schedule G5(1) of the IM:**

The verifier must:

- (a) provide an opinion as to whether the-
  - ...
  - (iii) **key assumptions**,  
relied upon by the **CPP applicant** in determining the **capex forecast** are of the nature and quality required for that **capex forecast** to meet the **expenditure objective**;
  - ...
- (c) provide an opinion on the reasonableness of the **key assumptions** relevant to capex relied upon the **CPP applicant** including-
  - (i) the method and information used to develop them;

- (ii) how they were applied; and
- (iii) their effect or impact on the **capex forecast** by comparison to their effect or impact on **actual capex**;

Our approach to assessment was to:

- identify the assumptions relied upon by Aurora Energy to develop its capex forecast
- review these assumptions against what we would expect to see for a prudent non-exempt EDB, in terms of both nature and quality
- review the method and information used to develop those assumptions, including any supporting models, business cases or strategy documents
- review how these assumptions were applied, including in the relevant capex forecast models
- consider the effect or impact of the assumptions on the proposed capex forecasts, including by considering their effect or impact on actual capex (where relevant).

### 4.3.3 Our findings

In our view, most of the assumptions made by Aurora Energy in the development of its capex forecast are appropriate and are likely to result in an expenditure forecast that meets the expenditure objective.

However, several of the key assumptions relevant to the capex forecast do not appear to be reasonable and may result in an under- or over- statement of forecast expenditure.<sup>69</sup>

These are explained below:

- **Acceptable residual risk** – the assumptions of acceptable residual risk, from an ALARP perspective, for the safety driver or network performance perspective for the reliability driver, are assumed in all of the modelling methods that use age-based replacement models. Yet, forecasts are very sensitive to the age assumptions. Although the volume forecasts for the identified renewal programs that we have reviewed do not appear unreasonable based on the information available, and our benchmarking, better access to asset condition data should lead to more accurate forecasts that may be higher or lower. Given the significant step up in preventative maintenance proposed from the start of the CPP period, Aurora Energy should be able to improve its volume forecast significantly by the end of the CPP period. Starting the renewal programs early in the CPP and review periods would also inform as to the actual condition of the asset fleets (e.g. as replaced assets can be assessed).
- **Criticality** – Aurora Energy has stated that it plans to implement a criticality framework that can be used with asset health to apply a risk-based approach to prioritising forecast asset replacements based on safety and reliability consequences. This change has potential to affect the medium-term replacement volumes required, with the potential outcome being reduced volumes.
- **Efficiencies** – Aurora Energy has not included factors in its models to account for potential efficiencies gained during the CPP and review periods from a variety of changes to current practices, and has not clearly separated out the benefits due to this framework and other efficiencies that it could expect.
- **Sensitivity to inputs** – Aurora Energy has assumed input parameters in the growth project business cases but has not conducted formal, structured sensitivity analysis on those inputs differing from the assumed values. These include VoLL, discount rate, capital costs, demand forecasts and probability of

<sup>69</sup> To be clear, based on the information available we did not confirm either way whether these assumptions did in fact lead to forecasts that are too high or too low.

asset failure. The business cases are sensitive to these inputs and small changes could result in deferring the project need beyond the CPP period and potentially the review period.

- **Linkage between capex and opex** – although Aurora Energy has recognised that there is some link between capex renewals and maintenance strategies,<sup>70</sup> the linkage is not modelled directly. This could lead to either under- or over- stated opex maintenance costs.

Our view on the key assumptions is also subject to the following limitation:

- **Cost Escalation** – the capex by program is adjusted for real input cost escalation based on escalators independently forecast by Sapere.<sup>71</sup> We consider that they are no longer appropriate given the significant impact that the COVID-19 pandemic is having and likely to have on costs. The Commission may wish to procure its own cost escalator forecasts from a sufficiently qualified and independent third party to compare to those proposed by Aurora Energy (see section 6.4 for further discussion).

## 4.4 REVIEW OF IDENTIFIED PROGRAMS

### 4.4.1 Aurora Energy’s proposal and our general observations

The following sections set out a summary of our findings for each of the identified projects and programs. Full details of our review are provided in Appendix C.

### 4.4.2 IM requirements and our approach to assessment

This section aims to address the relevant requirements set out in Schedule G5 of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 10 – IM requirements for G5 (1) and (2)

##### Schedule G5(1) and (2) of the IM:

(1) The verifier must-

...

- (d) report conclusions of a detailed review of **identified programmes** that are **capex projects** or **capex programmes** including, but not limited to assessment of-
- (i) whether relevant **policies** and **planning standards** were applied appropriately;
  - (ii) whether **policies** regarding the need for, and prioritisation of, the **project** or **programme** are reasonable and have been applied appropriately;
  - (iii) the process undertaken by the **CPP applicant** to determine the reasonableness and cost-effectiveness of the chosen solution, including the use of cost-benefit analyses to target efficient solutions;

<sup>70</sup> For instance, Aurora Energy has included top-down reductions to corrective and reactive maintenance expenditure forecasts due to improving asset condition. Similarly, Aurora Energy intends to draw from condition data collected through its proposed preventative maintenance program to inform what assets are renewed and when.

<sup>71</sup> The capex models forecast expenditure in real \$2020, before forecast inflation and real input cost escalation is applied. This escalation is applied separately in the CPP BBAR (i.e. financial model).

- (iv) the approach used to prioritise **capex projects** over time including the application of that approach for the **next period**;
  - (v) the **project** capital costing methodology and formulation, including unit rate sources, the method used to test the efficiency of unit rates and the level of contingencies included for **projects**;
  - (vi) the impact on other cost categories including the relationship with **opex**;
  - (vii) links with other **projects**;
  - (viii) cost control and delivery performance for **actual capex**;
  - (ix) the efficiency of the proposed approach to procurement; and
  - (x) whether it should be included as a **contingent project** or part of a **contingent project**;
- ...
- (2) Based on its analysis under this clause the **verifier** must provide its opinion on whether the **CPP applicant's** forecast of total **capex** meets the **expenditure objective** and, if not identify-
- (a) whether the provision of further information is required to enable assessment against the **expenditure objective** to be undertaken and, if so, the type of information required;
  - (b) which of the **CPP applicant's forecast capex programmes** for each capex category might warrant further assessment by the **Commission**; and
  - (c) what type of assessment would be the most effective.

Our approach to reviewing the projects and programs was to:

- identify and review the documentation including models used to justify each of the key projects or programs and alignment with business policies and standards
- assess the information provided against common industry practice, appropriateness of forecasting methodologies, models and inputs
- undertake staff interviews to clarify any concerns and submit any questions through the SharePoint site query process that was established
- where available, consider benchmarking with other EDBs
- consider any relationships between project and programs within the capex forecast and relationships with the opex forecasts and how these have been incorporated into the method or methods, or not
- review any methods used by Aurora Energy to check the reasonableness of its capex.

We reviewed the following identified capital projects and programs:

- Asset renewals
  - poles
  - crossarms
  - distribution conductors
  - LV conductors
  - zone substations
    - buildings

- power transformers
- indoor switchgear
- outdoor switchgear
- LV enclosures
- protections
- Growth
  - Arrowtown 33 kV ring upgrade
  - Riverbank zone substation upgrade
- Other capex – connections expenditure
- Non-network capex – ICT.

### 4.4.3 Our conclusion

Our conclusions from this review are set out below. These conclusions inform our overall findings on capex, and our findings on other clauses within schedule G5 of the IM.

#### *Renewals – poles*

The poles renewals program covers replacements of poles that have deteriorated in condition or otherwise require replacement resulting in total expenditure of \$35.2 million over the CPP period and \$47.9 million over the review period. The primary objective identified by Aurora Energy is to maintain the safety of the network.

Based on our assessment of the CPP proposal and supporting material, the overall approach for pole replacements is appropriate given the asset management maturity context over the CPP period. We consider that the pole replacement expenditure forecast over the CPP period is consistent with the expenditure objective.

By the end of the CPP period, we expect that Aurora Energy will have established a new and improved asset management system and its asset strategy to consider wood pole replacement vs. reinforcement activity. Such improvements should allow Aurora Energy to undertake some pole reinforcement activity (e.g. pole nailing). We estimate that this could reduce the required expenditure over the last two years of the revenue period by \$3.3 million – and so consider that this component is unverified against the expenditure objective.<sup>72</sup>

#### *Renewals – crossarms*

The crossarm renewals program covers replacement of crossarms that have deteriorated in condition or otherwise require replacement. Aurora Energy initiated this renewal program from RY20; there was no dedicated crossarm renewal program prior to that (crossarms were previously included within pole renewal, re-conducting or reactive work).

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<sup>72</sup> Aurora Energy has forecast some top-down efficiency improvements from RY27 onwards. However, it is not clear whether these improvements relate to reinforcement opportunities. Our estimate of a \$3.3 million reduction in the pole renewal forecast for the RY25–RY26 period is based on our assessment of Aurora Energy’s recent wood pole reinforcement activity during the FTTP, comparative practice by Australian and New Zealand EDBs, appreciation of local geotech conditions, legacy wood pole foundation design, various associated (poletop structure) defect issues, industry knowledge, and the limited opportunity or proportion of wood pole fleet that is suitable for reinforcement. This is explained in detail in section D.3.8.

Aurora Energy proposes total expenditure of \$22.9 million over CPP period and \$38.3 million over the review period.<sup>73</sup> The primary objective identified by Aurora Energy is to maintain the safety of the network.

Based on our assessment of the CPP proposal and supporting materials over the CPP and review periods, the forecast modelling approach, forecasts for the crossarms replacement over the CPP and review periods and the assumed unit rate appear consistent with the expenditure objective. The top-down efficiency adjustments included in the forecasts appear reasonable.

Aurora Energy's forecast replacement rate of 5% per annum – total volume included in the poles, crossarms, distribution conductor and LV conductor replacement programs – over the CPP and review periods is much higher than the replacement rates of between 0.72% and 0.96% per annum for the compared Australian businesses. This is mainly due to Aurora Energy's apparent historical underspending on crossarms renewals and the present day need to manage safety risk.<sup>74</sup> While there is a potential for the replacement quantities to be above the forecast once better informed by condition, Aurora Energy's forecast for the CPP and review periods targeted at safety risk concerns is not unreasonable.

### ***Renewals – Distribution conductors***

The distribution conductor renewals program covers conductors' replacement due to deterioration of asset condition. Aurora Energy initiated this renewal program from RY20; there was no dedicated distribution conductor renewal program prior to that – they were previously low in volume and included within reactive work, overhead distribution equipment renewal or entire feeder replacement projects.

Aurora Energy proposes total expenditure of \$16.2 million over the CP period and \$28.1 million over the review period. The primary objective identified by Aurora Energy is to maintain the safety of the networks.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the LV conductor replacement do not appear inconsistent with the expenditure objective over the CPP and review periods.

### ***Renewals – LV conductors***

The LV conductor renewal program covers conductors' replacement due to deterioration of asset condition. This is a new program that Aurora Energy proposes to initiate from RY22. Current practice is to include LV conductor replacements within reactive work, overhead distribution equipment renewal or entire feeder replacement projects given the very low or negligible historical volumes.

Aurora Energy proposes total expenditure of \$10.6 million over the CPP period and \$19.6 million over the review period. The primary objective identified by Aurora Energy is to maintain the safety of the networks.

Based on our assessment of the CPP proposal and supporting material, the supporting material, the forecasts for the zone substation buildings do not appear inconsistent with the expenditure objective for the CPP and review periods.

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<sup>73</sup> These values are net of top-down efficiency adjustments of \$0.6 million and \$2.0 million over the CPP and review periods respectively.

<sup>74</sup> Aurora Energy advises that this underspend contributes to its current safety risk concerns.

### ***Renewals – Zone substations***

Aurora Energy proposes total zone substation expenditure of \$26.5 million over the CPP period and \$41.9 million over the review period. It is made up of four main asset fleets, which we discuss below.

### ***Renewals – Zone substation buildings, grounds and ancillary***

This component of the zone substation renewal program covers buildings, grounds and ancillary equipment. The buildings house the indoor switchgear and secondary systems equipment; the grounds include fences, access ways, security and switchyard earthing; and ancillary equipment includes load management systems, capacitor banks and the mobile substation.

The replacement program includes upgrades to buildings and civil infrastructure that do not currently fully comply with the National Building Standard for the IL3 standard. The building cost component is embedded within the overall zone substation category.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the zone substations do not appear inconsistent with the expenditure objective over the CPP and review periods.

### ***Renewals – Zone substation power transformers***

The power transformer renewal program covers power transformers, bunding, oil containment, firewalls and neutral earthing transformers. The power transformers cost component is embedded within the overall zone substation category. The primary objective identified by Aurora Energy is to maintain the reliability of the networks.

Aurora Energy appropriately uses a risk-based renewal model to forecast the timing need for transformer replacements and then a coordination approach to bundle work into specific zone substation projects.

Based on our assessment of the CPP and review periods, we identified inconsistencies in the mapping of input data in the renewal model that results in the model forecasting earlier timing for replacements than is likely to be justified. The renewal model forecast 19 transformer replacements to RY26 whereas our adjusted model forecast the need for only 11. However, Aurora Energy reduces its forecast replacements from 19 to 11 to RY26 through the project coordination and deliverability process – which means that the inconsistencies do not impact the validity of the forecast volumes.

Aurora Energy had deferred the replacement of two Smith Street transformers beyond the review period even though the condition of these units indicated a worse condition than other units that were included in the period. Aurora Energy explained that this substation has available capacity through interconnection with other supply options and hence the consequence of failure is lower.

Even though the modelling approach and forecasts for power transformer renewals appear to be overstating requirements, the adjustments made in the coordination model have corrected the actual replacements – we consider that the CPP proposal and supporting material, on balance, are consistent with the expenditure objective.

### ***Renewals – Zone substation indoor switchgear***

The indoor switchgear renewal program covers 6.6 kV to 33 kV indoor switchgear within zone substation buildings. The indoor switchgear cost component is embedded within the overall zone substation category. The primary objective identified by Aurora Energy is to reduce worker safety and performance risks of the network.

Aurora Energy appropriately uses a risk-based renewal model to forecast the timing need for indoor switchgear replacements and then a coordination approach to bundle work into specific zone substation projects. Aurora Energy's renewal model design appears valid, noting the limitation that asset health is based on age compared to expected life and the limitation of using test results to estimate probability of failure. The model design should be improved or replaced once better asset condition data is available.

Six 11 kV indoor switchboards were identified by Aurora Energy for replacement based on priority over the review period; however, the South City 11 kV indoor switchboard replacement project was chosen ahead of the Smith Street 11 kV switchboard initially during the coordination process. Following discussions with Aurora Energy the Smith Street switchboard was brought forward and the South City switchboard deferred to beyond RY26. Several factors supported this change including the deferral of some growth projects, which freed up resources.

The expenditure forecast for the indoor switchgear replacement over the CPP and review periods appears consistent with the expenditure objective. To form this view we assessed the CPP proposal, supporting material and discussed these with Aurora Energy staff, including on the adjustments to the Smith Street and South City indoor switchboards.

### ***Renewals – Zone substations outdoor switchgear***

The outdoor switchgear renewal program covers circuit breakers, air-break switches and reclosers located in outdoor switchyards. The outdoor switchgear cost component is embedded within the overall zone substation category. The primary objectives identified by Aurora Energy is to reduce safety and reliability related risks of the networks.

Based on our assessment of the CPP proposal and supporting material, the forecasts for the outdoor switchgear replacements over the CPP and review periods appear consistent with the expenditure objective.

### ***Renewals - LV enclosures***

The LV enclosures renewal program covers above ground and below ground LV enclosures. Aurora Energy initiated this renewal program in RY20. There was no dedicated renewal program for this asset fleet prior to that.

During the verification process, Aurora Energy reduced its total expenditure forecasts over the CPP and review periods to \$5.8 million and \$9.0 million respectively. The primary objective identified by Aurora Energy is to public safety, particularly for enclosures on ground level located in the public domain that have heightened risk for potential serious injury or death.

Up until recently, Aurora Energy has had limited historical data on the condition of its LV enclosures and so relied on assumed ages to prepare its LV enclosure replacement forecasts. Inspections of the fleet during RY19 and RY20 has allowed Aurora Energy to compile reasonable asset condition, which it has subsequently used to inform its risk assessment of the fleet and its replacement forecasts.

Based on our initial assessment of the available information:

- We did not agree with the age-based modelling approach adopted by Aurora Energy for its renewal program forecast without some degree of validation of an initial 40 year expected life chosen for above ground enclosures. The practices of other New Zealand EDBs could have better informed this assumption.
- We considered that the forecast replacement expenditure was inconsistent with the issues and hazards found on review of the inspections completed. The expenditure was also much higher than comparable

other New Zealand EDBs. We agreed that all the underground link boxes require replacement by RY26 but did not agree that all of the P160/P260 type required replacement by RY26.

Aurora Energy acknowledged the findings and adjusted the expected life input parameter in MOD18 (23 April 2020) to 47.5 years, which produced a revised replacement volume more closely aligned the inspection data findings.

In our view, the revised expenditure forecasts for the LV enclosure replacements over the CPP and review periods appear consistent with the expenditure objective. We formed our view after reviewing the CPP proposal (including the updated forecasts) and the supporting material and clarifications provided by Aurora Energy.

### ***Renewals – Protections***

The protection renewal program covers Aurora Energy's electromechanical relays, and static relays and microprocessor electronic types. Aurora Energy proposes total expenditure of \$6.6 million over the CPP period and \$9.3 million over the review period. Aurora Energy initiated this renewal program from RY19. The primary objectives identified by Aurora Energy are to reduce network safety risks and to protect its networks assets.

Based on our assessment of the CPP proposal and supporting material, the forecasts for the protection renewals over the CPP and review periods appear consistent with the expenditure objective.

### ***Growth – Arrowsdown 33 kV ring upgrade***

Aurora Energy proposes total expenditure of \$5.4 million over the review period (and none over the CPP period) to upgrade the Arrowsdown 33 kV ring to address capacity constraints and reliability concerns in the area.

Although there appears to be a need for the Arrowsdown 33 kV ring upgrade given that it is currently operating above firm capacity, the economic case for making the investment depends on the projected demand being realised. If it is not, then it may be economically sound to defer the project until it is.

Given the heightened demand uncertainty created by the COVID-19 pandemic, we consider that the economic case for this investment *is* contingent on demand growth being realised. As such, the Arrowsdown 33 kV ring upgrade could be considered a contingent project.

Based on our assessment of the CPP proposal and supporting material, the proposed expenditure for the Arrowsdown 33 kV ring upgrade over the CPP and review periods appears consistent with the expenditure objective. However, we also consider that the full \$5.4 million could be considered a contingent project given that the demand projections that underpin the economic assessment for it will likely be affected by the COVID-19 pandemic.

### ***Growth – Riverbank zone substation upgrade***

As Aurora Energy no longer proposes to undertake the Riverbank zone substation upgrade project over the CPP or review periods, we have not provided a view on whether it satisfies the expenditure objective. Our draft position was that it did not.

However, as with the Arrowsdown 33 kV ring upgrade project, the project should nevertheless be considered as a contingent project. Our review of the project is contained in section C.14.

### ***Other capex – Connections expenditure***

Aurora Energy proposes total expenditure of \$11.4 million over the CPP period and \$22.6 million over the review period.

Aurora Energy has included expenditure on a major tourism operator's connection upgrade to start in RY25. Aurora Energy has only had initial discussions with the operator and developed an initial customised cost estimate, and at this stage the upgrade is not committed. The COVID-19 pandemic is likely to dampen demand for tourism activities and the financial performance and position of the operator, at least in the short term. It is unclear what, if any, effect this will have on the demand by the operator.

In our view, Aurora Energy's consumer connections expenditure appears consistent with the expenditure objective based on the information reviewed. However, given the need for the major tourism operator's connection upgrade (and other connections) is contingent on formal connection requests being made, that component of the expenditure forecast (\$2.1 million over the review period) should be considered as a contingent project.

### ***Non-network capex – ICT***

Aurora Energy proposes total expenditure of \$9.2 million over the CPP period and \$12.2 million over the review period.

ICT capex covers the costs of supporting and enhancing infrastructure, information services and applications that support Aurora Energy's system operations and business support. This work has already commenced – and will be largely completed by the commencement of the CPP period.

In our view, Aurora Energy's forecast ICT capex for the CPP and review periods does not appear inconsistent with the expenditure objective based on the information that we have reviewed. Given that business-wide benefits are expected to flow from this expenditure, we would expect to see some efficiencies across other projects and programs, especially later in the CPP and review periods – as reflected in Aurora Energy's proposed top-down efficiency adjustments.

## **4.5 DELIVERABILITY**

### **4.5.1 Aurora Energy's proposal and our general observations**

Aurora Energy is now addressing the increasing and heightened network risk due to years of imprudent asset management decisions and inefficient service delivery allowed by the deficiencies in its historical organisational set-up and contractual model.

In 2017, Aurora Energy introduced the FTTP – which involved rapid expenditure delivery – with additional new contractors to address such heightened network risk. Aurora Energy's experience with the FTTP informed the service delivery change that it has embarked upon recently. This involved establishing short term commercially binding FSA arrangements with three contractors (Unison in Dunedin region, Connetics in Central region, and Delta in both regions), and relationship contracts with an additional three contractors to participate in open tenders for larger projects.

Aurora Energy's CPP proposal aims to further reinforce and support the changes to its contractual arrangements, procurement standards, strengthening of relationships with its service providers and work planning to realise the benefits. It aims to evolve this arrangement over time, with an increasing focus on benchmarking unit rates and introducing new incentive arrangements to ensure that the service provision from the market remain competitive. The existing FSA arrangements are in place until March 2022 and

Aurora Energy aims to establish similar/efficient contractual arrangements thereafter incorporating service delivery performance improvements.

Aurora Energy has also engaged an independent engineering consultant to review the unit rates in its pricebook that forms the basis for estimating capital costs.

#### 4.5.2 IM requirements and our approach to assessment

This section aims to address Schedule G5(1)(e) of the IM, and our approach to assessing compliance of Aurora Energy's CPP against the IM requirements.

##### Box 11 – IM requirements for capex deliverability

###### Schedule G5(1) of the IM:

The verifier must-

...

- (e) provide an opinion as to overall **deliverability** of work covered by the **capex categories in the next period**;

Our approach to assessment was to examine at an aggregate program level, along with review of the identified projects and programs, Aurora Energy's preparation for its proposed expenditure delivery. We reviewed the proposed uplift in the work to be outsourced during the CPP and review periods, internal and external capability and capacity required to efficiently deliver such works, and the expected market forces at play in the South Island competing for similar resources during these periods.

We reviewed the existing FSA set-up for competitive tension provision, arrangement for performance feedback, the visible pipeline of proposed work within the annual committed expenditure (ACE) limit for each FSA contractor and outside the limit (i.e. open tender work) for sustainability, metrics for key performance indicator (KPI) measurements, and the FSA contractors' commitment in maintaining a sufficient level of resources to deliver the work.

We also considered the nature of resources, tools, system and data required within Aurora Energy to effectively plan, manage, contract and administer the proposed volume of work. This involved us understanding the features of Aurora Energy's new project management tool Sentient PPM, its plan to further expand its functionalities (for e.g. investment prioritisation), accredited project management training and capacity, and reviewing position descriptions of various crucial existing roles and planned recruitments. During the workshops and discussions with Aurora Energy we identified and discussed the potential gaps or risks in relation to the resource availability.

#### 4.5.3 Our findings

In our view, the work proposed in the capex forecasts over the CPP and review periods does not appear undeliverable, with some limitations.

Although on-the-ground systems, processes and resources are all being established and new contractual arrangements implemented, there are risks around management bandwidth and the challenging timeframe assumed in the forecasts to mobilise projects and programs given the significant step up in proposed activity in some areas and the wide-range of initiatives. This is even more so given that the COVID-19 pandemic is likely to undermine delivery during RY21 and potentially for longer.

We note that delivery risks could result from:

1. system and process changes creating challenges for internal resources – Aurora Energy is most of the way through a planned significant increase in internal resources for some expenditure categories and based on our experience, establishing new teams on such a large scale while implementing new systems and process can lead to some lost productivity, albeit this is often temporary
2. events like the COVID-19 pandemic affecting ability to undertake non-essential work – given the current restrictions in place, it is likely that delivery of work in RY21 will be compromised to some degree; if these restrictions or other implications from the pandemic persist (e.g. ability to source labour or equipment), then the work program forecast for the CPP and review periods may also be compromised
3. Aurora Energy potentially awaiting the Commission’s final determination before ramping up some activities in full – this may affect the timing of such activities, especially if they have long lead times, although we understand that Aurora Energy currently intends to ramp up for its planned investments.

However, we consider that Aurora Energy can manage the above risks.

Aurora Energy has analysed its internal skill and resource gaps and has actively started addressing the identified gaps. We are satisfied with the progress made so far in implementing the project management systems, training and building the capability and capacity of the relevant teams. For example, a new role of contractor performance manager has been created and filled to administer the FSA contracts, monitor the performance and implement the feedback to determine contract terms and work volume etc. Aurora Energy is presently establishing an engineering consultancy panel to outsource complex design works.

Aurora Energy has developed coordination tools and considered levelising work over the CPP and review periods to provide a manageable and steady flow of work packages to its service providers. These processes and challenges made at executive level are likely to be beneficial to work delivery efficiency.

Aurora Energy has not analysed potential constraints due to external market factors in its region competing for similar resources. However, based on our discussion with Aurora Energy’s executive we are reasonably satisfied that they have taken steps to ensure that these risks can be managed effectively. Aurora Energy’s FSA contractual set-up and the additional contractors for the open tender participation appear to provide Aurora Energy with sufficient flexibility in outsourcing work.

## 4.6 ASSET REPLACEMENT MODELS

### 4.6.1 Aurora Energy’s proposal and our general observations

Aurora Energy developed several different approaches to model its assets and forecast replacement volumes and expenditure. The general methodologies<sup>75</sup> applied in the models are:

- **Probabilistic models** – using historical data to develop survivor curves then forecasting replacement based on asset population. These are generally considered GEIP when applied appropriately. Aurora Energy has applied this method to the pole renewal program.
- **Condition based models** – using actual condition inputs to determine individual asset health and forecast replacement date. These are generally considered GEIP when applied appropriately and provided the input data is accurate and reliable with a known correlation to asset failures. Aurora Energy applied this method to the power transformer renewal program (zone substations).

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<sup>75</sup> All modelling approaches can provide a measure of asset health (AHI) but with different degrees of confidence.

- **Age based models** – used age as the key determinant for asset replacement. This was implemented both as a deterministic approach and as the basis for modelling asset performance. These are generally not considered GEIP but are acceptable when no other data is available, and consideration is given to historical trends. Typically, this occurs for high-volume low-cost assets when they are first entering a phase of age-related failures, which currently is typical for many network businesses. Aurora Energy is using this approach for most of its renewal program:
  - crossarms, HV and LV conductors, LV enclosures, indoor switchboards and outdoor circuit breakers
  - after data becomes available through 100% inspection or otherwise by sampling the model can be advanced to probabilistic modelling or models partly informed by condition
  - the use of this approach by Aurora Energy for these assets is consistent with industry practice except to the degree others have advanced their models.
- **Trending models** – to forecast future performance, volumes or expenditure based on the continuation of historical trends or on a per unit basis to provide a relationship to changing work practices in the future. These are generally considered GEIP when applied appropriately. None of these were used by Aurora Energy in the identified renewals programs.

Other methods used in renewal programs include:

- **Consolidation (or coordination) models** – are used to bring together forecasts from multiple related assets, adjust timing to address asset specific issues and calculate the final volumes and expenditure. Aurora Energy used a coordination tool for bundling work into zone substation renewal projects.
- **Discounted cash flow models (supporting business cases)** – can be used to compare project options (asset strategies) on a financial basis. Aurora Energy did not identify the use of any of these methods to review renewal program options.
- **Asset risk management models** – are used to consider asset failure modes and consequences to consider alternate intervention strategies (options) and/or used to optimise replacement priority. Aurora Energy has used risk management models only for replacement priority.

The models for each project and program reviewed were assessed in detail and the specific outcomes are set out in Appendix D. Section 4.6.3 sets out our findings.

## 4.6.2 IM requirements and our approach to assessment

This section aims to address Schedule G5(1)(f) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

### Box 12 – IM requirements for asset replacement models

#### Schedule G5 of the IM:

The verifier must-

...

- (f) provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the **capex forecast** including an assessment of-
  - (i) the inputs used within the model; and

(ii) the methods the **CPP applicant** used to check the reasonableness of the forecasts and related expenditure.

Our approach to assessment of the models is:

- identify the models used to justify each of the key projects or programs and / or to support overall network performance
- review the appropriateness of the methodology utilised in each of these models against good practice, appropriateness for the asset type, and those likely to promote the expenditure objective
- identify the inputs to the model, investigate if the data source was appropriate, and how the inputs relate to key assumptions
- consider any relationships between the opex and capex forecasts and how these have been incorporated into the method or methods, or not
- review any methods used by Aurora Energy to check the reasonableness of its capex forecasts.

### 4.6.3 Our findings

We have separated our findings into an overall assessment of the methodologies applied, how the models were implemented, the inputs used, and the validity of outputs. A review of each model is provided in Appendix D of this report. For validation of the residual risk (safety and reliability) we used benchmarking with peer organisations in the absence of risk assessments conducted by Aurora Energy.

#### *Forecasting methods*

In our view, based on our assessment in relation to the CPP proposal, the overall approaches to asset replacement modelling do not appear unreasonable given the current maturity of Aurora Energy's management systems and generally quite limited availability of data.

The methods chosen for each asset program generally aligns with GEIP. As with all age-based methods there is an inherent likelihood that expenditure can be under- or over- stated due to assumptions about the expected asset life when intervention is required before failures occur.

Age based renewal models for crossarms, HV and LV conductors are based on assumed expected lives to generate a forecast for which the actual assets in need will be later confirmed through inspections. In each of these cases we have used benchmarking with peer organisations to assist in verifying the model outputs, and hence the validity of the age assumptions.

Overall, the methods used to forecast the renewal capex are reasonable based on the data and knowledge of asset condition (where available) and asset attributes (age profile).

#### *Forecasting models*

The forecasting model is how the forecasting method described above is applied and includes the software tool used (typically MS Excel), the structure of the model and formulae applied.

Key aspects of models that support the expenditure objective are:

- most models were well constructed and included cover pages, explanation and separation of inputs, calculations and outputs – this resulted in a reliable and consistent suite of models and provided confidence in their robustness

- the models were not found to have any invalid cell entries or formulae applied that materially had an effect on the forecasts (although we did not undertake full model audits).

In two cases, while the methods may align with GEIP, the input data assumptions or conversion into asset health measures were either not demonstrated or were found to be not appropriate or prudent to use. Our findings are as follows:

- We were unable to verify the initial forecast expenditure for LV enclosures based on assumptions used in the data model, including expected life and assumed risks, and based on our benchmarking with peer organisations. The model also should have separated age related failures to random failures due to third parties. Aurora Energy acknowledged our findings and accordingly adjusted its final forecasts.
- In our opinion, an error found in the transformer risk-based renewal model has overstated the need to replace 19 transformers from RY21 to RY26 instead of 11 transformers. However, despite this error, Aurora Energy reduced the 19 units to 11 units during the coordination modelling process. While this appears to be coincidental, it is important to raise the matter of this issue with the model.

### *Model inputs*

The inputs are the data used by the model to calculate the forecast volume and expenditure. This can include network data extracted from databases, outputs from other models and assumptions.

Key aspects of the use of data inputs that support the expenditure objective are that, in general:

- historical or market unit rates have been used to calculate the expenditure forecast
- actual network data was used, where available, to identify trends or calculate input values rather than making assumptions.

Key aspects of the use of data inputs that do not support the expenditure objective are:

- no allowance was made for wood pole reinforcement in the future, especially from RY25 onwards by which time we believe that Aurora Energy would be in a good position to implement this strategy to defer some renewal expenditure on its ageing wood pole population
- while the inspection data for LV enclosures was limited during the development of the corresponding model, the subsequent inspection reports and condition data indicate that adjustment to the model or method is needed. Either the input data for expected life is increased or preferably defect rates discovered through inspection is used in probabilistic models similar to poles. This model should include allowance for random failures due to third parties.

## **4.7 RENEWALS – PERFORMANCE MEASUREMENT**

Other than AHI-based targets, there are no performance objective or targets set for Aurora Energy's renewal program largely due to concerns over historical data quality. Aurora Energy plans to improve the capture and analysis of fault and defect data across its renewal program to support ongoing performance monitoring over the CPP period. Such measurements will allow improvements to Aurora Energy's renewal asset strategies and be utilised to drive asset management improvements and provide better informed expenditure forecasts.

The absence of specific asset class performance measures and targets, while acknowledging Aurora Energy intends to implement these, establishing interim targets would have provided a degree of understanding of prudent levels of residual risk (safety as the key focus) and would have assisted in decision making for each renewal program.

The Commission may wish to discuss the establishment of interim measures and targets for the CPP period which would assist in understanding the residual risk and provide line of sight to the Quality Standards, potentially both reliability and safety measures.

## 5. Operating expenditure

In this chapter, we assess Aurora Energy’s forecast opex against the expenditure objective and the schedule G IM requirements. This required us to:

- form a view on Aurora Energy’s policies and planning approaches, assumptions, drivers, forecasting methodologies, and forecast models
- summarise our conclusions from a detailed review of identified opex programs and projects.

This chapter is structured as follows:

Heading	Sets out
Section 5.1	Findings on Aurora Energy’s forecast opex against the expenditure objective
Section 5.2	Findings on Aurora Energy’s policies and planning standards as they relate to its forecast opex
Section 5.3	Findings on key assumptions underpinning Aurora Energy’s forecast opex
Section 5.4	Findings on drivers underpinning Aurora Energy’s forecast opex
Section 5.5	Conclusions from our review of identified opex programs and projects
Section 5.6	Findings on any opex reduction initiatives proposed by Aurora Energy
Section 5.7	Findings on the deliverability of Aurora Energy’s forecast opex
Section 5.8	Findings on the models and forecasting methods used by Aurora Energy to develop its forecast opex

### 5.1 EXPENDITURE OBJECTIVE

#### 5.1.1 Aurora Energy’s proposal and our general observations

Aurora Energy proposes opex over the CPP period of \$154.1 million, or \$249.9 million over the review period, as summarised in Figure 5.1.<sup>76</sup> This compares to \$185.4 million expected over the previous five-year DPP period (RY16 to RY20) – an annual increase of \$14.3 million (38.6%) over the CPP period, or \$12.9 million (34.8%) over the review period.

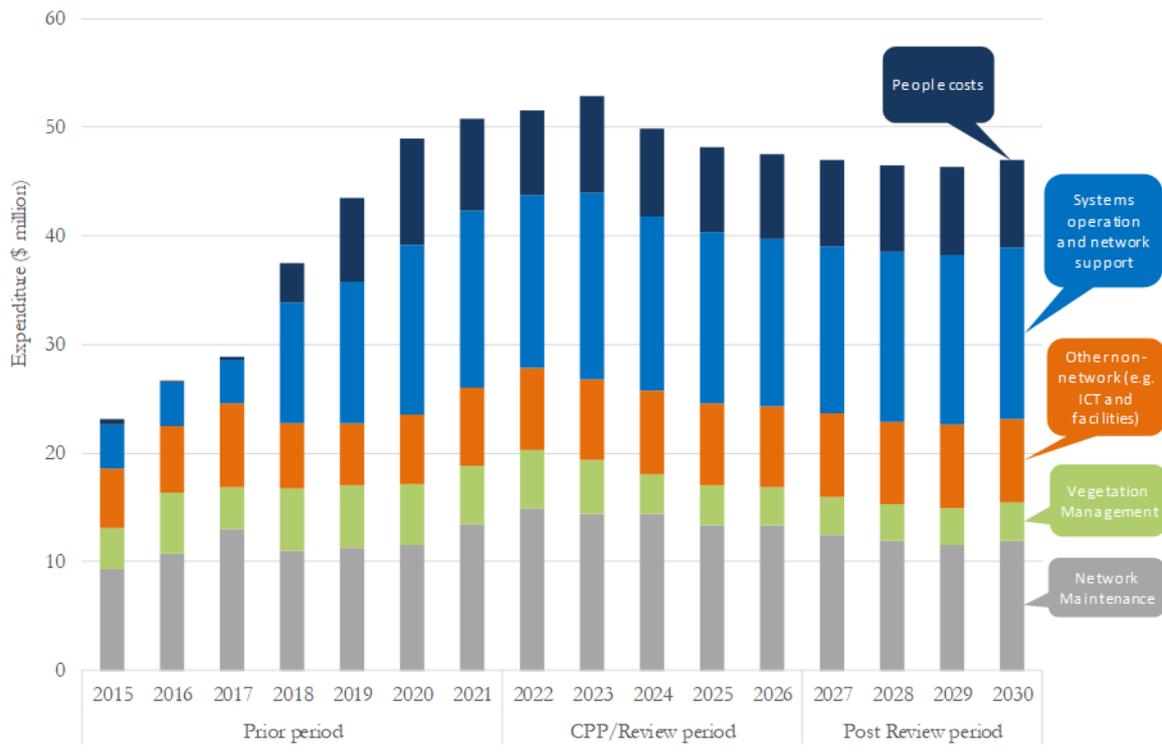
As with capex, the opex forecasts represent a significant uplift in expenditure relative to the RY15 to RY19 period. We acknowledge that Aurora Energy is on a path of improvement with its asset management practices and business support capability and that it needs to:

- address WSP’s findings on the state of its network
- manage deteriorating network condition and a backlog of maintenance work.

These drivers support an increase in expenditure from current levels. The question for our review is whether the increase proposed by Aurora Energy is appropriate in the circumstances when assessed against the expenditure objective.

<sup>76</sup> All values in this report are in real \$2020, unless otherwise stated. These values are often identified as ‘\$2020’ for short. All values exclude cost escalation, unless otherwise stated. We consider cost escalation separately in section 6.4.

Figure 5.1 – Opex forecast (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

The proposed increase in expenditure relative to the RY15 to RY19 period is principally due to:

- a drive to move from a reactive to proactive maintenance approach, including by addressing an apparent maintenance backlog and issues identified by WSP about incomplete historical work
- a related focus on improving data quality and asset condition assessments to support
- a change in approach to vegetation management, including an initial period of catch up cutting
- additional capability and capacity added to Aurora Energy’s systems operations and business support activities, including to support the proposed increase in capital and operating activities
- a strategy to return pre-1984 consumer poles to consumer ownership after ensuring that they are in a good condition
- plans for a further CPP application covering the five-year period from RY25.

### 5.1.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(2) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

### Box 13 – IM requirements for opex overall

#### Schedule G6(2) of the IM:

Based on analysis in accordance with this clause, the **verifier** must provide an opinion on whether the **CPP applicant's** forecast of total opex meets the **expenditure objective** and, if not, identify-

- (a) whether the provision of further information is required to enable assessment against the **expenditure objective** to be undertaken and, if so, the type of information required;
- (b) which of the **CPP applicant's** forecast **opex programmes** for each **opex category** might warrant further assessment by the **Commission**; and
- (c) what type of assessment would be the most effective.

We assessed Aurora Energy's proposed opex against the requirements set out in Schedule G of the IM, which we detail further below. This involves assessing:

- Aurora Energy's policies and planning standards and how these applied in developing the forecast expenditure
- the key assumptions and drivers that underpin the forecast expenditure and the models used to derive those forecasts
- selected operating programs
- any proposed expenditure reduction initiatives
- the deliverability of the forecast expenditure.

#### 5.1.3 Our findings

Aurora Energy has used the base-step-trend approach to generate most of the opex forecasts, using RY19 as the base year.<sup>77</sup> We consider that this is a valid and reasonable method for forecasting opex, recognising that the underlying premise for it is that the revealed base year includes all efficient costs that a prudent operator would incur. Given Aurora Energy's operational maturity, some of the maintenance, SONS and people costs step changes (above the RY19 opex) we characterise as base year expenditure that a prudent operator would likely incur.

We also consider that most of Aurora Energy's opex forecast does not appear inconsistent with the expenditure objective. However, we have formed the view that Aurora Energy's opex forecasting and supporting assumptions for the CPP and review periods do not fully meet the expenditure objective, because:

- **Maintenance base year may not be efficient.** Although Aurora Energy's base year maintenance expenditure is not statistically different from that of selected comparable New Zealand EDBs, such benchmarking is inconclusive and there are other reasons to suggest that these costs may not be efficient. Initiatives introduced since RY19 such as the new FSA agreements, and the introduction of asset management improvements may reduce inefficiencies inherent in the base year that would include

<sup>77</sup> Of the opex programs that we verified, the two exceptions to this are vegetation management – which was forecast using a volumes time quantity basis – and ICT opex – which was forecast using a bottom up build of the costs for the proposed ICT solutions.

practices identified by WSP as being inadequate. Further reductions may also be possible to reflect on-going productivity improvements (e.g. from investment in ICT, SONS and people costs).

To better understand the potential impact of the such initiatives, it would be appropriate to review actual RY20 maintenance expenditure when available to determine what, if any, efficiencies may have been achieved in the first year of the FSA and use this to inform whether the base year should be adjusted or not.

- **Vegetation management unit rate does not appear efficient.** The unit rate used to forecast vegetation management costs appears inefficient based on the information available. Aurora Energy has relied upon historical costing to establish all-inclusive rate per km, including liaison and cutting costs. Although limited, benchmarking against EDB peers using publicly available data suggests that the rate is high.

Aurora Energy's past annual vegetation spend appears significantly larger than comparable EDBs that have more affected kilometres. Aurora Energy's historical costs appear to be outliers, appearing approximately 40% higher than the confidence interval around the trendlines for comparing costs per overhead circuit kilometre against related SAIDI and overhead circuit lengths. However, similar benchmarking against Australian DNSPs shows Aurora Energy's costs per kilometre compares favourably, although is likely affected by differences between Australia and New Zealand operating environments, vegetation management practices, and regulatory reporting instructions.

In our view, the benchmarking suggests that Aurora Energy's proposed unit rate may be too high; but is not conclusive in identifying a potential adjustment. One approach to identifying such an adjustment draws from Aurora Energy's proposed top-down efficiency adjustments – where it is proposing these start at 0.5% in RY22 and increase to 8.5% by RY26. Aurora Energy's new trimming / cutting approach will be in place by RY22 and there appears to be a credible threat that it could go to market for vegetation management services, which will likely support meaningful efficiencies from that time. If the 8.5% efficiency adjustment applied from RY22, then forecast vegetation management expenditure would be \$0.8 million lower over the CPP and review periods.<sup>78</sup> Absent other information, we have adopted this value as the unverified amounts for the program over the CPP and review periods. Obviously, larger or smaller efficiency adjustments would increase or decrease the unverified amounts respectively.

We recommend that the Commission and Aurora Energy discuss the scope for efficiency improvements further.

- **Network growth applied to expenditure is inappropriate over the CPP and review periods.** Aurora Energy has adopted the output growth factor used in the DPP when applying the base, step and trend approach. Although such a trend may be appropriate when assessing opex in aggregate, such a trend factor is not always appropriate for specific expenditure categories over given periods. In the current case, it does not appear appropriate for corrective and reactive maintenance, SONS, and people costs because the key drivers are either specific maintenance concerns or network scale has already been factored in (e.g. when establishing SONS and business support functions from scratch). For those categories, the assumed trend contributes \$2.5 million over the CPP period and \$5.3 million over the review period.
- **Insufficient information to justify some step changes.** After we provided our draft report, Aurora Energy provided additional supporting information for the proposed step changes in the network maintenance, SONS, and people costs portfolios. This information supported the step changes for the most part – and so we consider them verified.

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<sup>78</sup> Aurora Energy is not bound to continue using Delta to provide vegetation management services. Aurora Energy advised that it may consider going to market for other service providers if it is not comfortable with Delta's performance. This poses a credible threat to Delta that it will need to perform if it wants to be retained.

The three exceptions are step changes for:

- a 10% increase in defects requiring corrective maintenance over the CPP and review periods – in our view, while a net increase is possible, there was insufficient support for the value, including as to what effect introducing a defect grading system may have
- an increase in insurance premia – given the significant effect that the COVID-19 pandemic is having on insurance markets, it is unclear whether the projections proposed by Aurora Energy that were prepared before the pandemic took hold are appropriate
- an increase in training costs – although an increase in employees would likely lead to an increase in training costs, we did not see sufficient information to justify the proposed increase in training costs *per employee*.<sup>79</sup>

These total \$1.8 million in the CPP period and \$3.1 million for the review period.

- **Opex reduction initiatives appear modest.** Aurora Energy has applied top-down efficiency improvement adjustments to the network maintenance, SONS, and people costs forecasts to reflect the impact that other initiatives in the capex and opex portfolios are expected to have during the CPP and review periods. These adjustments differ across the opex programs and vary year-on-year, with efficiency improvements projected to ramp up from the start of the CPP period.

Aurora Energy explains that the top-down adjustments cover:<sup>80</sup>

- increased competitive tension and efficiencies that could be realised by the uplift in work associated with the CPP
- possible improvements as Aurora Energy moves from addressing spot risks to fleet-wide risks
- asset management improvements, including expanded network analytics using better data; investment optimisation; and condition-based risk management
- improvements as Aurora Energy matures its systems and processes.

Across the opex portfolios that we reviewed, the top-down adjustments reduce forecast expenditure by \$0.9 million and \$3.0 million over the CPP and review periods respectively, reflecting Aurora Energy's proposed gradual ramp up in efficiencies over the period. No adjustments were applied to the opex portfolios that we did not review.

Given the scope of Aurora Energy's proposed expenditure and changes to the way that it works, applying top-down efficiency improvements is reasonable. However, in our view, the percentage allowances (in aggregate) appear modest. Based on our experience, benefits from the new contracting arrangements and improved systems and process can be significant and realised relatively soon after they are in place.

Although we have not determined alternative top-down adjustments, we recommend that the Commission work with Aurora Energy to better understand what efficiency improvements could be expected over the CPP and review period from the proposed expenditure.

Together, these concerns are likely to result in forecast opex being too high, which we consider unverified, up to approximately \$5.0 million and \$9.2 million over the CPP and review periods respectively – or roughly 4% of Aurora Energy's forecast opex.

We also expect that proposed investment in ICT systems and improved asset management maturity and the new contracting arrangements will likely lead to some efficiency improvements. Apart from a

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<sup>79</sup> Aurora Energy proposes increasing training for its staff during the CPP period, with costs increasing from \$1,235 per staff member in RY19 to \$2,735 per staff member in RY22. Whilst we accept that the additional training may well be justified, we have been unable to verify the significant increase in cost per person, or the need or justification for the additional training.

<sup>80</sup> Aurora Energy, *Notes regarding the Forecast Tracker and Forecast Efficiency Calculator*, 1 May 2020.

proposed contractor related efficiency step change for reactive maintenance, Aurora Energy does not appear to have included any other efficiency or productivity improvements into its opex forecasts.

There are interdependencies between the various maintenance expenditure programs that have not been reflected in the expenditure forecasts. Although Aurora Energy has included a reduction in reactive maintenance from improved condition (qualitatively linked to renewal expenditure), we could not validate that the assumed efficiencies adequately address the interdependencies.

Finally, Aurora Energy capitalises labour costs and other support costs where they contribute to creating or bringing a new asset to service, which may include SONS and people costs. Aurora Energy advises that its opex forecasts include only the expensed portion of those costs. However, we could not confirm what capitalised SONS and people costs Aurora Energy is forecasting for the CPP and review periods, and therefore whether they are consistent with the opex forecast.

The reasons for our view and findings are discussed in the following sub-sections, and are informed by our detailed review of opex projects and programs contained in Appendix C. We also separately consider Aurora Energy's proposed cost escalation of its capex and opex forecasts in section 6.4.

#### 5.1.4 Completeness and key issues for the Commission

The information provided by Aurora Energy – and the related workshop sessions – on its proposed opex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As noted above, we have identified several concerns with key aspects of the Aurora Energy opex forecasts. When undertaking its own assessment of the information, we recommend that the Commission focus on:

- **Network maintenance and vegetation management** – engage with Aurora Energy on its assessment of the efficiency of historical maintenance and vegetation costs, including any market testing or benchmarking that may be available to assess the efficiency or otherwise of the historical costs, and any potential efficiency gains that may be available through the new FSA arrangement with three contractors.
- **Consumer poles** – engage with Aurora Energy to review the current status of the consumer pole population, with a particular focus on those pre-1984, and assess Aurora Energy's proposed timing to undertake maintenance work (and any associated replacements) on them during the CPP and review periods.
- **Trending for opex categories** – the Commission may wish to consider whether it is appropriate to apply a general network growth trend to individual expenditure categories, especially where network growth is unlikely to drive costs for some categories over the CPP and review periods.
- **Cost escalators** – the Commission may wish to procure its own cost escalator forecasts from a sufficiently qualified and independent third party to compare to those proposed by Aurora Energy, especially given the potential impact that COVID-19 pandemic could have on projected costs.
- **ICT benefits** – engage with Aurora Energy to review the expected benefits from the proposed capex and opex initiatives, and how the actual benefits achieved will be captured and reported, especially given Aurora Energy's cost-benefit analysis shows a negative NPV in the first five years from RY21, but a compensating large positive NPV once the next five years are included; this could then inform how what efficiency improvements should be included in any subsequent CPP application.

## 5.2 POLICIES AND PLANNING STANDARDS

### 5.2.1 Aurora Energy's proposal and our general observations

Aurora Energy is currently developing a set of policy and planning documents covering all the core aspects of the business that we would expect in other mature organisations. Aurora Energy provided us with a list of its current policies and planning standards and any specific policies and planning standards that we sought to see.

Based on a review of EDB peers and planning standards in New Zealand, Aurora Energy has developed several new strategies for delivery of its network opex functions, including vegetation management and maintenance. These have contributed to Aurora Energy's proposed step up in forecast maintenance and vegetation management opex over the CPP and review periods relative to the RY15 to RY19 period.

Section 4.2 has more detail regarding the current overall state of Aurora Energy policies and planning standards and the development of these documents as part of the development of an asset management framework. We avoid repeating those words here.

### 5.2.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(1)(a) and (b) of the IM, and our approach to assessing compliance of Aurora Energy's CPP against the IM requirements.

#### Box 14 – IM requirements for policies and planning standards relevant to the opex forecasts

##### Schedule G6(1)(a) and (b) of the IM:

The **verifier** must-

(a) provide an opinion as to whether the–

- (i) **policies,**
- (ii) **planning standards;** and

...

relied upon by the **CPP applicant** in determining the **opex forecast** are of the nature and quality required for that **opex forecast** to meet the **expenditure objective;**

(b) provide an opinion as to whether the **opex forecast** has been prepared in accordance with the **policies** and **planning standards**, at both the aggregate system level and for each of the **opex categories;**

Our approach to assessment was to:

- review the list of policies and planning standards that Aurora Energy has and identify those considered most relevant to developing the opex forecasts
- review the identified policies and planning standards against what we would expect to see for a prudent non-exempt EDB, in terms of both nature and quality
- as part of our review of selected opex projects and programs, review how the policies and planning standards were applied when developing the opex forecasts.

### 5.2.3 Our findings

#### *Nature and quality*

In our view, based on an assessment in relation to the CPP proposal, the bulk of Aurora Energy's policies and planning documents appear of a nature and quality sufficient for the opex forecast to meet the expenditure objective. Overall, the documents are sufficient for the development of the opex forecasts, as they support a maintenance regime based on cyclic/routine preventive maintenance (as shown in section F.2.5).

Aurora Energy is currently updating legacy documents with current or planned practices and re-issuing them as controlled documents that will support asset management practices upon issue. These reference inspection and testing forms that will record the work as it is done, as well as flagging any defects that will need corrective attention.

To date Aurora Energy has updated 63 fleet management related documents (asset maintenance and recording), 17 operations documents detailing safe-working and work permit requirements and 23 documents detailing delivery management, monitoring and project close-out.

Some of these documents are currently rudimentary but sufficient in nature as Aurora Energy enhances its asset management practices as part of the drive for certification to ISO55001 by RY23. However, they do not provide sufficient detail to address the WSP findings from the network review. For example, the monthly substation inspection forms provide for recording asset condition as "OK" or "Needs Attention", so these forms capture some asset condition information. However, they do not provide the opportunity for the inspector to note against the assets any defects identified as requiring attention or what sort or level of defect it is. Aurora Energy does not currently have a defect grading system for many of its assets (the exceptions being poles, crossarms and pole tops) and that its operations staff advised us that a grading system is planned for implementation when the asset management system is introduced – which is a logical sequence, provided the system is introduced shortly. In our view, Aurora Energy should realise long-term efficiencies and reliability improvements once the defects can be properly graded at inspection so that corrective work can be better organised and focused on the defects requiring more immediate attention.

Aurora Energy's updated vegetation management strategy and standard underpin its intention to better plan the cutting work; and to introduce a five yearly cycle for the work by cutting trees in public areas and those designated "Declared No Interest" back further than required by the current Tree Regulations. This should improve the overall efficiency of the vegetation management program.

For completeness, we note that Aurora Energy's capitalisation policy also appears of the nature and quality required for the opex forecast to meet the expenditure objective. Aurora Energy advises that its forecast capitalised internal labour is relatively flat over the CPP and review periods and consistent with RY19 actuals.<sup>81</sup>

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<sup>81</sup> See, for instance, the spreadsheet forecasting capitalised labour costs in: Aurora Energy, *Capitalised Labour - Summary for IV*, 20 May 2020. This shows that capitalised internal labour is expected to make up between 2.6% and 3.1% of gross capex over the CPP and review periods, compared with 2.6% in RY19. Similarly, it shows that capitalised internal labour is expected to make up 13.0% of total employee labour costs over the periods, compared with 12.8% in RY19. Although we have not audited the accuracy of the data provided or validated whether it aligns with the expenditure forecasts that we have reviewed, the spreadsheet suggests that proposed capitalisation over the CPP and review periods is consistent with actual capitalisation in RY19 – and, therefore, the capitalisation policy applied over that year.

### *Application to forecast expenditure*

In our view, based on our assessment in relation to this CPP proposal, Aurora Energy has generally prepared the opex forecast in accordance with the policies and planning standards available at the time and, in some cases, those that it is still developing.

## **5.3 KEY ASSUMPTIONS**

### **5.3.1 Aurora Energy's proposal and our general observations**

Aurora Energy's opex forecast is based on several key assumptions, including that:

- asset maintenance strategies need to be improved to address the WSP findings from the network review
- the asset management capability requires enhancement, leading to ISO55001 certification, which coupled with an increased network investment and analysis focus will lead to network capex and opex investment efficiency to consumers over time
- there is a need to ensure compliance, safety, support for proposed network capex work, and planned asset management, and that the proposed opex (when combined for the proposed capex) will achieve this
- there is a need to adopt a new strategy for vegetation management across the network, including a five-year cutting cycle wherever possible
- with the enhanced inspection programs, it is reasonable to expect more defects to be identified during the CPP and review periods
- Aurora Energy needs to undertake a substantial amount of work to improve the extent and accuracy of asset condition and performance data, to support the implementation of the new asset management system and improved analysis and optimal future investment decision making
- the new FSA model will drive efficiencies in cost and delivery through the use of three service providers for reactive maintenance only, not other network opex programs
- actual RY19 maintenance expenditure and RY18 vegetation management expenditure are efficient and should be used for forecasting future opex, either as base opex for maintenance or to determine the vegetation management unit rate
- provision of new roles within the SONS program will have a net benefit for consumers
- current people costs are not sufficient to deliver the corporate and business services needed to support the network over the CPP and review periods
- there is a need to prepare for a second CPP starting from RY25.

These are explained within the documents provided by Aurora Energy – including in response to questions that we raised – and reflected in the underlying opex forecast models.

### **5.3.2 IM requirements and our approach to assessment**

This section aims to address Schedule G6(1)(a) and (c) of the IM, and our approach to assessing compliance of Aurora Energy's CPP against the IM requirements.

## Box 15 – IM requirements for key assumptions

### Schedule G6(1)(a) and (c) of the IM:

The verifier must

(a) provide an opinion as to whether the–

...

(iii) **key assumptions,**

relied upon by the **CPP applicant** in determining the **opex forecast** are of the nature and quality required for that **opex forecast** to meet the **expenditure objective**;

...

(c) provide an opinion on the reasonableness of the **key assumptions** relevant to opex relied upon by the **CPP applicant** including–

(i) the method and information used to develop them;

(ii) how they have been applied; and

(iii) their effect or impact on the **opex forecast** by comparison to their effect or impact on **actual opex**;

Our approach to assessment was to:

- identify the assumptions relied upon by Aurora Energy to develop its opex forecast
- review these assumptions against what we would expect to see for a prudent non-exempt EDB, in terms of both nature and quality – this included review of the practices that we see other EDBs undertake in relation to preventative, corrective and reactive maintenance, vegetation management and non-network opex
- review the method and information used to develop those assumptions, including any supporting models, business cases or strategy documents
- review how these assumptions were applied, including in the relevant opex forecast model
- consider the effect or impact of the assumptions on the proposed opex forecasts, including by considering their effect or impact on actual opex (where relevant).

### 5.3.3 Our findings

In our view, Aurora Energy’s key assumptions relating to the opex forecast are reasonable, except for the following:

- the efficiency of RY18 vegetation management expenditure has not been fully demonstrated to us
- the efficiency of RY19 maintenance expenditure is unclear to us<sup>82</sup>

<sup>82</sup> As discussed in Appendix C, although the benchmarking that we considered was statistically unclear – and so we did not identify any unverified amount related to base expenditure – other factors indicate that that expenditure may be too high. We recommend that the Commission consider this further when assessing the material.

- moreover, Aurora Energy expects the new contracting arrangement to deliver improvements in preventative and corrective maintenance and vegetation management, but has used historical costs<sup>83</sup> to generate forecasts without factoring in those improvements<sup>84</sup>
- although Aurora Energy has looked to build cost savings into its maintenance opex forecasts to reflect proposed asset renewal expenditure, this is largely offset over the CPP and review periods through an expected increase in defects found from more detailed inspections.

Each exception is discussed further below as part of our review of the selected opex projects and programs.

Our view is also subject to the following limitations:

- The opex by program is adjusted for real input cost escalation based on escalators independently forecast by Sapere<sup>85</sup> – although the approaches used to prepare the labour and materials escalators determined by Sapere for Aurora Energy do not appear unreasonable, they are now out of date given the impact of the COVID-19 pandemic (see section 6.4 for further discussion).
- No obvious forecast productivity improvement or economies of scale efficiencies are included within the rate of change of the base, step and trend method used to forecast most opex categories.<sup>86</sup>

These limitations may warrant further consideration by the Commission in making its determination on Aurora Energy's CPP.

## 5.4 DRIVERS

### 5.4.1 Aurora Energy's proposal and our general observations

As part of our review of the identified opex programs, we identified the following key opex drivers that are not directly covered by the key assumptions noted above:

- after separation in July 2017, Aurora Energy has – with external advice – worked to establish an organisational structure that will support the asset management and system operations activities previously done by Delta, leading to a significant increase in the number of FTEs since 2017; the proposed increase in SONS relative to RY17 is \$12.3 million and \$12.0 million per year over the CPP and review periods respectively<sup>87</sup>
- in addition to SONS, the external review identified gaps in the organisational structure with regards to business support FTEs, which are necessary to support the regulatory, financial and enhanced

<sup>83</sup> RY18 cost data is used to determine a unit rate for the vegetation management forecast. RY19 opex is used to determine the base opex adopted in the base, step and trend forecasts for the maintenance programs.

<sup>84</sup> In some cases, Aurora Energy has suggested that such improvements may be offset by other factors. We have not seen sufficient evidence of such offset at this stage.

<sup>85</sup> The capex models forecast expenditure in real \$2020, before forecast inflation and real input cost escalation is applied. This escalation is applied separately in the CPP BBAR (i.e. financial model).

<sup>86</sup> Aurora Energy has applied top down efficiency adjustments across the opex portfolios that we have reviewed and has included some trended efficiencies in its maintenance forecasts to reflect improved asset condition. However, it is unclear to us whether some or all of these reflect either:

- efficiency improvements that an efficient EDB would have realised already if it were operating in Aurora Energy's circumstances – and so should be removed from base expenditure to set it at an efficient level
- on-going productivity improvements time relative to base expenditure that such an EDB should be able to realise over time.

The Commission should consider this further when undertaking its own review of the information provided.

<sup>87</sup> Although we are comparing the RY17 reported opex for SONS and people costs to that forecast for the CPP and review periods, we note that the cost structures and drivers differ across those years and so may not be directly comparable.

customer engagement activities – the proposed increase in people costs relative to RY17 is \$8.1 million and \$7.9 million per year over the CPP and review periods respectively<sup>87</sup>

- a change in maintenance strategy from reactive to more preventative approaches is needed to address safety and reliability risks on the network – the preventative and corrective maintenance forecasts include \$7.0 million and \$10.7 million for step changes above RY19 levels for the CPP and review periods respectively, excluding those for consumer poles.

## 5.4.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(1)(d) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

### Box 16 – IM requirements for opex drivers

#### Schedule G6(1)(d) of the IM:

The verifier must-

...

- (d) review, assess and report on any other **opex** drivers not covered by the **key assumptions** that have led to an increase in the **opex forecast** including whether the quantum of such an increase is required to meet the **expenditure objective**;

Our approach to assessment was to:

- identify other opex drivers not covered by the key assumptions that have led to an increase in the opex forecast
- review whether those drivers are appropriate, including by reference to our review of the selected opex projects or programs
- identify the impact of these drivers on the opex forecast and consider whether the increase is required to meet the expenditure objective.

## 5.4.3 Our findings

Our findings on the opex drivers are further discussed as part of our review of the selected opex projects and programs. In summary, in our view is that:

- the SONS and people costs incurred in RY19 and the FTEs that underpin them do not appear inefficient when compared with EDB peers in New Zealand and Australia, especially those that have more mature asset management practices
- if Aurora Energy continues towards gaining ISO55001 certification by RY23, then it will necessarily need to further introduce GEIP into the asset management and operations parts of its business, including by establishing an asset management system – these steps should allow Aurora Energy to better understand and plan for the condition of the asset fleet as it is discovered through the inspection programs
- the change in maintenance strategy is not unreasonable given the demonstrated need to deal with a rising volume of defects and risk profile
- a change in approach to vegetation management is not unreasonable.

## 5.5 REVIEW OF IDENTIFIED PROGRAMS

### 5.5.1 Aurora Energy’s proposal and our general observations

Aurora Energy proposes several opex programs covering a range of network and non-network activities. We selected six of these programs for detailed review and the outputs from this review are set out in Appendix C.<sup>88</sup> Our approach to selecting these programs is explained in Appendix B.

### 5.5.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(1)(g) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 17 – IM requirements for identified opex programs

##### Schedule G6(1)(g) of the IM:

The verifier must-

...

- (g) report conclusions of a detailed review of **identified programmes** that are **opex projects** or **opex programmes**, but is not limited to, an assessment of-
  - (i) whether relevant **policies** and **planning standards** were applied appropriately;
  - (ii) whether **policies** regarding the need for, and prioritisation of, the **project** or **programme** are reasonable and have been applied appropriately;
  - (iii) the process undertaken by the **CPP applicant** to determine the reasonableness and cost-effectiveness of the chosen solution, including the use of cost-benefit analyses to target efficient solutions;
  - (iv) the approach used to prioritise **opex projects** over time including the application of that approach for the **next period**;
  - (v) the **project operating cost** methodology and formulation, including unit rate sources, the method used to test the efficiency of unit rates and the level of contingencies included for **projects**;
  - (vi) the impact on other cost categories including the relationship with **capex**;
  - (vii) links with other **projects**;
  - (viii) cost control and delivery performance for **actual opex**;
  - (ix) the efficiency of the proposed approach to procurement; and

<sup>88</sup> Although not nominated as an identified program initially, we also reviewed the ICT opex program because it was bundled with the ICT capex program, which we did nominate.

(x) whether it should be included as a **contingent project** or part of a **contingent project**;

Our approach to assessment of the projects and programs was to:

- identify and review the documentation including models used to justify each of the key projects or programs and alignment with business policies and standards
- assess the information provided against common industry practice, appropriateness of forecasting methodologies, models and inputs
- undertake staff interviews to clarify any concerns and submit any questions through the SharePoint query process that was established
- where available, consider benchmarking with other EDBs
- consider any relationships between project and programs within the opex forecast and relationships with the capex forecasts and how these have been incorporated into the method or methods, or not
- review any methods used by Aurora Energy to check the reasonableness of its opex.

We reviewed the following identified operating projects and programs:

- maintenance
  - preventive maintenance including inspections
  - corrective maintenance
  - reactive maintenance
- vegetation management
- system operations and network support
- corporate services (business support)
- ICT opex (as part of our review of ICT capex).

### 5.5.3 Our conclusion

Our conclusions from this review are set out below, and detailed further in Appendix C. These conclusions inform our overall findings on capex, and our findings on other clauses within schedule G6 of the IM.

As summarised in Table 5.1, based on the information we have reviewed at this stage, we consider that the verified opex for the identified programs is \$136.8 million and \$220.0 million for the CPP and review periods respectively. For same periods, the unverified opex is \$5.0 million and \$9.2 million respectively.

**Table 5.1 – Verified opex from identified programs for the CPP / review period**

Opex program	Verified	Unverified
Preventative maintenance	\$19.0 million / \$30.5 million	\$0.0 million / \$0.0 million
Corrective maintenance	\$10.1 million / \$15.7 million	\$0.7 million / \$1.3 million
Reactive maintenance	\$13.3 million / \$21.6 million	\$0.5 million / \$1.1 million
Vegetation management	\$13.3 million / \$20.3 million	\$0.8 million / \$0.8 million

Opex program	Verified	Unverified
SONS	\$47.6 million / \$77.1 million	\$1.6 million / \$3.3 million
People costs	\$23.3 million / \$37.7 million	\$1.4 million / \$2.6 million
ICT opex	\$10.3 million / \$17.0 million	\$0.0 million / \$0.0 million
<b>Total</b>	<b>\$136.8 million / \$220.0 million</b>	<b>\$5.0 million / \$9.2 million</b>

### *Preventive, corrective and reactive maintenance*

In our view, Aurora Energy’s forecast corrective and reactive maintenance expenditure for the CPP and review periods appear too high and so does not fully meet the expenditure objective based on the information we have reviewed, while forecast preventative maintenance expenditure appears to fully meet the expenditure objective.

Our view is based on the following observations:

- the proposed change from a largely reactive to a more proactive maintenance approach is prudent and will likely result in lower whole of life costs – Aurora Energy has not yet modelled this, but has factored in some reduction to reactive maintenance expenditure
- the proposed asset maintenance strategies and initiatives for preventative, corrective and reactive maintenance are generally in line with GEIP – and so the need for most of the proposed step changes appears reasonable
- RY19 base year expenditure appears high when total maintenance opex is compared to similar expenditure incurred by other New Zealand EDBs, although this is not statistically significant
- an improved contracting approach (with three service providers) and moving to a more structured and better approach to maintenance should lead to efficiency improvements to total maintenance expenditure over the CPP and review periods – such improvements are likely, to some degree, be captured into the maintenance costs of comparator EDBs used in the benchmarking analysis considered in section C.17
- based on the information available, some step changes could not be justified against the expenditure objective
- the proposed increases in corrective and reactive maintenance to reflect scale growth over the CPP and review periods does not appear appropriate given that activities in these programs are largely driven by the volume of defects and faults
- appropriate modelling has been undertaken to determine forecast expenditures, including using the network scale assumptions adopted by the Commission for the DPP.

We consider that the maintenance expenditure verified is \$42.4 million over the CPP period and \$67.9 over the review period. The unverified expenditure is \$1.3 million and \$2.5 million respectively. Table 5.2 breaks these values down by program.

**Table 5.2 – Verified maintenance expenditure for the CPP / review period**

Opex program	Verified	Unverified
Preventative	\$19.0 million / \$30.5 million	\$0.0 million / \$0.0 million
Corrective	\$10.1 million / \$15.7 million	\$0.7 million / \$1.3 million

Opex program	Verified	Unverified
Reactive	\$13.3 million / \$21.6 million	\$0.5 million / \$1.1 million
<b>Total</b>	<b>\$42.4 million / \$67.9 million</b>	<b>\$1.3 million / \$2.5 million</b>

### *Vegetation management*

In our view, Aurora Energy’s forecast vegetation management for the CPP and review periods appears too high and does not meet the expenditure objective based on the information we have reviewed.

Our view is based on the following observations:

- transitioning to a five-year cutting cycle is consistent with GEIP and is appropriate to meet the regulatory requirements
- the proposed unit rate for undertaking the work – of \$98,907 – is based on RY18 expenditure that appears inefficient, indicating that the unit rate is also
- apart from the unit rate, appropriate modelling has been undertaken to determine the forecast expenditure
- projected efficiency improvements should be realised from the start of the CPP period as the new approach will be implemented during 2019-20.

Given the top-down efficiency improvements proposed by Aurora Energy and our benchmarking of Aurora Energy’s vegetation costs against New Zealand and Australian industry peers, we consider that – as a minimum – the projected efficiency gain of 8.5% in RY26 should apply from RY22. Doing so gives verified vegetation management expenditure of \$13.3 million for the CPP period and \$20.4 million for the review period. The unverified component of the forecasts is \$0.8 and \$0.8 million respectively.

### *System operations and network support*

In our view, Aurora Energy’s base SONS expenditure does not appear inconsistent with the expenditure objective based on the information reviewed, except for applying a network scale trend and the proposed insurance step change.

Our view is based on the following observations:

- given the significant step up in recruitment required, Aurora Energy’s board and senior management appeared to have applied significant top-down challenge to ensure that the new roles are appropriate and meet an immediate need in improvement asset management capability
- the reality that Aurora Energy had to fund the step up in expenditure over RY19 and RY20 without any expected regulatory revenues to cover this – which aligns with the apparent level of challenge applied by the board and senior management
- comparison to other EDBs suggests that RY19 SONS expenditure is not inefficient
- the projected real increases in insurance premia do not recognise the significant impact that the COVID-19 pandemic is and is likely to have on global and domestic insurance markets
- although the size of the network may drive SONS expenditure in the future, this is unlikely to be the case over the CPP and review periods where the key driver of that spend is ramping up Aurora Energy’s asset management capability to support delivery of significant renewal, maintenance and other programs – which largely factors in network growth already.

After removing the scale trend and proposed insurance step change reduces forecast SONS expenditure, we consider that the SONS expenditure verified is \$47.6 million and \$77.1 million over the CPP and

review periods respectively. The unverified component of the forecasts is \$1.6 and \$3.3 million respectively.

### *People costs*

In our view, Aurora Energy's base people costs forecast does not appear inconsistent with the expenditure objective based on the information reviewed, except for applying a network scale trend.

For similar reasons to the SONS program discussed above, our view is based on the following observations:

- establishing its own in-house business support capability is consistent with the Deloitte recommendations and GEIP – such capability helps ensure that Aurora Energy can deliver safe, reliable and affordable electricity to its consumers
- given the significant step up in recruitment required, Aurora Energy's board and senior management appeared to have applied significant top-down challenge to ensure that the new roles are appropriate and meet an immediate need in improvement asset management capability<sup>89</sup>
- all step changes appear appropriate – however, we could not verify the proposed *level* of increase in staff training costs (\$0.7 million over the CPP period and \$1.2 million over the review period) due to insufficient information<sup>90</sup>
- the reality that Aurora Energy had to fund the step up in expenditure over RY19 and RY20 without any expected regulatory revenues to cover this – which aligns with the apparent level of challenge applied by the board and senior management
- comparison to other EDBs suggests that RY19 people costs is not inefficient
- although the size of the network may drive people costs indirectly in the future, this is unlikely to be the case over the CPP and review periods where the key driver of that spend is ramping up Aurora Energy's business support capability to indirectly support delivery of significant renewal, maintenance and other programs – which largely factors in network growth already.

We consider that the people costs verified are \$23.3 million for the CPP period and \$37.7 million for the review period. The unverified component of the forecasts is \$1.4 million and \$2.6 million respectively.

### *ICT opex*

We have reviewed the planned changes from developing and maintaining bespoke programs and supporting applications, to a cloud-based set of standard applications to support business support activities – which is consistent with GEIP and the practices of other New Zealand EDBs.

In our view, Aurora Energy's forecast ICT opex for the CPP and review periods does not appear inconsistent with the expenditure objective based on the information that we have reviewed.

Our view is based on the following observations:

- there is an apparent need to address inherent risks associated with:
  - Aurora Energy's existing asset management and business support applications – and the complex interactions between them

---

<sup>89</sup> For instance, the information provided indicate that the challenge process led to several positions identified by managers being deferred to a later time and ensured that those that were approved had been closely examined to ensure that they were prudent and efficient.

<sup>90</sup> To be clear, although we have treated the training cost step change as unverified, it may nevertheless satisfy the expenditure objective. Based on the information available, we were unable to conclude that it did.

- the serious data integrity issues that are compromising efficient management and operation of its network
- moving from in-house software solutions to cloud-based solutions – as Aurora Energy is proposing – is consistent with GEIP and increasingly becoming a necessity in today’s ICT solutions marketplace to ensure that support is provided indefinitely and 24/7
- the proposed ICT initiatives and cost estimates are based on:
  - findings from external reviews that have identified key issues and recommended solutions that appear consistent with GEIP, including by clearly articulating and focusing on business needs
  - feedback from consumers and the CAP on the need to improve the timeliness and proactivity of communication with customers around works that affect them
- the forecasting method appears appropriate, with the bottom-up estimating approach providing the best opportunity for work to fully scheduled ICT initiatives through phased implementations, as well as allowing for prioritising the most critical ICT requirements to improve network assets management
- the four-stage approach used to generate and moderating the forecasts appears robust and rigorous – and, in our view, ensures that the business and consumer needs are fairly captured and analysed against the current needs as detailed by ISSP 2025 and prioritised
- although only added to the forecasts after our draft report, ICT costs that were missed initially (totalling \$4.0 million and \$6.3 million over the CPP and review periods respectively) appear reasonable<sup>91</sup>
- forecast recurrent ICT expenditure (including the missed costs) appears consistent with Australian EDBs.<sup>92</sup>

We consider that the ICT opex verified is \$10.3 million for the CPP period and \$17.0 million for the review period.

## Summary

Figure 5.2 and Figure 5.3 illustrate the verification summary for the identified opex programs for the CPP and review period respectively.

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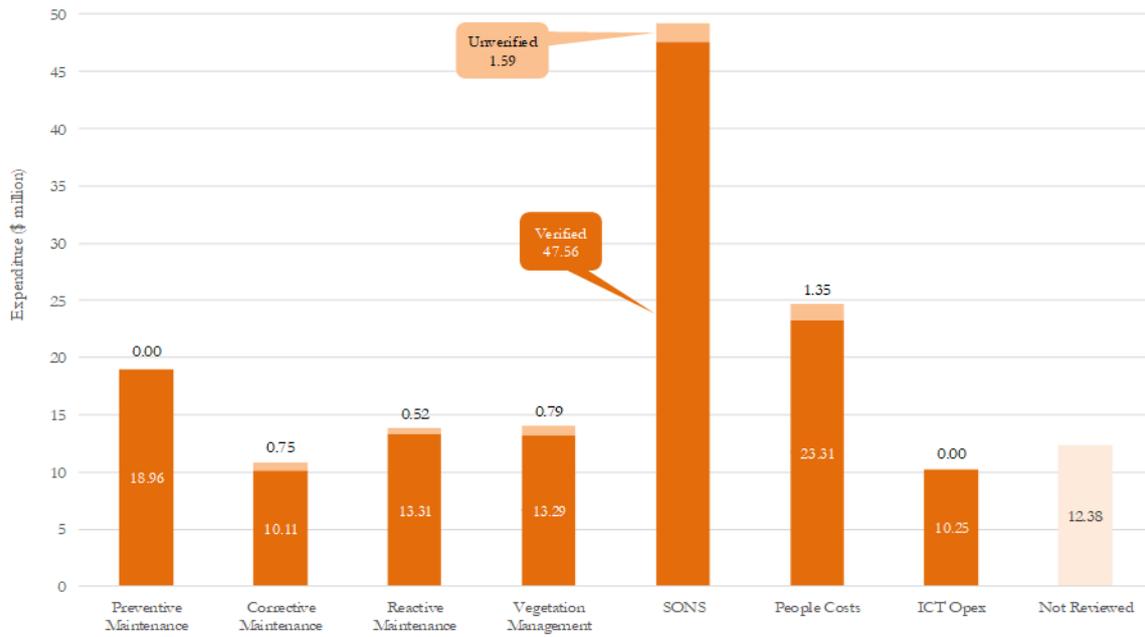
<sup>91</sup> After providing our draft report, Aurora Energy identified that it had inadvertently missed some recurrent ICT costs from its expenditure. Although we did not consider these costs in our draft report, we did when preparing this report.

The omitted costs relate to:

- Corporate services in the cloud: \$1.6 million / \$2.6 million
- GIS services: \$0.6 million CPP / \$1.0 million Review period
- Data/network protection and security - \$0.6 million / \$0.8 million
- Asset inspection: \$0.2 million / \$0.4 million
- Infrastructure protection systems (“Before You Dig”) - \$0.2 million / \$0.4 million
- Video conferencing: \$0.1 million / \$0.1 million
- Other enterprise applications: \$0.7 million / \$1.0 million.

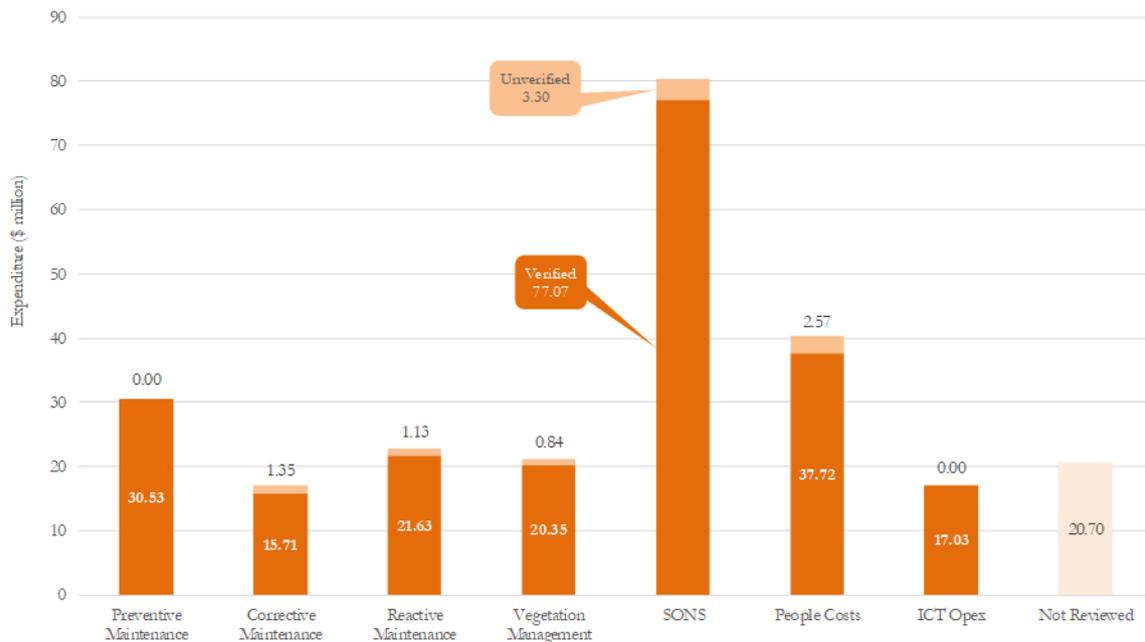
<sup>92</sup> We benchmarked Aurora Energy’s forecast recurrent ICT expenditure against that of Australian EDBs because there was insufficient data available for New Zealand EDBs.

Figure 5.2 – Verified opex over the CPP period (\$2020, \$million)



Source: farrierswier and GHD analysis.

Figure 5.3 – Verified opex over the review period (\$2020, \$million)



Source: farrierswier and GHD analysis.

## 5.6 REDUCTION INITIATIVES

### 5.6.1 Aurora Energy’s proposal and our general observations

Aurora Energy does not appear to be proposing any specific opex reduction initiatives or to have reflected in its opex forecasts the outcomes from such initiatives undertaken during the current period, except to the extent that they are reflected in the base expenditure used to forecast opex.<sup>93</sup>

However, Aurora Energy has recognised in its forecasts that some proposed renewal expenditure may lead to reductions over the CPP and review periods and has included top-down efficiency adjustments across all of the opex programs that we reviewed.

### 5.6.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(1)(f) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

#### Box 18 – IM requirements for opex reduction initiatives

##### Schedule G6(1)(f) of the IM:

The **verifier** must:

...

- (f) provide an opinion as to the reasonableness of any **opex** reduction initiatives undertaken or planned during the **current period** or the **next period**;

Our approach to assessment was to:

- identify any opex reduction initiatives undertaken or planned during the current period or the CPP period
- review these for reasonableness against what we would expect for a prudent non-exempt EDB.

### 5.6.3 Our findings

Based on our assessment of the documents and models provided, we are not aware of any specific opex reduction initiatives undertaken or planned during the current period or the proposed CPP and review periods. We were, therefore, unable to provide a view.

However, as noted above, we would expect some of the opex and capex initiatives proposed by Aurora Energy for the CPP and review periods to result in opex reductions over that period – and Aurora Energy has recognised this by applying top-down efficiency adjustments and in specific opex programs, e.g. efficiency reductions to reactive and corrective maintenance from proposed renewal expenditure reducing faults. Our view is that the proposed adjustments are modest in relation to benefits that could be reasonably expected from changes in the contracting model, improved asset management planning, and processes that should come from the planned ICT expenditure. Limited justification for the proposed adjustments made it hard for us to validate whether they are reasonable. Based on the information available, we were unable to provide a view as to exactly what reductions are possible.

<sup>93</sup> We interpret the term ‘opex reduction initiative’ to be an initiative solely targeted at reducing opex.

## 5.7 DELIVERABILITY

### 5.7.1 Aurora Energy's proposal and our general observations

As noted in relation to capex deliverability (section 4.5), Aurora Energy's field resource capability is delivered entirely by external contractors with no field staff employed by Aurora Energy. Most of this capability is expected to be delivered by three contractors under separate FSAs (Delta, Connetics and Unison), with additional approved contractor resources available for tender or other work. We discuss this further in section 6.5.1.

Aurora Energy has recognised that the forecast increase in expenditure during the CPP and review periods requires a delivery strategy that works closely with service providers to ensure that they have capability to deliver the volume of field services work required. Aurora Energy has sought commitments in principle from those providers to support its planned works, including to:

- ensure that services are delivered in a timely, efficient and cost-effective manner in accordance with the standards and quality requirements contained in the FSAs
- continuously explore opportunities to improve delivery of the services
- explore initiatives and innovations that enhance efficiencies, reduce costs and promote sustainability
- ensure that the parties prioritise health and safety and take all reasonably practical steps to achieve zero harm to people, property and the environment.

Under the FSAs, Aurora Energy's preventive and corrective maintenance has been split as:

- Dunedin network area – Unison and Delta
- Central Otago network area – Connetics and Delta.

Delta is also the preferred contractor for vegetation management and faults.

Aurora Energy has also established a panel of other approved contractors that can support delivery of work if the FSA service providers are unable to or if that work is tendered. Although Aurora Energy has considered resourcing requirements at a higher level, it does not appear to have in detail, such as by mapping resource requirements to regions, considering depot locations and recruitment lag times.

Finally, Aurora Energy recognises that an uplift in internal resourcing was needed to both develop its own asset management and business support capability and to support the increased work volume planned to be delivered by external contractors. Most of the roles identified as needed for the SONS and people costs programs have either already been filled or are close to it with little increase forecast beyond RY20.

### 5.7.2 IM requirements and our approach to assessment

This section aims to address Schedule G6(1)(h) of the IM, and our approach to assessing compliance of Aurora Energy's CPP against the IM requirements.

### Box 19 – IM requirements for opex deliverability

#### Schedule G6(1)(h) of the IM:

The verifier must-

...

- (h) provide an opinion as to overall **deliverability** of work covered by the **opex categories** in the **next period**;

Similar to that described in section 4.5.3, our assessment examined Aurora Energy’s preparation at an aggregate program level for its proposed expenditure delivery. For instance, we reviewed the scheduled program of preventive and corrective work for all three contractors for RY21 to understand the work volumes that are being allocated to each.

We reviewed the existing FSA set-up for competitive tension provision, arrangements for performance feedback, visible pipeline of proposed work within the ACE limit for each FSA contractor and outside the limit (i.e. open tender work) for sustainability, metrics for KPI measurements, and the FSA contractors’ commitment in maintaining a sufficient level of resources to deliver the work.

We also considered the nature of resources, tools, system and data required within Aurora Energy to effectively plan, manage, contract and administer and the proposed volume of network maintenance work. This involved us understanding the features of Aurora Energy’s new project management tool Sentient PPM, the system operations and network support functionalities, accredited project management training and capacity, and reviewing position descriptions of various crucial existing roles and planned recruitments.

### 5.7.3 Our findings

#### *Deliverability of the opex forecast*

In our view, the work proposed in the opex forecasts over the CPP and review periods does not appear undeliverable, with some limitations.

Although on-the-ground systems, processes and resources are all being established and new contractual arrangements implemented, there are risks around management bandwidth and the challenging timeframe assumed in the forecasts to mobilise projects and programs given the significant step up in proposed activity in some areas and the wide-range of initiatives. This is even more so given that the COVID-19 pandemic is likely to undermine delivery during RY21 and potentially for longer.

We note that delivery risks could result from:

1. system and process changes creating challenges for internal resources – Aurora Energy is most of the way through a planned significant increase in internal resources for some expenditure categories and based on our experience, establishing new teams on such a large scale while implementing new systems and process can lead to some lost productivity, albeit this is often temporary
2. events like the COVID-19 pandemic affecting ability to undertake non-essential work – given the current restrictions in place, it is likely that delivery of work in RY21 will be compromised to some degree; if these restrictions or other implications from the pandemic persist (e.g. ability to source labour or equipment), then the work program forecast for the CPP and review periods may also be compromised

3. Aurora Energy potentially awaiting the Commission's final determination before ramping up some activities in full – this may affect the timing of such activities, especially if they have long lead times, although we understand that Aurora Energy currently intends to ramp up for its planned investments.

However, Aurora Energy can manage the above risks and therefore we consider that Aurora Energy will be able to deliver its operating work program based on the information that we have seen.

### *Deliverability strategy and implementation*

Similar to our findings in section 4.5, Aurora Energy has analysed its internal skill and resource gaps and has actively started addressing the identified gaps.

The progress made so far in implementing the project management systems, training and building the capability and capacity of the relevant asset management and operations teams. A contractor performance manager administers the FSA contracts, monitoring the performance and implementing the feedback to determine contract terms and work volumes. Although these steps are reasonable, there always remains some delivery risk when both establishing new internal capability and using new contractual arrangements to deliver a significant step up in activity.

For all three contractors, access to ACE – which represents approximately 50 per cent of Aurora Energy's annual maintenance spend – is subject to their satisfying the various contract KPIs. This will create market pressure for the contractors to perform and drive for cost efficiencies where possible.

The current price book used by Aurora Energy is based on building block unit rates sourced, in part, from historical costs that have not been market tested but have been reviewed for reasonableness by Jacobs (refer section 6.5). Aurora Energy advised that an interim service agreement in 2019 included a reduced margin on the cost of opex work on Delta. Consistent with this, we would expect that the contractual mechanisms that Aurora Energy has been put in place should push all three contractors covered by the FSAs to deliver cost efficiencies against these historical costs.

Vegetation management has been awarded solely to Delta for a two-year period to RY21 and its performance is being closely monitored and assessed against Aurora Energy's new vegetation management standard for compliance with the type of cutting and the drive towards a five-year cycle for recutting, instead of the previous 12–18 month cycle. Delta's retaining of the work beyond RY21 will be dependent upon its performance during the two-year contract. In our view, this is both an appropriate and necessary push for efficiency in the vegetation management program, as historical efforts have been characterised as being inefficient for the length of affected line cut (refer section C.20).

Aurora Energy has not analysed potential constraints due to external market factors in its region competing for similar resources. However, based on discussion with Aurora Energy's executive, we are reasonably satisfied that it has taken steps to ensure that these risks can be managed effectively. Aurora Energy's FSA contractual set-up and the additional contractors for the open tender participation appear to provide Aurora Energy with sufficient flexibility when outsourcing work.

Aurora Energy advised that the CPP projected forecasts have been shared with the key service providers through their respective FSA governance meetings and has received informal responses indicating that there is sufficient available internal and subcontract staff available. In our view, the contractors should provide a formal response, detailing their resource capability for the next RY, and any strategies they have in place to mitigate any resourcing risks.

## 5.8 MODELS AND FORECASTING METHODS

### 5.8.1 Aurora Energy's proposal and our general observations

Aurora Energy has used two methods for generating the opex forecasts:

- **For the maintenance, SONS and people cost programs (and non-identified opex programs)** – a base, step and trend approach which is applied where the category spend is based on annual business-as-usual activities. This approach is used by the AER and the Commission and is considered a robust method for categories with a relatively consistent spend pattern.
- **For vegetation management and ICT opex** – a volumetric estimating approach where work volumes are forecast and multiplied by the unit rates for the activities or tailored forecast (e.g. insurance premium quotes).

Aurora Energy gives effect to these methods using separate models for each program. In some cases, it also has separate spreadsheets that calculate the proposed step changes.

These models generate expenditure forecasts in real \$2020, before forecast inflation and real input cost escalation is applied. This escalation is applied separately in the CPP BBAR (i.e. financial model). We consider cost escalation further in section 6.4.

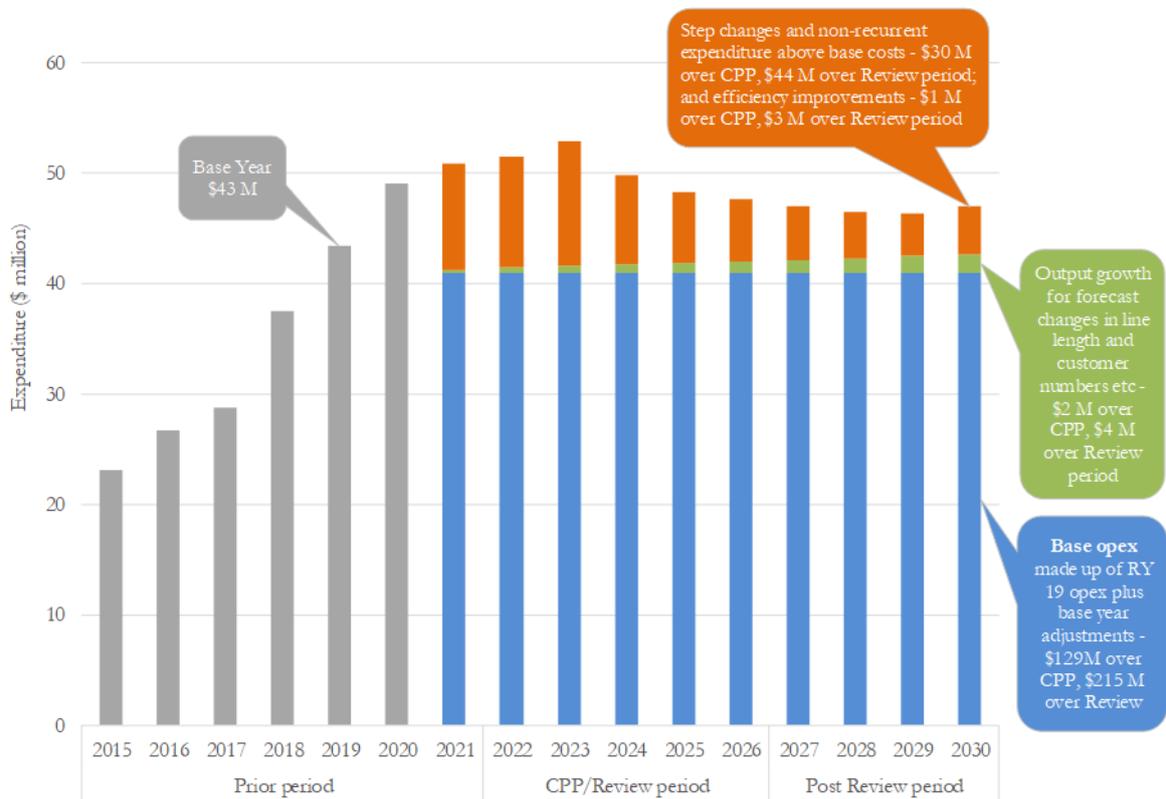
#### *Base, step and trend method*

Aurora Energy applies the base, step and trend method in the following way:

- **Determine base year** – a common base year (in this instance, RY19) is used for all programs forecast using the method.
- **Remove non-recurrent expenditure** – base year expenditure was assessed to determine if it has only recurring costs, and adjusted where non-recurring costs are identified or there was a need to transfer some costs from one program to another (with a net effect of zero), such as:
  - a reduction in preventive maintenance base year cost of \$182,000 for non-recurring costs
  - for SONS – removal of \$148,059 for two property rental costs that are included in the people costs forecast, a correction of \$118,632 for other rental costs that had been transferred twice in error, and various other adjustments that combined reduce base expenditure by \$1.5 million
  - for people costs – removal of \$1.8 million in one-off consultancy costs plus addition of payroll costs and transfers from the SONS portfolio summing to \$1.1 million, giving a net reduction of \$0.7 million.
- **Add or remove step changes** – forecast step changes and non-recurrent expenditure were added to reflect specific initiatives or expected increases in work volumes during the CPP and review periods, including proposed expenditure on preparing a five-year CPP to start in RY25. A negative step change was included for reactive maintenance, after internal moderation, to reflect improved reactive maintenance practices.
- **Apply trend** – the adjusted base year expenditure was trended forward for network growth using the forecasts reflected in the DPP for the RY21 to RY25 period. Negative trends were also included for corrective and reactive maintenance to recognise that the renewal programs will likely improve asset condition and lead to fewer faults.
- **Apply efficiency improvement** – top-down percentage reductions were applied to the forecast expenditure, to consider anticipated improvements in asset management and planning systems, processes and resources, and cost efficiencies through the new FSAs.

Figure 5.4 shows the consolidated base, step and trend forecast for all categories of opex (excluding cost escalation). For presentation purposes, this figure also includes the expenditure for vegetation management, ICT opex and non-identified programs – with the increase in opex above that in RY19 included in the ‘step changes and non-recurrent expenditure’ bar (in orange).

**Figure 5.4 – Consolidated base, step and trend opex forecast, including efficiency improvements (\$2020, \$million)**



Source: Aurora Energy opex forecast models for the data, analysed and re-cut by farrierswier and GHD.

As shown, RY19 base year expenditure is significantly higher than that for prior years. The step-up in opex since the separation in July 2017 is particularly obvious – most of which corresponds to:

- significant increases in SONS and people costs as Aurora Energy was set up as a separate entity and developed an organisational structure in line with recommendations of an external review to more adequately address the needs for asset management (and certification for ISO55001 by RY23) and business support functions
- increased inspection and testing work to support the fast track pole replacement program from RY17 to RY19
- an increase in reactive maintenance in RY17 to address network outages during extreme weather events
- increased vegetation management activity to address a backlog of work, including through the catch up needed to transition to a five-year cutting cycle.

By RY19, a significant amount of the internal restructuring of SONS, and business support functions was completed and so the proposed step from there is much lower.

### *Step change alignment to strategy*

In response to the key findings of the WSP review of the state of the network, from RY19 Aurora Energy has increased preventive and corrective maintenance activity to address the backlog of routine maintenance and general poor condition of network assets. These are included in the step changes shown in Figure 5.4.

As well as the step up in staffing as part of its separation from Delta, other key driver for the SONS and people costs step changes for the CPP and review periods are:

- additional health and safety audits
- initiatives in preparing for the network to evolve in response to increase penetration of PVs, electric vehicles and battery storage
- application costs for the second CPP application for the period starting RY25.

### *Other forecasting methods*

Of the programs we reviewed, vegetation management and ICT opex were forecast using methods other than the base, step and trend as follows:

- **Vegetation management** – forecast expenditure was calculated using a volume times unit rate approach. After an initial catch up cut cycle, volumes are expected to reduce to a steady state five-yearly cutting cycle, consistent with Aurora Energy’s vegetation management strategy and standard.
- **ICT opex** – consistent with forecast ICT capex, a bottom up build of the costs of solutions was used to forecast ICT opex. The move from licences to cloud (i.e. software as a service) based solutions drives a shift from capex to opex. Bottom up costs were based on external input, vendor quotes, benchmarking, and internal judgement.

### *Forecast validation*

Aurora Energy has undertaken internal reviews of its proposed opex forecasts, and there is evidence of internal moderation decreasing some forecasts (e.g. some proposed roles removed from the SONS and people costs forecasts, and negative trends included in the corrective and reactive maintenance forecasts).<sup>94</sup>

Aurora Energy also provided us with benchmarking of its current and proposed expenditure against other New Zealand EDBs, which generally shows it is comparable with its peers.<sup>95</sup> We consider benchmarking further in the program reviews in Appendix C and in Appendix G.

## **5.8.2 IM requirements and our approach to assessment**

This section aims to address Schedule G6(1)(e) and (i) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

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<sup>94</sup> See, for instance: Aurora Energy, *CPP Update – Proposed Submission Forecasts*, 4 May 2020.

<sup>95</sup> Aurora Energy, *Industry benchmarking - Maintenance Opex* received in response to IR questions, 29 Mar 2020.

## Box 20 – IM requirements for opex forecasting methods and models

### Schedule G6(1)(e) and (i) of the IM:

The verifier must-

...

- (e) provide an opinion as to the reasonableness of the methodology used in forecasting **opex** (such as cost benchmarking or internal historical cost trending), including the relationship between the **opex forecast** and **capex forecast**;

...

- (i) provide an opinion as to the reasonableness and adequacy of any **opex** models used to prepare the **opex forecast** including an assessment of-
  - (i) the inputs used within the model; and
  - (ii) any methods the **CPP applicant** used to check the reasonableness of the forecasts and related expenditure.

Our approach to assessment was to:

- identify the forecast method or methods used by Aurora Energy to develop its opex forecasts
- review the method or methods against GEIP and those likely to promote the expenditure objective
- consider any relationships between the opex and capex forecasts and how these have been incorporated into the method or methods, or not
- review the models and inputs used to apply the method or methods
- review any methods used by Aurora Energy to check the reasonableness of its opex forecasts.

### 5.8.3 Our findings

Overall, Aurora Energy has generated the opex forecasts based on the historical expenditure data available and reasonably considered the expected requirements for the CPP and review periods. In doing so, Aurora Energy has used forecasting methods and models that are consistent with GEIP for regulatory proposals, and to the best of its ability, reviewed the forecasts to check that they are reasonable and deliverable.

#### *Forecasting method*

In our view, nothing has come to our attention that causes us to believe that, in all material respects, Aurora Energy’s overall methodology for forecast opex is not unreasonable.

Our view is based on:

- the base, step and trend method being a well-accepted method for forecasting recurrent opex and is commonly used in rate setting processes like the CPP process
- using a volume or quantity driven forecast for vegetation management is not unreasonable, especially where a significant step change in volumes is forecast (e.g. the catch up cuts)
- the forecasting model used for vegetation management aligns to the strategy proposed by Aurora Energy, including the modelling of catch up first cut spend and the impact of second cuts

- the output growth applied to the maintenance opex forecasts appears consistent with the percentage increase in the Commission's DPP decision
- the opex forecast is adjusted in some cases to reflect interdependencies with the capex forecast, or with other initiatives, for instance:
  - corrective and reactive maintenance is adjusted downwards to reflect expected improvements in asset condition from the proposed renewal programs
  - corrective maintenance was also adjusted upwards to reflect an expected increase in defects needing corrective action following the step up in preventative maintenance activities
  - reactive maintenance was adjusted downwards to reflect expected improvements from the way that reactive maintenance is delivered via its service provider, Delta.

We do, however, have concerns with how the forecasting methods were applied to some programs and have not seen sufficient information to verify key inputs (e.g. vegetation management unit rate and two step changes). We discuss these concerns and inputs further in section 5.5.3 and in more detail in Appendix C.

We also note that, although Aurora Energy uses the base, step and trend method, its application of it differs in some respects from how it is applied by the AER and the Commission. For instance, Aurora Energy:

- although it removed some non-recurring spend, it did not initially assess base year expenditure for efficiency before adopting them, rather it generally just compared that expenditure to prior years – when applying the method, the AER and other regulators assess base expenditure for efficiency and in some cases reduce it to what is considered efficient
- did not apply a single base, step and trend across all opex categories using this approach – as the AER would generally do – or for network and non-network categories – as the Commission did in its DPP determination for network and non-network expenditure – but instead applies the method separately to each expenditure program<sup>96</sup>
- although top-down efficiency adjustments were applied, they were not included as part of the trend component and were not applied as year on year productivity improvements.<sup>97</sup>

### *Forecasting model*

In our view, the models used by Aurora Energy to develop its opex forecast are not unreasonable and do not appear inadequate for that purpose as they appear to give effect to the intended forecasting methods.

Our view is based on these findings:

- the models appear robust (noting that we have not undertaken a model audit)<sup>98</sup> and consistent with methods described
- the assumptions and inputs used within the models appear consistent with the proposed strategies as described in the information provided to us.

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<sup>96</sup> We note, however, that applying the base, step and trend method to individual expenditure programs is consistent with recent proposals for Transpower and Powerco.

<sup>97</sup> As well as the top-down efficiency adjustments, Aurora Energy included reductions to the reactive and corrective maintenance forecasts linked to improved asset condition.

<sup>98</sup> We understand that Aurora Energy has engaged Audit New Zealand to audit / review the models and spreadsheets underpinning its expenditure forecasts. We are not aware of any outstanding audit issues.

We note, however, that:

- not all inputs used in the models were fully described in the information provided to us, including as to their source – these are detailed in the program reviews in Appendix C
- Aurora Energy appears to have used its best effort to identify historical spending across the network maintenance categories, with data prior to July 2017 being in poor condition and typically paper-based – where this data was not sufficiently detailed, Aurora Energy appears to have been conservative (i.e. leading to lower expenditure) with regards to any assumptions or conclusions that were based on it.

## 6. Other matters

In this chapter, we assess other matters required by schedule G of the IM that are not covered by our review of Aurora Energy’s forecast expenditure and service levels, measures and quality standard variations.

This chapter is structured as follows:

Heading	Sets out
Section 6.1	Findings on Aurora Energy’s forecast capital contributions
Section 6.2	Findings on Aurora Energy’s forecast demand
Section 6.3	Findings on Aurora Energy’s proposed contingent projects, if any
Section 6.4	Findings on Aurora Energy’s forecast cost escalation
Section 6.5	Findings on Aurora Energy’s cost estimation
Section 6.6	Findings on Aurora Energy’s network risk
Section 6.7	Findings on Aurora Energy’s procurement practices
Section 6.8	Observations about how Aurora Energy’s expenditure and deliverables could be tracked

### 6.1 CAPITAL CONTRIBUTIONS

#### 6.1.1 Aurora Energy’s proposal and our general observations

Aurora Energy is proposing \$20.5 million of forecast capital contributions over the CPP period and \$39.6 million over the review period, covering contributions to both consumer connections and asset relocations.

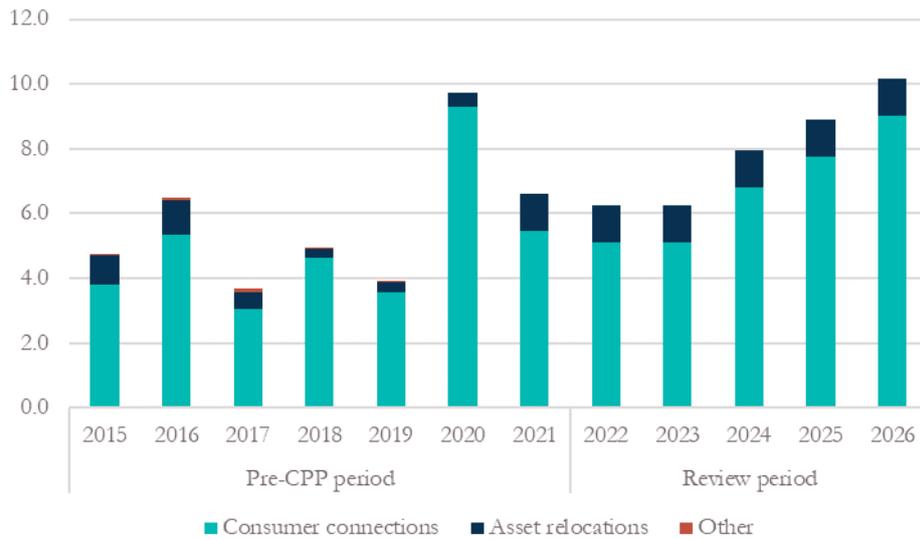
This compares to \$23.7 million over the RY15 to RY19 period, which included contributions to consumer connections (86%) and asset relocations (13%) as well as smaller contributions to system growth (0.3%), asset replacement and renewal (0.4%), quality of supply and other reliability (0.1%), and safety and environment (0.2%).<sup>99</sup>

Forecast capital contributions were calculated by multiplying forecast gross consumer connection and asset relocation expenditure by 60%. Aurora Energy did not distinguish between types of connections or relocations and adopted this assumption based on a targeted level of contributions rather than its current connection policy.

Figure 6.1 compares historical contributions to forecast in dollar terms, while Figure 6.2 compares the contribution rates for consumer connections and asset relocations. As shown, both the dollar value and contribution rate are forecast to increase significantly over the review period. The slight reduction from RY21 to RY22 and RY23 reflects the potential impact of the COVID-19 pandemic.

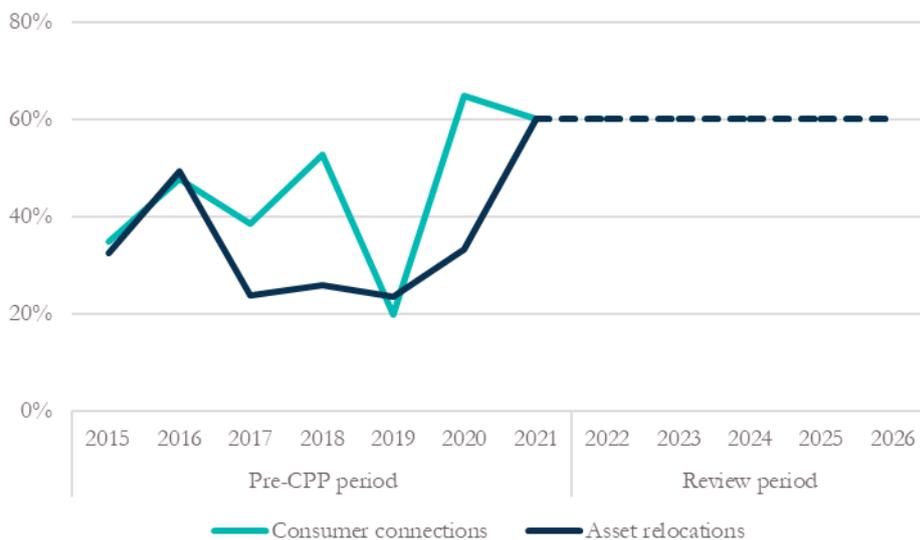
<sup>99</sup> Aurora Energy advised that the historical capital contributions reported against categories other than consumer connection and asset relocation were for projects carried out on a conjoint basis where the primary driver was not consumer connection nor asset relocation. Aurora Energy advises that it no longer uses that approach for reporting contributions and so is only forecasting contributions associated with consumer connections and asset relocations.

Figure 6.1 – Capital contributions (\$2020, \$million)



Source: Aurora Energy data. Forecast expenditure does not include cost escalation.

Figure 6.2 – Contribution rate



Source: Aurora Energy data. Farrierswier and GHD analysis.

### 6.1.2 IM requirements and our approach to assessment

This section aims to address Schedule G7 of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

## Box 21 – IM requirements for capital contributions

Schedule G7 of the IM:

The verifier must provide an opinion as to whether the forecast of capital contributions–

- (a) is reasonable; and
- (b) consistent with other aspects of the CPP proposal, in particular–
  - (i) the capex forecast; and
  - (ii) forecast demand data provided in accordance with clause D6.

Our approach to assessment was:

- review the model, inputs and assumptions used to forecast capital contributions
- compare forecast capital contributions for the CPP period to forecast asset relocation and customer connection capex for the same period
- compare the proposed rate of contribution to that observed historically
- review any explanation or justification for the proposed capital contribution forecast, including on proposed changes to Aurora Energy’s connection policy.

The documents and models that we reviewed are set out in Table 6.1.

Table 6.1 – Information provided – capital contributions

Title	Reference	Date
POD50 - Consumer Connection	E-25	27 February 2020
MOD50 - Consumer Connection Forecast Model	E-26	27 February 2020 (updated 7 May 2020)
P13 - Other Network Capex - Consumer Connection	V-112	26 March 2020
<b>Provided in response to our draft report</b>		
Note regarding MOD50 – Consumer Connection Forecast Model	PR-7	22 April 2020

### 6.1.3 Our findings

In our view, the capital contributions forecast does not appear materially unreasonable nor materially inconsistent with other aspects of the CPP proposal, subject to the limitations noted below.

Our view is based on the following observations:

- using a fixed contribution rate for consumer connections and asset relocations means that there is a direct link – or consistency – between the expenditure and capital contribution forecasts
- although the fixed contribution rate was based on a target adopted by Aurora Energy rather than recent experience, that rate is higher than that observed recently and so – if anything – may overestimate contributions and therefore underestimate net connection and asset relocation expenditure, reducing the impact on consumer prices

- forecast connection expenditure incorporates a likely reduction in connections that will result from the impact of COVID-19 on tourism and the economy more generally<sup>100</sup>
- although historically some contributions were attributed to expenditure categories other than consumer connections and asset relocations, these values were small (<1%) and are not expected by Aurora Energy to continue in the future
- assuming no change to recent asset relocation expenditure in real terms (before capitalisation of internal costs) is not unreasonable in the circumstances where no other information is available about the likely need for relocations over the CPP and review periods.<sup>101</sup>

Although there are several limitations with the proposed forecast, we do not consider that these materially affect our view above. These limitations include:

- because forecast consumer connection and asset relocation expenditure was not linked to forecast ICP or household growth (e.g. as reflected in the opex growth trend or used when developing some demand forecasts) or economic activity, the contribution forecast also does not link to those drivers, which creates a potential inconsistency with other components of the CPP proposal
- the target contribution rate for connection expenditure (60%) adopted by Aurora Energy is based on an expectation that changes to its connection policy will increase the rate from current levels without – at the time of writing – having identified those changes, what resistance there may be to adopting them (e.g. from developers and other stakeholders), nor what impact they would likely have on contribution rates
- contributions were forecast in aggregate rather than by connection type, which therefore assumes away differences in contribution rates between those types, which is unlikely to reflect reality
- forecast connection expenditure does not factor in a potential reduction in connections that may result from increasing contributions rates (e.g. if parties looking to connect to Aurora Energy’s network defer or reconsider connecting due to the higher contribution requirements) and so forecast contributions are likely overstated as a result.<sup>102</sup>

#### 6.1.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast capital contributions was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

For the reasons noted above, although we do not consider forecast capital contributions are materially unreasonable in the circumstances, the Commission may want to consider when undertaking its own assessment of the information:

- the potential impact of the COVID-19 pandemic on tourism and the economy that may affect forecast connection expenditure and therefore capital contributions

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<sup>100</sup> As we have not reviewed the asset relocations expenditure forecast directly, it is not clear whether such an impact has been factored into it.

<sup>101</sup> As with consumer connection expenditure, Aurora Energy has forecast asset relocation expenditure as the average expenditure over the RY15 to RY19 period.

<sup>102</sup> It may be that raising the contribution rate will have an immaterial impact on connection expenditure (e.g. as demand may be inelastic). However, it appears to us – at the time of writing – materially likely that the economic fallout from the COVID-19 pandemic will affect connections in the short to medium term and so may materially affect connection expenditure over the CPP and review periods. However, given the timing of our verification report, we were unable to quantify this with sufficient accuracy to include in our report.

- the reasonableness of the assumed increase in the rate of contributions based on as yet unclear changes to Aurora Energy’s connection policy, especially given the potential objection that may come from stakeholders that want to promote consumer connections.

If the Commission makes changes to forecast connection and asset relocation expenditure, then it may also want to consider making corresponding changes to the capital contribution forecast.

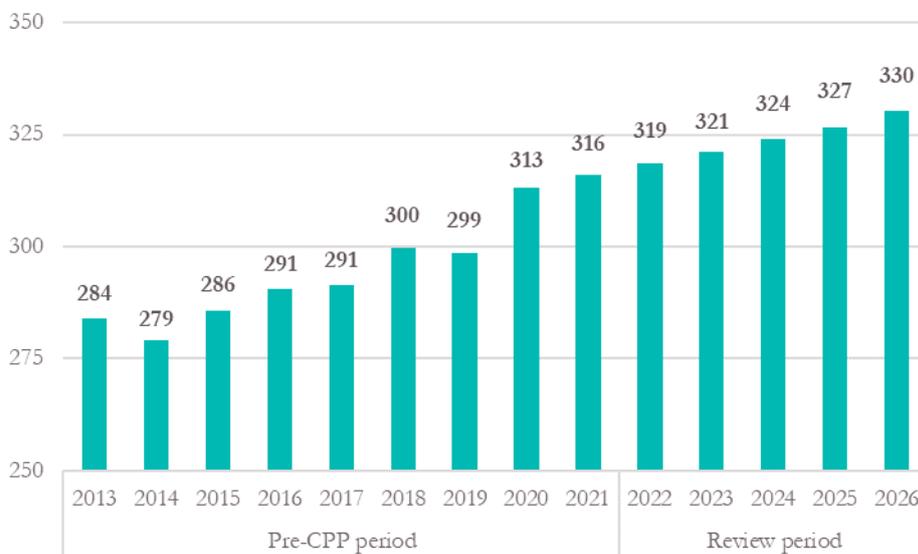
## 6.2 DEMAND

### 6.2.1 Aurora Energy’s proposal and our general observations

#### Overview of forecasts

Aurora Energy forecasts a moderate increase in peak demand over the CPP and review periods, as shown in Figure 6.3, with a noticeable step up from RY19 to RY20. Breaking the forecast down by area, shows that the Queenstown Lakes area – and to some degree the Central Otago area – is driving most of the increase while demand in Dunedin is projected to be flat.

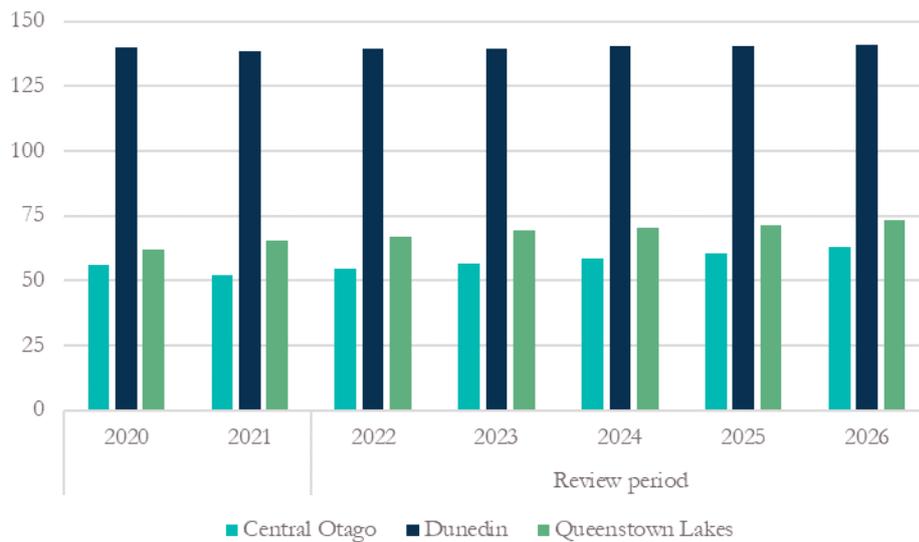
Figure 6.3 – Network demand history vs forecast



Source: Aurora Energy data. Farrierswier and GHD analysis.

- Demand shown is for maximum coincident system demand in MVA.
- Vertical axis is truncated at 250 MVA.
- The forecast does not factor in any impact from the COVID-19 pandemic.

Figure 6.4 – Network demand forecast by network area



Source: Aurora Energy data. Farrierswier and GHD analysis.

- (a) Demand shown is for maximum coincident system demand in MVA.  
 (b) The forecasts do not factor in any impact from the COVID-19 pandemic.

### Forecasting approach

Aurora Energy forecasted peak demand at the total network, supply area, grid exit point, and zone substation levels for its CPP proposal. It also prepared these for both expected peak demand (i.e. the 50<sup>th</sup> percentile) and ‘prudent’ peak demand (which is set at the 80<sup>th</sup> percentile). Each forecast was prepared independently of each other. None of the forecasts factor in any specific adjustments to capture the potential effect of the COVID-19 pandemic.

For the most part the forecasts did not directly affect the expenditure forecasts that Aurora Energy has prepared. However, the zone substation forecasts do affect the economic evaluations and other assessments used by Aurora Energy for its proposed major growth projects, including the Arrowtown 33 kV ring upgrade and Riverbank zone substation projects that we reviewed.<sup>103</sup> Specifically, the demand forecasts are inputs to the estimated economic value of reliability from undertaking those projects – which we discuss further in section 4.4 and Appendix C.

The demand forecasts for each level broadly combine five components:

- **first**, developing a modelled load forecast using SARIMAX statistical models fitted to historical data<sup>104</sup>
- **then**, adding:
  - the impact of solar generation based on the assumed uptake of solar and its contribution to peak load
  - the impact of electricity vehicles (or EVs) based on the assumed uptake of EVs and their contribution to peak load

<sup>103</sup> Following our draft report, Aurora Energy proposed deferring the Riverbank zone substation upgrade project until after the review period.

<sup>104</sup> A SARIMAX model is a seasonal autoregressive integrated moving average model with exogenous factors (or regressors), which is a generalised model that is commonly used to forecast time series data. It allows for seasonal (e.g. daily, weekly, monthly, or quarterly) variation, regression to past values, trends over time, and external variables. Although available, when fitting such a model to historical data not all components are adopted (e.g. as including them may provide a poorer fit to the data).

- any user specified step changes of which there were none in the forecasts prepared by Aurora Energy<sup>105</sup>
- irrigation forecasts for some zone substations prepared by Aqualinc.

The SARIMAX models were fitted to historical load data for the total network, and each supply area, grid exit point and zone substation using Python code that iteratively solved for the combination of external factors (or regressors) and model parameters that best fits that data.<sup>106</sup> In all cases, a subset of the possible SARIMAX model parameters and regressors was adopted by Aurora Energy after applying the iterative process, with significant variation among the fitted models.<sup>107</sup>

The solar generation and EV assumptions were drawn from several sources and differed across the five GXP's that connect to Aurora Energy's network. An S-curve was used to project penetration of both technologies over the CPP and review periods. Across all GXP's, EV penetration was assumed to reach 17% by the end of RY26; while solar penetration varied from 2.5% to 13.1% across GXP's by the end of RY26 depending on the current penetration and other assumptions.<sup>108</sup>

Forecast peak electricity demand from irrigation was prepared by Aqualinc for each zone substation based on projected land use for the area serviced and assumed irrigation requirements and delivery (e.g. pumps). Aqualinc did not forecast contribution to maximum coincident demand for each zone substation. Aurora Energy adjusted the Aqualinc forecasts to account for diversity (i.e. contribution to maximum coincident peak demand).<sup>109</sup>

No adjustments were made to the demand forecasts for weather, improvements in energy efficiency or demand side capability (e.g. ripple control), nor responsiveness to electricity prices (e.g. from more cost-reflective or higher prices). Although economic (i.e. GDP) and population trends were considered when fitting the SARIMAX models, many of the fitted models did not include them (e.g. Wanaka zone substation).<sup>110</sup>

Key assumptions underpinning the demand forecasts are:

- historical trends observed for the total network and at each supply area, GXP and zone substation are going to continue (as captured in the fitted SARIMAX models)
- electrical vehicle penetration across the network will reach 17% by the end of RY26 and solar penetration will reach between 2.5% and 13.1%
- weather, energy efficiency, demand side capability and electricity prices will not affect peak demand
- projected economic and population growth is only relevant for some supply areas, GXP's and zone substations

<sup>105</sup> Although Aurora Energy tested the impact of including a new agri processing factoring drawing up to 5 MVA from the Frankton zone substation, this was not included in the final demand forecasts adopted.

<sup>106</sup> The Python code uses the Bayesian information criterion to assess 'fit', which is one of several statistical criteria commonly used to select models.

<sup>107</sup> Such variation is not surprising given data for a given area, GXP, or zone substation varies significantly over time and correlates in different ways with available external regressors. The six regressors considered by Aurora Energy were 'GDP – Primary', 'GDP – Industrial', 'GDP – Commercial', 'GDP – Unallocated', 'GDP – Total' and 'Population'.

<sup>108</sup> For instance, solar penetration at the SDN GXP was projected to be 2.5% by the end of RY26 compared to 13.1% for the CML GXP.

<sup>109</sup> See: Aurora Energy, *P08 – Demand Forecasting*, 28 March 2020, slide 14.

<sup>110</sup> Specifically, the forecasting approach used by Aurora Energy uses two optimisation loops to fit the SARIMAX model for each area, GXP, and zone substation. One loop determines what regressors (i.e. variables) to include in the fitted model and the other determines what the model parameters should be. Applying these loops meant that the many fitted SARIMAX models did not include GDP and population trends as regressors.

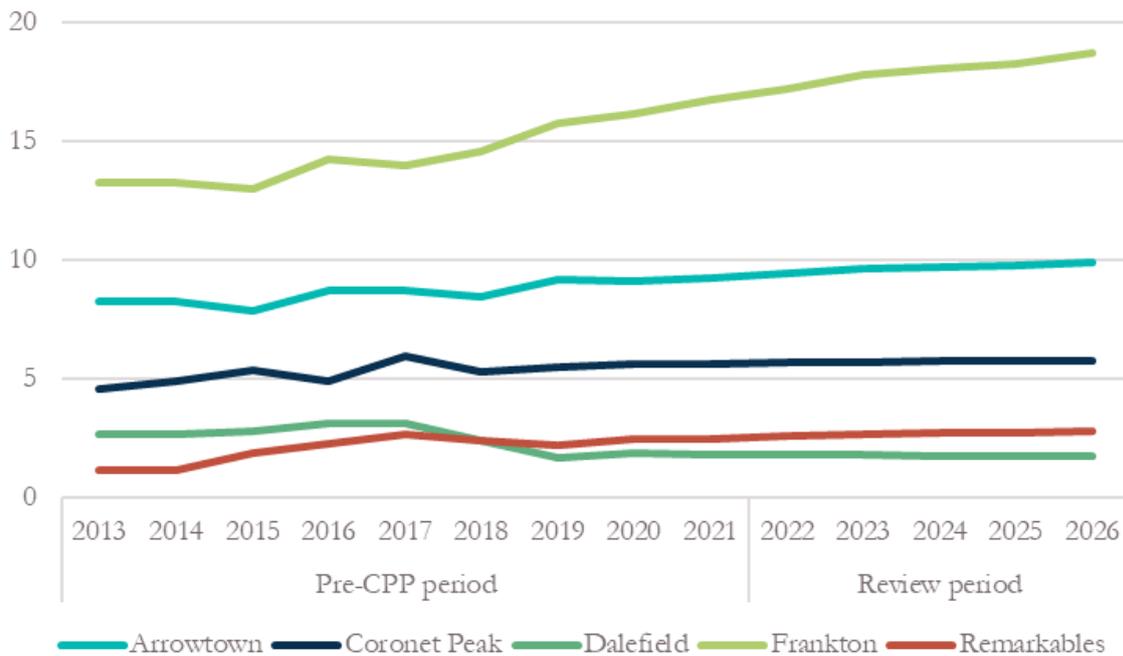
See: Aurora Energy, *Load Forecast Model Manual*, 22 October 2019, p. 11.

- peak demand for the total network and each supply area, GXP and zone substation are independent of each other.

**Forecasts relevant to the Arrowtown 33 kV ring upgrade and Riverbank zone substation upgrade projects**

Aurora Energy forecasts that the peak demand at the five zone substations that connect to the Arrowtown 33 kV ring as well as the Wanaka zone substation will increase over the CPP and review periods, as shown in Figure 6.5 and Figure 6.6. Although Aurora Energy now proposes deferring the Riverbank zone substation upgrade project until after the review period, we nevertheless review it in section C.14.

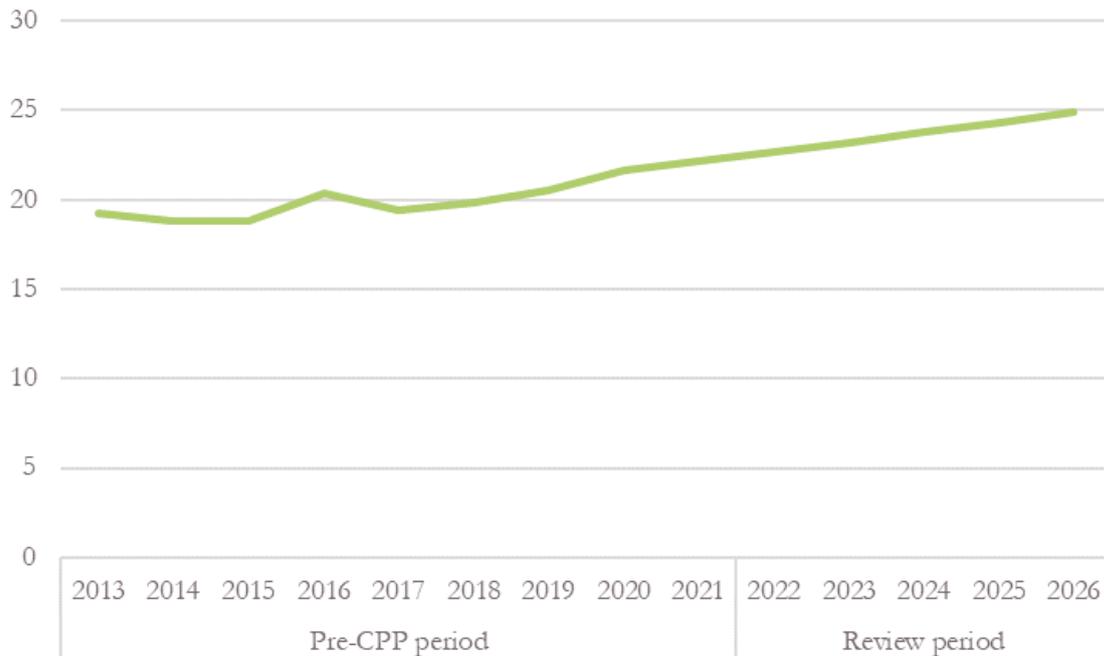
Figure 6.5 – Peak demand for Arrowtown 33 kV ring zone substations (MVA)



Source: Aurora Energy data. Farrierswier and GHD analysis.

- (a) Demand shown is for maximum coincident system demand in MVA.
- (b) The forecasts do not factor in any impact from the COVID-19 pandemic.

Figure 6.6 – Peak demand for Wanaka zone substation (MVA)



Source: Aurora Energy data. Farrierswier and GHD analysis.

(a) Demand shown is for maximum coincident system demand in MVA.

(b) The forecast does not factor in any impact from the COVID-19 pandemic.

## 6.2.2 IM requirements and our approach to assessment

This section aims to address Schedule G8(1) of the IM, and our approach to assessing compliance of Aurora Energy’s CPP against the IM requirements.

### Box 22 – IM requirements for demand

#### Schedule G8(1) of the IM:

The verifier must provide an opinion as to whether:

- (a) the **key assumptions**, key input data and forecasting methods used in determining demand forecasts were reasonable; and
- (b) it was appropriate to use the demand forecasts resulting from these methods and assumptions to determine the-
  - (i) **capex forecast**; and
  - (ii) **opex forecast**.

Our approach to assessment was:

- review the models, inputs, assumptions and computer code used to forecast demand<sup>111</sup>

<sup>111</sup> Although we have reviewed the frontend spreadsheet and the supporting Python code used to apply the SARIMAX model and combine the various forecast components, we have not undertaken a detailed model or code review and audit.

- compare the proposed demand growth to that observed historically
- identify how, if at all, the demand forecasts were used to forecast capex and opex and what impact they had
- review any explanation or justification for the proposed demand forecasts and how they were used to forecast capex and opex.

The documents and models that we reviewed are set out in Table 6.2.

**Table 6.2 – Demand documents and models provided**

Title	Reference	Date
Demand Forecast Model_manual_v2.0	IP2-92	31 January 2020
SummaryExpectedOutput	IP2-49	31 January 2020
SummaryPrudentOutput	IP2-48	31 January 2020
alf_log	IP2-53	31 January 2020
ALF_XL_Frontend_v1.12	IP2-54	31 January 2020
Input_archive	IP2-52	31 January 2020
Various other input, Python code, and executive files used to apply Aurora Energy’s forecasting model	IP2-26 to IP2-92, IP2-98 to IP2-130 (excluding those above)	31 January 2020
RFI No D115 - Aurora Irrigation Electrical Load Projections-Aqualinc RD19010-1	V-6	12 March 2020
P08 - Demand Forecasting	V-139	28 March 2020
Arrowtown Ring Forecast	PD-9	3 June 2020
2. Output Visualisation Tool	PD-10	3 June 2020
Memo Providing Additional Information Regarding Demand Forecast model	PD-11	3 June 2020

### 6.2.3 Our findings

In our view, the demand forecasting *approach* does not appear unreasonable. Nor was it unreasonable to use the forecasts generating using it to inform Aurora Energy’s assessment of potential constraints on its network.

However, given the unprecedented impact that the COVID-19 pandemic is likely to have on demand across Aurora Energy’s network area, it is likely that the forecast *levels* are overstated in many cases – at least for the next few years. Recognising this to some degree, Aurora Energy has since deferred its growth-related projects and reduced its base connection expenditure, albeit without updating the demand forecasts.

Yet, what the actual impact of the pandemic will be remains unclear to us. We are unable to comment on what any step change in forecast demand would likely be. For this reason, it would be prudent for the

Commission and / or Aurora Energy to revise the demand forecasts closer to when the CPP determination is made to incorporate the latest information available at the time.<sup>112</sup>

Moreover, in our view, the forecasts also suffer from several important limitations that may undermine their usefulness when calculating potential economic benefits from proposed major projects and assessing the risk if such projects are deferred (as Aurora Energy has done).

Our view that the forecast *approach* does not appear unreasonable is based on these findings:

- the SARIMAX statistical model is a commonly used model for forecasting time series data like peak demand
- the models appear robust (although we have not undertaken a model audit)<sup>113</sup> and consistent with what we would expect to forecast demand
- rigour appears to have gone into preparing and applying the statistical model (e.g. the frontend spreadsheet and supporting Python code) with input data sourced from credible third parties (e.g. Infometrics, Statistics New Zealand, Aqualinc and the Commission) – although third party forecasts may now be outdated given the impact of the COVID-19 pandemic<sup>114</sup>
- the irrigation forecasts prepared by Aqualinc do not appear unreasonable and were based on a reasonable methodology that considers factors directly relevant to electricity needs of irrigators (e.g. irrigation area and type, pump and water delivery efficiency, and water extraction requirements)
- the forecast trends are comparable to historical trends for the zone substations relevant to the two major projects that we reviewed (i.e. Arrowtown 33 kV ring upgrade and Riverbank zone substation upgrade).

However, we also observe several limitations with the demand forecasts, including:

- do the recent installation of some zone substations, limited historical time series data was able to be used to fit the SARIMAX model (only four years in some cases), which may undermine its accuracy when forecasting demand over a longer period (i.e. seven years out to RY26)
- many of the fitted SARIMAX models did not incorporate either, or both, forecast population or GDP growth as external variables, relying instead only on historical trends to project peak demand
- many of the fitted SARIMAX models overstated historical peak demand when compared to actual values (e.g. total network in almost all years from RY12 to RY18, Wanaka zone substation in RY17 and RY18, Coronet Peak zone substation in RY17 and RY19, and Arrowtown zone substation in RY15, RY16 and RY19),<sup>115</sup> which may therefore have overstated peak demand in the forecasts
- weather normalisation, energy efficiency, demand side capability, electricity prices, and policy and social trends except for solar and EV uptake were not directly accounted for in the demand forecasts, although this may be appropriate in some cases (e.g. where no material impact to forecast demand is expected from these trends or they are assumed to be captured in the historical trends that are projected forward)

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<sup>112</sup> For instance, at the time of writing, New Zealand had only just transitioned from level 3 to level 2 of the New Zealand Government's COVID-19 alert levels, freeing up movement and allowing many businesses to reopen. What will happen to economic activity and consumers' livelihoods is unclear.

<sup>113</sup> We understand that Aurora Energy engaged Audit New Zealand to audit key models that underpin the CPP application. We are not aware of any issues identified by this audit that relate to the demand models.

<sup>114</sup> For instance, GDP growth will almost certainly be lower than that forecast by Infometrics previously. See: Infometrics, *Media Release: Recovery likely to be slow, even with bold government initiatives*, 17 April 2020. Link: <https://www.infometrics.co.nz/media-release-recovery-likely-to-be-slow-even-with-bold-government-initiatives/>.

<sup>115</sup> This can be observed in the charts included in the 'alf\_log.html' output file generated for the demand forecasts.

- solar and EV penetration could be noticeably more or less than that assumed in the modelling, which may have a meaningful impact on the forecasts
- understandably – due to timing – the impact of the COVID-19 pandemic was not reflected in the forecasts, which may be material for some supply areas, GXPs and zone substations in the short to medium term.

For these reasons it is important that appropriate review and judgement is applied before relying on such demand forecasts. Aurora Energy advised that the zone substation forecasts are reviewed by planners with local experience and knowledge and that, where necessary, adjustments are made to account for local circumstances before using the forecasts to make investment decisions.

Although sensible, we did not see any direct evidence of this and were not able to interrogate if all local conditions have been appropriately captured in the forecasts (given the large number). In our view, it is critical that demand forecasting combines both theoretical and empirical elements.

#### 6.2.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast demand was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

Although we identified some limitations with the modelling, this is not a concern in itself as *all* forecasts suffer from limitations. One issue that the Commission should consider is the potential impact of COVID-19 on peak demand across Aurora Energy's network area and particularly in areas where major projects are proposed to address demand issues (such as the Riverbank zone substation upgrade project). This may extend to working with Aurora Energy to update the demand forecasts closer to the time of the CPP determination once more information is known.

Apart from those demand-driven major projects, the demand forecasts have an immaterial impact on Aurora Energy's expenditure forecasts. If this changes as part of the Commission's assessment of the CPP application, then it may want to focus on the limitations noted in section 6.2.3.

### 6.3 CONTINGENT PROJECTS

We are required to assess any contingent projects proposed by Aurora Energy against the requirements in clause G10 of the IM (repeated below). As Aurora Energy is not proposing any contingent projects, we did not undertake any assessment against that clause.

However, as discussed in section 4.4 and Appendix C, Aurora Energy does recognise that the unique circumstances created by the COVID-19 pandemic means that some of its proposed expenditure is contingent on events outside of its control. For instance, Aurora Energy advised that:<sup>116</sup>

*In the context of Covid, we consider that our growth-related projects/programmes have sufficient uncertainty to be considered contingent projects at this time. However, the majority of our capex programme is related to renewals and as such the proportion of growth-related capex is relatively small and would not meet the very high contingent project threshold specified in the IMs.*

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<sup>116</sup> Aurora Energy, Memo from Glenn Coates to Eli Grace-Webb, *Response to Follow-up questions prompted by Commission feedback*, 12 May 2020, p. 2.

For this reason, Aurora Energy has adjusted some expenditure forecasts to reflect the likely dampening of demand and connection growth resulting from the pandemic by deferring major growth and connection projects and reducing forecast connection expenditure.

We agree that such expenditure *is* contingent at present. Specifically, we consider that the following components of Aurora Energy's capex forecast that we have reviewed could be considered contingent projects:

- Arrowtown 33 kV ring upgrade project
- Riverbank zone substation upgrade project
- a major tourism operator's connection upgrade project.

Although outside of our scope, we also agree with Aurora Energy that the unique circumstances may warrant an alternative approach to dealing with COVID-19 related expenditure contingency over the CPP and review periods – especially where the contingent project provisions in the IM are restricted to projects over a certain value. We recommend that the Commission and Aurora Energy consider this further.

### Box 23 – IM requirements for contingent projects

#### Schedule G10 of the IM:

- (1) For each proposed **contingent project**, the **verifier** must provide an opinion as to whether that **project** satisfies the following criteria:
  - (a) it is–
    - (i) reasonably required of an EDB in meeting the **expenditure objective**;  
and
    - (ii) one that associated assets are likely to be **commissioned**,  
during the **CPP regulatory period**;
  - (b) a commencement date cannot be forecast with an appropriate degree of specificity by comparison with other proposed **projects**;
  - (c) the total of **capex forecast** and **opex forecast** in relation to the project–
    - (i) as disclosed in the **CPP proposal** exceeds 10% of the value of the **CPP applicant's** annual revenue in the most recently completed **disclosure year** in respect of an **ID determination**;
    - (ii) is reasonable in dollar terms; and
    - (iii) would be likely, when forecast with reasonable certainty, to meet the **expenditure objective**.
- (2) For each proposed **trigger event**, the **verifier** must provide an opinion as to whether it meets the requirements of clause 5.6.5(3).

## 6.4 COST ESCALATION

### 6.4.1 Aurora Energy's proposal and our general observations

Aurora Energy used forecast labour and material escalation rates to develop its capex and opex forecasts. These escalators were procured from Sapere Research Group (Sapere) and combined in its CPP BBAR model with escalation weights (or input weightings) to escalate forecast capex and opex from real 2020 dollars to nominal dollars.<sup>117</sup>

Cost escalation adds \$54.3<sup>118</sup> million to Aurora Energy's nominal dollar forecasts over the review period,<sup>119</sup> split between:

- forecast inflation – \$48.3<sup>120</sup> million
- real cost escalation – \$3.9 million – and further split into:
  - real labour cost escalation – \$6.0 million
  - real material (or non-labour) cost escalation – negative \$2.1 million<sup>121</sup>.

Cost escalation can also be split between capex (\$28.2 million) and opex (\$24.1 million).<sup>122</sup>

To prepare its labour and material escalators, Sapere relied on the sources set out in Table 6.3. All of these were dated before the COVID-19 pandemic was announced and world economies responded – and so, unsurprisingly, Aurora Energy's proposed cost escalators do not incorporate its impact. Where publicly available data was not available, Sapere used simple extrapolation and interpolation techniques to prepare forecasts, by year, out to RY30.<sup>123</sup>

**Table 6.3 – Sapere data sources**

Material and labour component	Source	Date of source
NZD-USD exchange rate and CPI	Reserve Bank of New Zealand monetary policy statement	12 November 2019

<sup>117</sup> See Sapere, *Price escalation indices for Aurora, For customised price-quality path proposal to the Commerce Commission*, 27 February 2020.

See also: Aurora Energy, *RFI No W485 - Escalators extraction for Verifier 30 Mar*, 30 March 2020; and Aurora Energy, *Attachment 2 - Escalators extraction for Verifier 11 May*, 11 May 2020.

<sup>118</sup> We have based these figures on the file 'Attachment 2 - Escalators extraction for Verifier 11 May', provided to us on 12 May 2020, which was based on expenditure forecasts that we were provided to verify. Except for the aluminium, copper, and steel commodity forecasts, we could not confirm that the forecast escalators included in that file matched those provided by Sapere.

<sup>119</sup> The impact over the CPP period is about half of that over the review period.

<sup>120</sup> We have estimated this by replacing the forecast escalators with forecast inflation included in the Sapere report and supporting spreadsheet.

<sup>121</sup> Although the nominal escalators for non-labour cost items are positive, they become negative if forecast inflation is deducted – which indicates that the cost of those items, in aggregate, is expected to increase by less than inflation over the CPP and review periods.

<sup>122</sup> These values are calculated by comparing the real \$2020 expenditure forecasts to the nominal dollar forecasts in the CPP BBAR model. The other values were calculated by systematically replacing the labour and materials cost escalators used in that model with forecast inflation.

<sup>123</sup> For instance, Sapere used linear interpolation to determine index values for aluminium, copper and iron ore indexes where these were not provided by the World Bank. Sapere also extrapolated the general labour cost index (i.e. the LCI for all sectors) using the historical 20-year compound annual growth rate (CAGR) up to 30 September 2019. Sapere then extrapolated the indexes for labour sub-categories by effectively adding an increment to the projected changes for the general labour category (i.e. the LCI for all sectors), where the increments were determined by comparing the CAGRs for each over the 10 years to 30 September 2019.

Material and labour component	Source	Date of source
Capital goods, producer price index (PPI) inputs and outputs, and labour	Commerce Commission DPP for the 2020–25 period, which was based on forecasts sourced from NZIER	27 November 2019 for DPP decision 27 August 2019 for NZIER forecasts
Aluminium, copper, and iron ore (used as a proxy for steel)	World Bank global commodities price forecasts	October 2019

Aurora Energy then applied these escalators to its capex and opex forecasts in the CPP BBAR model by:

- first, calculating escalator indices for both capex and opex inputs<sup>124</sup>
- then multiplying the real \$2020 expenditure forecast for each expenditure category by a weighted average escalator calculated as the sum product of:
  - the relevant escalator indices for either capex or opex
  - the assumed input weightings for the expenditure category.<sup>125</sup>

#### 6.4.2 IM requirements and our approach to assessment

As noted in chapters 4 and 5, the IM requires an opinion on the reasonableness of key assumptions relevant to the capex and opex forecasts respectively, including:

- the method and information used to develop them
- how they were applied
- their effect or impact on the forecasts by comparison to their effect or impact on actual capex or opex.

We consider that the labour and material escalators are key assumptions that are material to the overall capex and opex forecasts, and have therefore reviewed the assumptions in Aurora Energy’s CPP proposal.

Our approach to assessment was:

- review the source for the labour and material escalation rates – namely an independent expert report prepared by Sapere – including the assumptions, inputs and methods used to derive the rates
- compare the forecast escalation rates to those observed historically
- compare the forecast escalation rates to more recent market data
- review the weights used to combine the escalation rates before being applied to escalate the capex and opex forecasts
- identify how much impact the escalation rates had on the capex and opex forecasts.

The documents and models that we reviewed are set out in Table 6.4.

<sup>124</sup> Aurora Energy, *Attachment 2 - Escalators extraction for Verifier 11 May*, 12 May 2020; see the ‘Escalators’ sheet. At the time of writing, the escalator inputs to that spreadsheet did not appear to match those provided by Sapere. We intend to engage with Aurora Energy further on this before we finalise our final verification report.

<sup>125</sup> Aurora Energy, *Attachment 2 - Escalators extraction for Verifier 11 May*, 12 May 2020; see the ‘Forecast opex’ and ‘Forecast capex’ sheets.

Table 6.4 – Cost escalation documents and models provided

Title	Reference	Date
RFI No W484 - 20200227Aurora Energy_Escalation Indices_Final Report_27 February 2020	V-77	28 February 2020
RFI No W484 - 20200227 Annual time series for Aurora with percentage changes	V-79	28 February 2020
RFI No W485 - Escalators extraction for Verifier 30 Mar	V-142	31 March 2020
<b>Provided in response to our draft report</b>		
Attachment 2 - Escalators extraction for Verifier 11 May	PR-60	11 May 2020

### 6.4.3 Our findings

#### *Forecast escalators*

In our view, the labour and materials escalators recommended by Sapere for Aurora Energy to use when preparing its expenditure forecasts for the CPP application are no longer appropriate given the significant impact that the COVID-19 pandemic is having and likely to have on costs over the CPP and review periods.

Although Sapere’s approach to forecasting these escalators generally does not appear unreasonable, the data sources relied on are now significantly out of date – being published over August to November 2019. Moreover, given the significant value that escalation adds to the nominal capex and opex forecasts and the inherent uncertainty with them (especially the materials escalators), we recommend that the Commission consider procuring its own cost escalation forecasts (e.g. as a cross-check) or working with Aurora Energy to update its forecasts to reflect more recent information.

Our view is based on the following:

- the COVID-19 pandemic along with governmental and central bank responses is having a significant effect on global and domestic markets that is likely to affect Aurora Energy’s costs over the short to medium term<sup>126</sup> – due to the timing of Sapere’s report, this effect was not reflected in the cost escalator forecasts
- it is reasonable to apply material and labour cost escalation when forecasting capex and opex, provided that the underlying assumptions, methods, and input data are reasonable
- Sapere is a reputable third-party consulting firm, and is suitably qualified to apply econometrics and professional judgement to forecast labour and materials escalators for New Zealand
- the labour and materials escalators recommended by Sapere appear to rely on reasonable data sources (albeit now out of date) and interpolation / extrapolation methods

<sup>126</sup> For instance, the World Bank noted on 3 March 2020 that all commodity groupings that it monitors except for fertilizers and precious metals fell in February 2020. Similarly, the Reserve Bank of New Zealand reported at 26 March 2020 that the NZD-USD exchange rate has fallen dramatically over the last month and now sits at US\$0.5801 per NZD compared with US\$0.644 assumed by Sapere.

See: World Bank, *World Bank Commodities Price Data (The Pink Sheet)*, 3 March 2020;

<http://pubdocs.worldbank.org/en/541851583268074222/CMO-Pink-Sheet-March-2020.pdf>.

See also: Reserve Bank of New Zealand, *Exchange rates and TWI – B1*, <https://www.rbnz.govt.nz/statistics/b1>, accessed 26 March 2020.

- the proposed labour and other cost escalation rate forecasts appear consistent with the average rates observed over the last 15 years and are only marginally higher than forecast inflation on average
- although the proposed material cost escalation rate forecasts are broadly consistent with average rates observed over the last 15 years, there were some significant annual variances (e.g. aluminium, copper, iron ore and other capital goods) – which reinforces our view that material cost escalation rate forecasts are inherently unreliable (and much more so than labour escalation rate forecasts) and jump around from time to time given that they largely rely on the foreign price of commodities and the market forecasts that govern them<sup>127</sup>
- the escalators are sensitive to the assumed USD: NZD exchange rate, which – like material escalators – is inherently unreliable and subject to change.

Although there are several limitations with the approaches used by Sapere, we do not consider that these materially affect our view above. These limitations include:

- assuming that vegetation control costs reflect a 50/50 mix of maintenance labour and PPI input costs without any obvious justification for that assumption
- rebasing forecast indexes for labour costs, PPI, and CGPI to reflect more recent actual indexes while retaining the same forecast percentage changes without considering whether those percentage changes should be updated to reflect the updated base<sup>128</sup>
- assuming that historical labour cost growth rates over 10 and 20 years are appropriate predictors of future growth rates where labour markets have gone through – and continue to – significant changes over that period and so may be inappropriate.

### *Application of forecast escalators*

In our view, the approach used to apply the escalation rates within the CPP BBAR model<sup>129</sup> to the capex and opex forecasts generally appears reasonable because:

- the approach combines the forecast escalation rates with weights that map these to each expenditure category in a logical way
- the weights do not appear unreasonable
- the model appears robust (although we have not undertaken a model audit)<sup>130</sup> and is consistent with what we would expect to apply cost escalation to expenditure forecasts.

In providing, this view we note the following limitations:

- the cost escalators included in the ‘Attachment 2 - Escalators extraction for Verifier 11 May’ spreadsheet do not appear to match those in Sapere’s report or supporting spreadsheet for all escalators, except for aluminium, copper and steel

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<sup>127</sup> To avoid introducing forecasting error to the regulated price setting process some regulators (e.g. the AER) assume that materials escalate at inflation.

<sup>128</sup> Sapere refers to this as ‘splicing’ and describes it as:

*In the case of the LCI, PPI and CGPI, actual results have become available for the September quarter overwrite forecasts. We have taken the actual results as the new base and applied the same forecast percentage difference to the new base.*

See: Sapere, *Price escalation indices for Aurora, For customised price-quality path proposal to the Commerce Commission*, 27 February 2020, p. 5.

<sup>129</sup> Here, where we refer to the CPP BBAR model, we are basing our findings on the spreadsheet titled ‘Attachment 2 - Escalators extraction for Verifier 11 May’, which we understand is an extract from that model. We have not validated that it is.

<sup>130</sup> We understand that Audit New Zealand was engaged by Aurora Energy to audit the spreadsheets that support its CPP application, including the CPP BBAR model that applies the cost escalators to forecast capex and opex. We are not aware of any unresolved issues resulting from this audit.

- the US\$/NZ\$ exchange rate provided by Sapere does not appear to affect cost escalation when included in the ‘Attachment 2 - Escalators extraction for Verifier 11 May’ spreadsheet, even though the aluminium, copper and steel forecasts are in US\$<sup>131</sup>
- we have not been able to confirm the source for the escalation weights adopted by Aurora Energy.

#### 6.4.4 Completeness and key issues for the Commission

The information provided by Aurora Energy on cost escalators was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether the cost escalator forecasts should be updated to better reflect the potential impact of the COVID-19 pandemic
- whether it is appropriate to apply anything other than forecast inflation to non-labour costs given the inherent uncertainty in them
- confirming that the final escalators have accurately been captured in the BBAR model.

### 6.5 COST ESTIMATION

#### 6.5.1 Aurora Energy’s proposal and our general observations

The master set of building block unit rates used by Aurora Energy to generate capital renewal and major project estimates are currently based on historical project costs that have been separated into various asset category and asset type building blocks.

Consequently, although Aurora Energy has an appreciation of the types of costs – direct material, labour, overhead, and design – that may be inherent in each building block, the cost components that make up the building blocks are not well defined. This makes benchmarking Aurora Energy’s unit costs somewhat problematic, as it is difficult to ensure a like-for-like comparison.

Aurora Energy has advised that the building block unit rates are reviewed annually and are currently held in a Microsoft Excel file that is copied into estimating models, including the models underpinning the capex forecasts that we have reviewed. However, there does not appear to be a single point of control for program or project estimates, nor does there currently appear to be any management oversight on how the program or project estimates compare with actual costs.

Aurora Energy recently engaged Jacobs to review its library of unit costs (or pricebook). Following this review, Aurora Energy revised some of its unit costs where it believes doing so would improve their accuracy. In its report, Jacobs noted the lack of clarity on scope for many building block asset definitions.

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<sup>131</sup> This appears to be the case because all of the exchange rate change is projected to occur in RY20 and the spreadsheet starts escalating from RY20, which effectively means that that change is assumed to already be reflected in unescalated forecast expenditure.

However, this may not align with the available data. For instance, the current exchange rate reported by the Reserve Bank of New Zealand for 31 March 2020 – the last day of RY20 – was US\$0.5997 per NZ\$1. This compares to the US\$0.6436 per NZ\$1 forecast by Sapere for RY20 to RY26, which if accurate suggests that the exchange rate will increase from its current level.

Moreover, some expenditure forecasts are based on historical costs incurred prior to RY20. In particular, Aurora Energy has used RY19 opex as the base when forecasting expenditure for most opex programs using the base, step and trend method.

## 6.5.2 Information provided

The documents and models that we reviewed are set out in Table 6.5.

Table 6.5 – Cost estimation documents and models provided

Title	Reference	Date
P04 - Cost estimation and escalation	P04	15 March 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	RFI D293	18 March 2020

## 6.5.3 Our findings

Based on our experience with electricity utilities in New Zealand and Australia with more developed cost estimating systems, we suggest that Aurora Energy consider the following as potential initial improvement opportunities:

- There should be a custodian of the unit rates that is responsible for maintaining the data set. Only the custodian should be able to change or add building blocks. Initially the unit rates should be reviewed on a six-monthly basis by Aurora Energy to recognise any new or updated cost information that Aurora Energy may have received through the procurement of equipment and services.
- Aurora Energy should consider using the proposed asset management system to store the unit rates and building block models.
- As Aurora Energy gains a better understanding of project and program costs, building block definitions should be developed that include any inherent assumptions e.g. for a unit of 1 km length of overhead line, there should be a definition of the number and type of poles, location (urban/regional/rural), and conductor size. This will make cost benchmarking more straightforward and conclusive, as any variances found during the benchmarking process can then be identified.
- With additional data, Aurora Energy should consider underpinning the building blocks with bottom-up estimates based on materials and labour. This will make updating the unit rates more effective as changes in equipment procurement costs or labour hourly rates will be better reflected in the unit rates.
- By defining the building block component, Aurora Energy will be better able to identify and estimate project specific costs for major projects, such as accelerated construction costs, site management, traffic management, and customer liaison.
- Post-project or program reviews should be considered so that estimates prepared for major project business cases can be assessed to see how accurate these were and identify any key areas of variance.

The overall aim of improvements in cost estimation should be to improve estimating accuracy that will support better assessments of options for solutions to network needs, and drive for more cost efficiency in project and program costs.

As part of our review, there were minimal instances where we have considered changes to rates and project estimates for capex forecasts; however, the process of review was made difficult without a rigorous system in place. There remains a risk that unit rates reflected in the expenditure forecasts are not as efficient they could be.

## 6.5.4 Completeness and key issues for the Commission

As part of its review, the Commission should consider engaging with Aurora Energy to understand the current data available for establishing unit rates. It may also want to develop an approach to assess how

Aurora Energy improves the inherent accuracy and level-of-confidence in the building blocks over the CPP or review periods.

## 6.6 NETWORK RISK

### 6.6.1 Review of proposal against WSP identified risks

A key driver for Aurora Energy's CPP proposal was to address network risks identified by WSP in its state of the network review. Understandably, these risks were a concern to Aurora Energy as well its staff, customers, and other stakeholders and the Commission.

Recognising this, we assessed how Aurora Energy ascertain the network risks with newer/additional asset data and proposes to address those network risks. Our assessment is contained in Appendix F. As well as assessing how proposed asset fleet strategies and expenditure forecasts address those risks, the appendix also compares Aurora Energy's maintenance intervals to those adopted by other New Zealand EDBs and to GHD's experience working with Australian EDBs.

### 6.6.2 Our findings

In our view, based on the information provided to us, Aurora Energy's proposed expenditure for the identified projects and programs appears to adequately address the relevant risks identified by WSP.

Our view is based on the following observations:

- WSP used a more qualitative approach to assess risks within the different asset fleets whereas – with the passage of time and improved data – Aurora Energy has developed models aimed at more accurately and quantitatively determining replacement volumes
- Aurora Energy's proposed asset strategies for the asset fleets that we reviewed appear reasonable given the existing asset management system maturity, data availability, and deliverability constraints – although risks for some asset fleets are presently high, the proposed strategies appear to adequately address these
- Aurora Energy has generally nominated inspection, testing and maintenance cycles that are comparable to peers in NZ and Australia, and therefore implicitly manage the maintenance of its assets at similar risk levels to its peers
- although Aurora Energy has only explicitly considered the ALARP principle when forecasting expenditure for some asset fleets (e.g. zone substation related), the age and condition based modelling used for other fleets are based on assumptions that are consistent with those adopted by other NZ EDBs – suggesting that the forecasts themselves are consistent with the principle, even if the approach used to generate them may not consider it directly.

Our view is also subject to several limitations:

- although we have reviewed the information provided to us by Aurora Energy, we have not undertaken our own risk assessments
- we have not reviewed the WSP report to validate its findings – taking them as given – although generally the findings are consistent the areas that have been addressed by Aurora Energy.

## 6.7 PROCUREMENT AND COST CONTROL

### 6.7.1 Aurora Energy's procurement standard and approach

#### *Standard and principles*

Aurora Energy's procurement process is guided by its procurement standard (AE-SA14-S), which sets out the principles by which it operates when procuring goods or services.

These *principles* require that:

- there is sufficient advanced planning for procurement processes, including before choosing a procurement method
- all suppliers of goods and services are provided equal opportunity and treated fairly
- the right supplier is chosen, which does not always mean choosing the cheapest supplier
- total cost of ownership over the whole life of the asset is considered
- procurement processes, procedures, behaviour, and governance are consistently aligned with GEIP.

The standard:

- details the types of procurement methods that are used for different situations and for different types of expenditures
- appears flexible enough so that Aurora Energy can opt for less than optimal or non-competitive procurement methods in certain situations to manage urgent risk, meet timelines and other operational constraints
- recognises that the preferred procurement method may differ by expenditure type (e.g. network, non-network, capex, opex, and customer-initiated work) – and so provides only general guidance on which methods to employ (see next section).

#### *Methods used*

Aurora Energy uses various procurement methods, which – as summarised in Table 6.6 – differ by expenditure type. Methods include:

- direct procurement – this is used in certain instances after considering the capability and capacity of the market offerings, project timing, need for standardisation etc.
- written quotation
- market tender
- panel arrangement
- utilising the available Government contracting mechanism (e.g. 'All-of-Government', 'Open Syndicated' and 'Common Capability' contracts) – which is generally used to procure non-network goods and services such as travel services, vehicle rental, ICT hardware and software, consumables etc
- group purchasing of goods and services – as a subsidiary of Dunedin City Holding Limited, Aurora Energy can benefit from bulk-purchasing power in some cases.

When selecting a preferred method, Aurora Energy considers:

- value and expected cost
- risk
- nature of good and service being procured

- network or business constraints that it plans to address.

Table 6.6: Types of expenditure and appropriate procurement methods to employ

TYPE OF EXPENDITURE		PROCUREMENT METHODS
<b>Opex</b>	Non-network operating expenditure: <ul style="list-style-type: none"> <li>• business support</li> <li>• system operations and network support</li> </ul>	<ul style="list-style-type: none"> <li>• direct procurement – low value, low risk</li> <li>• written quotes</li> <li>• all-of-government</li> <li>• group purchasing</li> </ul>
	Network operating expenditure: <ul style="list-style-type: none"> <li>• routine and corrective maintenance and inspection</li> <li>• vegetation management</li> <li>• asset replacement and renewal</li> <li>• service interruptions and emergencies</li> </ul>	<ul style="list-style-type: none"> <li>• panel arrangement</li> <li>• direct procurement</li> </ul>
<b>Capex</b>	Customer initiated works	<ul style="list-style-type: none"> <li>• customer-led (a customer or developer may use their own designer and builder provided that they are an Aurora Energy’s Authorised Contractor).</li> </ul>
	Network and non-network capital expenditure: <ul style="list-style-type: none"> <li>• system growth</li> <li>• reliability, safety and environment</li> <li>• asset replacement and renewal</li> <li>• asset relocations</li> <li>• non-system fixed assets (i.e. IT systems, asset management systems, office buildings and furniture, motor vehicles).</li> </ul>	<ul style="list-style-type: none"> <li>• panel arrangement</li> <li>• written quotes</li> <li>• direct procurement</li> <li>• tender</li> <li>• all-of-government</li> <li>• group purchasing</li> </ul>

Source: Aurora Energy.

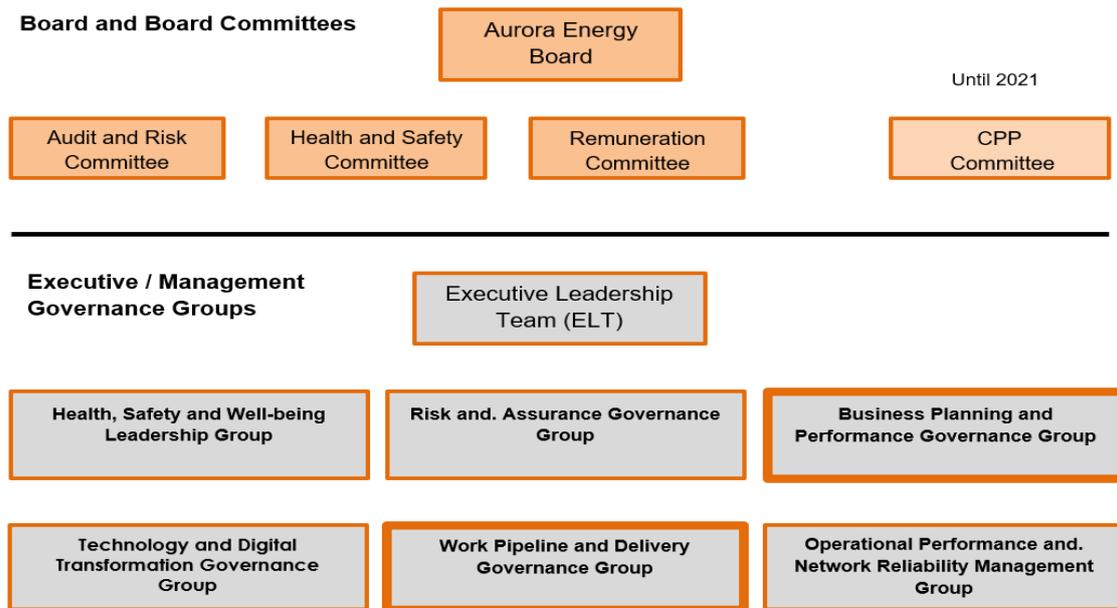
## 6.7.2 Aurora Energy’s cost controls

Aurora Energy’s manages costs through its governance framework, as summarised in Figure 6.7. Each committee and management group has terms of references that set out what role and decision-making authority they have over costs.<sup>132</sup> The business planning and performance governance group and the work pipeline and delivery governance group are focused on program management and cost controls.<sup>133</sup>

<sup>132</sup> See: Aurora Energy, *Attachment 1 - Cost control - Governance Framework*, 12 May 2020.

<sup>133</sup> See: Aurora Energy, Memo from Glenn Coates to Eli Grace-Webb, *Response to Follow-up questions prompted by Commission feedback*, p.1.

Figure 6.7: Aurora Energy governance framework



Aurora Energy has also established a framework for project management and governance, including:

- adopting a consistent project management methodology, with PRINC2 training rolled out for various staff
- rolling out Sentient as a project management tool across the business
- implementing its new FSA contracting arrangements that include KPIs and other mechanisms to ensure costs are efficient.

### 6.7.3 Our findings

We have compared Aurora Energy’s procurement standard to what we have seen in other EDBs and spoken to Aurora Energy’s management team on the methods used recently to procure ICT hardware, zone substation equipment and setting up the FSAs. We also considered Aurora Energy’s proposed procurement strategies when considering capex and opex deliverability in sections 4.5 and 5.7.

Based on this, in our view, Aurora Energy’s procurement standard and our understanding of how this is applied in practice appears reasonable and consistent with GEIP. Although we have not undertaken a detailed audit of Aurora Energy’s procurement practices, we are not aware of any instances where the standard has not been applied or has been applied inappropriately.

Similarly, Aurora Energy’s governance framework appears consistent with what we have seen in other EDBs across Australia and New Zealand. Tasking specific committees and governance groups to oversee spending decisions and tracking performance against budgets and other milestones is GEIP. Ensuring that a common project management methodology is used, with staff training and systems to support it, is also GEIP.

In our view, Aurora Energy’s governance framework and proposed project management approach appear appropriate based on the information we have seen. If these are applied through the CPP and review periods, then they should provide reasonable cost control.

## 6.8 TRACKING EXPENDITURE AND DELIVERABLES

Up until recently Aurora Energy has been limited in its ability to track and monitor the performance of its projects due to poor data quality and the lack of suitable project management tools. Over the current DPP period Aurora Energy has rolled out Sentient, a portfolio programme management (PPM) tool – which is now used across the business to create new projects and to manage and report on the projects.

Sentient PPM allows Aurora Energy to deliver consistent and comprehensible graphical reporting, including interactive bubble charts, heat maps and provides an ability to slice and dice information to meet Aurora Energy’s requirements. Aurora Energy has also established a contractor performance manager role to support the management of KPIs and oversee service provider and project performance, supported by regional delivery managers and a centralised programming team.

Over the CPP period, Aurora Energy plans to implement mature asset management practices with ability to:

- refine its asset strategies for each renewal program – such as a tiered approach and opex optimisation, seamlessly consider all the life cycle activities to inform operational decisions
- improve precision of its capital expenditure program – that is, capex optimisation or deferrals.

In the interim, Aurora Energy can and should track its asset performance and measure its performance against aspirational objectives of peer businesses within the industry to help drive the implementation of asset performance framework. For example, Aurora Energy could use measures like those set out in Table 6.7 to monitor its delivery and asset performance.

We recommend that the Commission and Aurora Energy agree what performance measures Aurora Energy could meaningfully use and what reporting the Commission would like on project costs, risks and deliverables associated with individual programs and projects utilising the Sentient PPM, and when (e.g. at the end of each regulatory year). Similarly, with asset performance measures related to the key risks for each asset portfolio.

Table 6.7: Potential performance tracking options

Type of performance	Category	Potential measures
Delivery performance	Renewal programs (earned value)	<ul style="list-style-type: none"> <li>• volumes completed compared to the target volume set out in the project schedule</li> <li>• costs completed compared to the target annual expenditure – total cost and unit cost performance</li> </ul>
	Capital projects	<ul style="list-style-type: none"> <li>• project % complete compared to the project schedule timeframe</li> <li>• project % costs complete to the estimated project costs</li> <li>• project risks related to the schedule and costs</li> </ul>

Type of performance	Category	Potential measures
	Opex programs	<ul style="list-style-type: none"> <li>• completed planned maintenance against the estimated annual maintenance</li> <li>• completed planned maintenance against the estimated annual expenditure – total cost and unit cost performance</li> <li>• outstanding defects (greater than response period)</li> <li>• program risk to schedule and costs</li> </ul>
	Other programs (milestone reporting related to key improvement outcomes)	<ul style="list-style-type: none"> <li>• development of an integrated management systems with line of sight from the policies via frameworks through to procedures, forms, and other documentation</li> <li>• asset management information system</li> <li>• asset management system, including the journey to ISO55001 certification</li> <li>• asset performance framework, including measures, monitoring and reporting</li> <li>• asset risk management framework, such as criticality and risk assessments</li> <li>• asset data requirements and integrity framework and procedures</li> </ul>
<b>Asset performance</b>	Reliability	<ul style="list-style-type: none"> <li>• network unplanned and planned reliability (which is already in place)</li> </ul>
	Asset fleet	<ul style="list-style-type: none"> <li>• unassisted failure rate</li> <li>• # of human error incidents</li> <li>• other risk performance measures relevant to safety, reliability and the environment, such as:               <ul style="list-style-type: none"> <li>– # of shocks</li> <li>– # of identified hazards as defined by an asset performance framework</li> </ul> </li> </ul>

## 7. Completeness of CPP proposal

Schedule G11 of IM requires us to assess the completeness of Aurora Energy's CPP proposal, and is repeated below.

### Box 24 – IM requirements on completeness of proposal

Schedule G11 of the IM:

A **verification report** must-

- (a) list the information in, and relating to, the **CPP proposal** provided by the **CPP applicant** to the **verifier**, that was relied upon by the verifier in fulfilling its obligations under Schedule G;
- (b) state each type of information in respect of which this schedule requires the **verifier's** consideration or opinion that the **verifier** considers has been omitted from the **CPP proposal**, including information that is incomplete or insufficient, and the relevant requirement in Part 5, Subpart 4 to provide the information in question;
- (c) where information is identified as insufficient in accordance with paragraph (b), state the nature of additional information the **verifier** considers that the **CPP proposal** requires to fulfil the information requirement in question;
- (d) state the extent to which the omission, incompleteness or insufficiency of information has impaired the **verifier's** judgement as to whether the **capex forecast** and **opex forecast** for the next period meets the **expenditure objective**; and
- (e) explain why the **verifier** has selected the **identified programmes** in accordance with clause G4(1).

Information provided to us by Aurora Energy that we relied on in preparing our final verification report is listed in Appendix A. Most of this information was provided by Aurora Energy via the SharePoint site, with read only access. We also used the SharePoint site to ask questions of and request information from Aurora Energy, with responses provided by the same system.

In our findings in chapters 1 to 6 and in conclusions from the program review in Appendix D, we noted any concerns over the omission, incompleteness or insufficiency of information that may have affected our opinions. We also recommended how the Commission may want to address this when undertaking its own assessment of the information. We have consolidated our concerns in section 7.1 below.

Finally, our approach to – and reasons for – selecting the 18 projects and programs that we did is set out in Appendix B. Aurora Energy provided us information on each of these projects and programs, with varying degrees of completeness. This information is identified in our detailed project and program review in Appendix C.

## 7.1 MATTERS FOR THE COMMISSION TO CONSIDER

Generally, the information provided by Aurora Energy on its proposed CPP was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

Table 7.1 sets out the matters that the Commission may want to consider when undertaking its own assessment of the information provided by Aurora Energy.

Table 7.1: Matters for the Commission to consider

Topic	Matters to consider	Report reference
<b>COVID-19</b>	Consider the impact of COVID-19 on Aurora Energy's costs and demand faced by Aurora Energy, at least in the short to medium term, as well as the activities that it can undertake in the near term (i.e. due to restrictions on non-essential activities), and whether some mechanism could be used to account for pandemic related uncertainty	Section 1.4
<b>Consumer consultation</b>	If the Commission does not approve Aurora Energy's proposed CPP period but rather prefers that the review period apply, what additional consultation is required to meet the IM requirements	Section 3.3.4
	Consider whether a clearer counterfactual is required (for example, based on DPP3) to show the improvements in safety and reliability outcomes that are expected from the CPP, and explore with consumers what their thoughts on the identified improvements	
	What is consumers' willingness to pay for maintaining (and potentially improving) safety and reliability outcomes	
	Consider the price impact of the CPP on Aurora Energy's customers at a more granular level to identify whether any customers are likely to receive unpalatable price increases	
	Consider the impact of COVID-19 pandemic and expected economic impact on Aurora Energy's forecasts (including the potential to defer spend) and price outcomes, and on consumer price sensitivity	
	Consider the feedback from the CAP on its experience of Aurora Energy's consultation process	
<b>Service measures</b>	What, if any, safety related service measures should be included as a reporting requirement over the CPP period	Section 3.1.4
<b>Unplanned reliability forecast</b>	<ul style="list-style-type: none"> <li>Consider whether preventative maintenance and corrective maintenance have been incorporated into the unplanned normalised reliability model adequately</li> <li>Consider how the historical ratio of pre-normalised reliability to normalised reliability is being calculated and applied to forecast normalised reliability over the CPP and review periods, including as to:</li> </ul>	Sections 3.2.4 and E.4.9

Topic	Matters to consider	Report reference
	<ul style="list-style-type: none"> <li>– the method used to determine normalised data for the historical period used in the ratio (i.e. whether it is consistent with that proposed for the DPP3 period)</li> <li>– whether the same period should be used to estimate both the normalisation factors and the non-asset category regression parameters that are used to forecast pre-normalised reliability</li> <li>• Consider whether it is appropriate for Aurora Energy’s unplanned reliability model to be weighted to RY18 to RY20 performance rather than a longer period (e.g. RY14 to RY20, or the RY16 to RY20 DPP2 period)</li> <li>• Consider why the unplanned SAIFI outcome for RY20 was relatively high and what this says about unplanned SAIFI over the CPP and review periods</li> <li>• Consider how much of the general aging of the network and any major events resulting from aging substation fleet will offset the benefits of recent past, current, and future renewal programs</li> <li>• Consider whether the contributions forecast for crossarms, poles, and conductors due to changing asset health are reasonable in comparative contribution and change over the review period</li> <li>• Consider to what extent the relative contributions to historical unplanned reliability determined by linear regression methods could be producing errors in the forecast and whether these are material to setting the targets</li> </ul>	
<b>Planned reliability forecast</b>	<ul style="list-style-type: none"> <li>• Consider whether the regression analysis should be updated to so that the ratios of forecast planned SAIFI and CAIDI contributions by category to both expenditure and renewal volumes are constant over the forecast period</li> <li>• Consider whether historical outage, expenditure, and volume data needs to be adjusted to account for pole reinforcement that did not require outages</li> <li>• Consider whether the historical outage and expenditure data should be adjusted to recognise that crossarm renewals were not previously part of a separate program – note that this matter appears to be resolved in v5.05</li> <li>• Consider whether corrective maintenance should be included in the regression models, which can impact how high storm damage in RY18 is reflected in the forecasts</li> </ul>	Sections 3.2.4 and E.5.7
<b>Quality standard variation</b>	<ul style="list-style-type: none"> <li>• If the expenditure forecasts change, consider whether the proposed unplanned SAIDI and SAIFI limits need to be adjusted to account for the changes so that they are remain realistically achievable</li> </ul>	Section 3.4.4
<b>Capex</b>	<p><b>Pole renewals</b></p> <p>Confirm with Aurora Energy its plans for an independent engineering review over the CPP period and revisit the viability of a program with Aurora Energy towards the end of the CPP period</p>	Sections C.3.1, C.3.8, D.3.8

Topic	Matters to consider	Report reference
	<p><b>Zone substation power transformers renewals</b></p> <p>Consider reviewing a few selected zone substation power transformer replacement projects for their scope, option analysis and risk assessment – and the underlying AHI and criticality modelling and the sources of inputs data – and coordination with other works to clarify the issues noted in section D.8.8</p>	Section C.8.8
	<p><b>Zone substation outdoor switchgear renewals</b></p> <p>Consider the potential scope for improvement for assessing the risk profile of this asset fleet and using it to identify and propose the forecast expenditure. This forms an integral part of Aurora Energy’s asset management journey</p>	Section C.10.8
	<p><b>Consumer connections</b></p> <ul style="list-style-type: none"> <li>• Consider what trigger or triggers should be used if the major tourism operator’s filed connection upgrade is treated as a contingent project, noting that demand at a certain level is an obvious candidate</li> <li>• Consider whether it is realistic that Aurora Energy can realise 60% contributions from consumer connections</li> <li>• Consider whether the assumed 25% reduction in consumer connection expenditure in RY22 and RY23 due to the COVID-19 pandemic are appropriate, including once more information about the potential impact of the pandemic are known</li> </ul>	Section C.15.8
	<p><b>Arrowtown 33 kV ring and Wanaka zone substation projects</b></p> <ul style="list-style-type: none"> <li>• Consider whether the demand forecast for the Arrowtown 33 kV ring or Wanaka zone substation should be updated to reflect the expected impact of the COVID-19 pandemic once more information is known (i.e. closer to when the Commission makes its CPP determination)</li> <li>• Consider what trigger or triggers should be used if the projects are treated as contingent projects, noting that demand at a certain level is an obvious candidate</li> <li>• Consider what VoLL estimate should be used to value the reliability benefits from the projects, including whether it is more appropriate to use a value based on Aurora Energy’s consumers rather than New Zealand consumers more generally</li> <li>• Consider whether, in addition to reliability, there are other benefits that come from the project that are not yet captured in the economic evaluation</li> <li>• Consider whether the 6% discount rate is appropriate given it differs from the regulated rate of return adopted by the Commission and may not reflect more recent market information</li> <li>• Consider, if the project does go ahead, how best to monitor that the project is delivered efficiently</li> </ul> <p>In addition, for the Wanaka zone substation project, the Commission may want to consider the reliability of the demand forecasts and</p>	Sections 6.3, C.13.8, C.14.8

Topic	Matters to consider	Report reference
	<p>whether more recent information increases or decreases the need for the project during the review period</p> <p><b>Renewals</b> Whether any of Aurora Energy’s renewal programs should be supported by risk assessments to confirm findings or address concerns in this report</p> <p><b>Progress reporting</b> Discussing the establishment of interim measures and targets for the CPP and review periods which would assist in understanding the residual risk and provide line of sight to the quality standards, potentially both reliability and safety measures</p>	<p>Sections C.3.8, C.4.8, C.5.8, C.6.8, C.7.8, C.8.8, C.9.8, C.10.8, C.11.8, C.12.8</p> <p>Sections 4.1.4, 6.8</p>
<b>ICT – capex and opex</b>	<ul style="list-style-type: none"> <li>Consider whether Aurora Energy’s estimated benefits from the proposed expenditure are appropriate as to timing and magnitude - engage with Aurora Energy to review the expected benefits from the proposed capex and opex initiatives, and how the actual benefits achieved will be captured and reported, especially given Aurora Energy’s cost-benefit analysis shows a negative NPV in the first five years from RY21, but a compensating large positive NPV once the next five years are included; this could then inform how what efficiency improvements should be included in any subsequent CPP application</li> <li>Consider whether these benefits have been appropriately reflected elsewhere across the capex and opex forecasts</li> </ul>	Sections 5.1.4, C.16.8
<b>Opex</b>	<p><b>Preventative maintenance</b></p> <ul style="list-style-type: none"> <li>Consider whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs</li> <li>Consider whether actual costs for preventative maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the preventative maintenance forecast for the CPP and review period are appropriate</li> <li>Consider whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements</li> <li>Consider reviewing the KPMG third party transaction report to the Aurora Energy Audit and Risk Committee and its findings in relation to the Delta rates</li> </ul>	Sections 5.1.4, C.17.8

Topic	Matters to consider	Report reference
	<p><b>Corrective maintenance</b></p> <ul style="list-style-type: none"> <li>• Consider whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs</li> <li>• Consider whether actual costs for corrective maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the corrective maintenance forecast for the CPP and review period are appropriate</li> <li>• Consider engaging with Aurora Energy to review the current status of the consumer pole population, with a particular focus on those pre-1984, and assess Aurora Energy’s proposed timing to undertaken maintenance work on them during the CPP and review periods. Also, consider whether the remediation cost should be included in the regulated cost base</li> <li>• Consider whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements.</li> </ul> <p>If not already planned, Aurora Energy should consider adopting a defect grading system together with measures to monitor backlogs and process in rectification against set timelines during the review period</p>	<p>Sections 5.1.4, C.18.8</p>
	<p><b>Reactive maintenance</b></p> <ul style="list-style-type: none"> <li>• Consider whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs</li> <li>• Consider whether actual costs for corrective maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the reactive maintenance forecast for the CPP and review period are appropriate</li> <li>• Consider whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements</li> </ul>	<p>Sections 5.1.4, C.19.8</p>
	<p><b>Vegetation management</b></p> <ul style="list-style-type: none"> <li>• Consider whether RY18 expenditure – which was used to determine the unit rate – is efficient and whether it is appropriate to use the information disclosure data to benchmark that expenditure against other EDBs</li> <li>• Consider whether additional year on year productivity improvements should be factored into the forecast to reflect performance improvements and associated reduced costs from the</li> </ul>	<p>Sections 5.1.4, C.20.8</p>

Topic	Matters to consider	Report reference
	<p>start of the CPP period, rather than gradual improvements as currently proposed by Aurora Energy</p> <p><b>People costs</b></p> <ul style="list-style-type: none"> <li>• Consider whether it is appropriate to: <ul style="list-style-type: none"> <li>– rely on board and management oversight to ensure that the step up in actual people costs in recent years is prudent and efficient</li> <li>– use a base, step and trend approach to forecast people costs given that it is effectively standing up a new team, where historical costs are less relevant</li> </ul> </li> <li>• Consider updating the base year to RY20 – which at the time of writing was not available, but which be available for the Commission’s determination</li> <li>• Consider whether the assumption that people costs will grow over the CPP and review periods in line with network scale</li> <li>• Consider the efficiency of the proposed step changes (e.g. training costs)</li> <li>• Consider the consistency between capitalised and expensed people costs across the entire capital and operating program – which we have not been able to verify</li> <li>• Consider whether the modest efficiency improvements proposed for the CPP and review period is reasonable, considering the increased expenditure in business support systems through the ICT capex portfolio</li> <li>• Although outside of our scope, if the Commission does not accept Aurora Energy’s proposal for a three-year CPP and subsequent five-year CPP, then consider whether the proposed CPP step change is still appropriate</li> </ul>	Section C.22.8
	<p><b>SONS</b></p> <ul style="list-style-type: none"> <li>• Consider whether it is appropriate to: <ul style="list-style-type: none"> <li>– rely on board and management oversight to ensure that the step up in actual SONS expenditure in recent years is prudent and efficient</li> <li>– use a base, step and trend approach to forecast SONS given that it is effectively standing up a new team, where historical costs are less relevant</li> </ul> </li> <li>• Consider whether the base year should be updated to RY20 – which at the time of writing was not available, but which will be available for the Commission’s determination</li> <li>• Consider whether the assumption that SONS expenditure will grow over the CPP and review periods in line with network scale</li> <li>• Consider what level of staffing is efficient for a network like Aurora Energy’s</li> </ul>	Section C.21.8

Topic	Matters to consider	Report reference
	<ul style="list-style-type: none"> <li>Consider how the COVID-19 pandemic may affect insurance premia over the CPP and review periods and how best to reflect this in the expenditure forecasts</li> <li>Consider the consistency between capitalised and expensed SONS costs across the entire capital and operating program – which we have not been able to verify.</li> </ul> <p>Although outside of our scope, if the Commission does not accept Aurora Energy’s proposal for a three-year CPP and subsequent five-year CPP, then consider whether the proposed CPP step change may no longer be appropriate</p> <p><b>Network growth</b></p> <p>Consider whether it is appropriate to apply a general network growth trend to individual expenditure categories, especially where network growth is unlikely to drive costs for some categories over the CPP and review periods</p>	
<b>Efficiencies</b>	<p>Consider whether Aurora Energy’s estimated benefits from the proposed expenditure are appropriate as to timing and magnitude and have these benefits have been appropriately reflected elsewhere across the capex and opex forecasts</p>	<p>Sections 5.6.3, C.16.8</p>
<b>Capital contributions</b>	<ul style="list-style-type: none"> <li>Consider the potential impact of the COVID-19 pandemic on tourism and the economy that may affect forecast connection expenditure and therefore capital contributions</li> <li>Consider the reasonableness of the assumed increase in the rate of contributions (60%) based on as yet unclear changes to Aurora Energy’s connection policy, especially given the potential push back that may come from stakeholders that want to promote consumer connection</li> </ul>	<p>Section 6.1.4</p>
<b>Demand</b>	<p>Consider the potential impact of COVID-19 on peak demand across Aurora Energy’s network area and particularly in areas where major projects are proposed to address demand issues (such as the Riverbank zone substation upgrade project)</p>	<p>Section 6.2.4</p>
<b>Cost escalation</b>	<ul style="list-style-type: none"> <li>Consider procuring cost escalator forecasts from a sufficiently qualified independent third party to compare to those proposed by Aurora Energy and to incorporate the potential impact of the COVID-19 pandemic</li> <li>Consider whether it is appropriate to apply anything other than forecast inflation to non-labour costs given the inherent uncertainty in them</li> <li>Confirm that the final escalators have accurately been captured in the BBAR model</li> </ul>	<p>Sections 5.1.4, 6.4.4</p>
<b>Cost estimation</b>	<p>Consider engaging with Aurora Energy to understand the current data available for establishing unit rates. The Commission may also want to develop an approach to assess how Aurora Energy improves the</p>	<p>Section 6.5.4</p>

Topic	Matters to consider	Report reference
	inherent accuracy and level-of-confidence in the building blocks over the CPP or review periods	
<b>Non-identified programs</b> (34% of capex and 8% of opex that we did not review)	Reviewing the remaining 34% of Aurora Energy’s capex forecasts and 8% of opex forecasts that we did not review: <ul style="list-style-type: none"> <li>• Consider examining the underlying assumptions and criteria that form the basis for expenditure forecast such as the formation of the age profile of the asset fleet, asset condition or performance scores, and the application of selected asset strategy</li> <li>• Consider benchmarking expected asset lives and replacement volumes with other EDBs as a method to assess the appropriateness of managing safety, reliability and other risks with the expenditures forecast and to identify areas requiring further review</li> <li>• Consider reviewing the estimating processes as to how unit rates have been determined – whether based on historical rates, recent competitively sourced rates or other methods – as a method to assess the efficiency of the delivery costs</li> <li>• Consider assessing the deliverability of the program of work and the procurement approach considering availability of the required technically skilled workforce and the uplift in resource requirements</li> <li>• Consider reviewing whether sound business case principles and sensitivity analysis have been used for growth and other non-identified programs</li> <li>• Consider assessing whether any of the non-identified programs, or components of them, should be considered contingent projects, especially given the presently unclear impact that the COVID-19 pandemic impact may have on economic justifications</li> </ul>	Section 4.1.4 (capex)
<b>Tracking</b>	Consider discussing with Aurora Energy what performance measures Aurora Energy could meaningfully use and what reporting the Commission would like on project costs, risks and deliverables associated with individual programs and projects utilising the Sentient PPM, and when (e.g. at the end of each regulatory year)	Section 6.8

# Appendix A Assessment techniques and information

## A.1 ASSESSMENT TECHNIQUES

Clause G9 of the IM lists several assessment techniques that we must use in completing our verification, and requires us to explain which techniques we have applied and why others were not applied. Box 25 sets out the clause G9(1) IM assessment techniques that we must consider.

### Box 25 – IM requirements for assessment techniques

#### Schedule G9(1) & (2) of the IM:

- (1) When-
  - (a) undertaking analysis and reviews of information; and
  - (b) considering the matters, required by this Schedule, the verifier must use some or all of the following assessment techniques:
    - (c) process benchmarking;
    - (d) process or functional modelling;
    - (e) unit rate benchmarking;
    - (f) trending or time-series analysis;
    - (g) high level governance and process reviews;
    - (h) internal benchmarking of forecast costs against costs in the **current period**;
    - (i) **capex category** and **opex category** benchmarking;
    - (j) **project** and **programme** sampling; and
    - (k) critiques or **independent** development of-
      - (i) demand forecasts;
      - (ii) labour unit cost forecasts;
      - (iii) materials forecasts;
      - (iv) plant forecasts; and
      - (v) equipment unit cost forecasts.
- (2) The **verifier** must explain why particular techniques listed in subclause (1) were applied and others were not applied.
- (3) Where, for the purpose of applying any of the techniques listed in subclause (1), the **verifier** uses information that is not provided to it by the **CPP applicant**, the **verifier** must, in respect of that information-
  - (a) describe in the draft verification report its nature and source and reason for wishing to rely on it;
  - (b) subject to subclause (4), provide it to the **CPP applicant**;

- (c) when finalising the **verification report**, take into account any comments made about it by the **CPP applicant** in response to the draft verification report; and
  - (d) where, notwithstanding paragraph (c), the **verifier** continues to rely on it, describe in the **verification report**-
    - (i) the nature and source of the information relied upon and the reason for relying on it; and
    - (ii) the **CPP applicant's** concerns in respect thereof.
- (4) Subclause 3(b) does not apply if the **verifier's** terms of use of the information prevent such disclosure.

In completing our assessment, some of the above assessment techniques were applied (as either primary or supporting) and others were not. An explanation of reasons for our approach is contained in Table A.1.

**Table A.1: Assessment techniques applied**

Technique from IM	Extent applied by us	Reasons why used / not used
Process benchmarking	Supporting assessment technique	<p>We used process benchmarking to support our qualitative review of Aurora Energy's:</p> <ul style="list-style-type: none"> <li>• asset strategy planning</li> <li>• demand forecasting</li> <li>• project or program options and sensitivity analysis</li> <li>• risk assessment processes</li> <li>• deliverability approaches</li> </ul> <p>against GEIP.</p>
Process or functional modelling	Primary assessment technique	<p>We undertook asset strategy process review to validate renewal model methods, quality of input data and model integrity.</p> <p>Sensitivity on expenditure forecasts of various Aurora Energy models (selected renewal programs and growth projects) to different assumptions and scenarios was also tested.</p> <p>We applied also developed alternative models to assess validity of planned and unplanned reliability forecasts.</p>

Technique from IM	Extent applied by us	Reasons why used / not used
Unit rate benchmarking	Primary assessment technique	<p>We used available industry unit expenditure rates to validate particular Aurora Energy forecast unit rates, including:</p> <ul style="list-style-type: none"> <li>• crossarms</li> <li>• LV enclosures</li> <li>• substation power transformers</li> <li>• zone substation indoor and outdoor switchgear</li> <li>• protection relays,</li> <li>• pole top / crossarm inspections</li> <li>• air break switch maintenance</li> <li>• consumer owned pole and line inspections and remediations</li> <li>• distribution conductor inspections</li> <li>• LV enclosure inspections</li> <li>• vegetation management costs per kilometre of affected line.</li> </ul>
Trending or time-series analysis	Primary and secondary assessment technique	<p>We used this a primary technique to ascertain the level of change proposed during and after the CPP and review periods and to understand what projects or programs to nominate for independent verification.</p> <p>We also used it as a secondary technique to assess Aurora Energy’s base-step-trend forecast of opex expenditure (i.e. SONS, people costs and network maintenance opex categories) and ICT expenditure.</p>
High level governance and process reviews	Primary assessment technique	<p>We used the technique to understand the level of rigour behind the forecasts prepared over the CPP and review periods and whether:</p> <ul style="list-style-type: none"> <li>• they reflect interdependencies with other categories</li> <li>• they are likely to change once further analysis or internal review or approval is undertaken</li> <li>• forecasting assumptions and techniques used are reasonable to meet the expenditure objective.</li> </ul> <p>Given the nature of consumer connection and ICT expenditure, we also used this assessment technique to analyse and consider the effectiveness of Aurora Energy’s proposed expenditure.</p>

Technique from IM	Extent applied by us	Reasons why used / not used
Internal benchmarking of forecast costs against costs in the current period	Supporting assessment technique	<p>We used the following internal benchmarking in our reviews:</p> <ul style="list-style-type: none"> <li>the process of how forecast expenditures reflect efficiencies or inefficiencies of scale or different procurement methods to set forecast unit cost rates against historical</li> <li>the independent engineering consultant (Jacobs) review of Aurora Energy's pricebook used to validate unit rates</li> <li>the internal independent benchmarking of salaries to benchmark overhead salaries in the SONS and people costs forecasts</li> <li>the internal justification process for step changes in SONS overhead costs.</li> </ul>
Capex category and opex category benchmarking	Supporting assessment technique	<p>While recognising its limitations, we used this technique to help inform our review of whether Aurora Energy's forecast renewals and opex categories appear to be efficient or inefficient compared to its peers.</p> <p>As Aurora Energy was unable to provide specific risk assessments for most renewal capex categories, we used this technique to also validate asset strategies and benchmark replacement rates with other EDBs to assess whether residual risks are not unreasonable.</p>
Project and program sampling	Primary assessment technique	<p>This was our primary assessment technique. As well as being required by Schedule G4 of IM to inform our conclusion of whether the proposed expenditure in key categories deemed material meets the expenditure objective, we also considered it necessary to support the other areas of the IM that we must opine on.</p>
<p>Critiques or independent development of:</p> <ul style="list-style-type: none"> <li>demand forecasts</li> <li>labour unit cost forecasts</li> <li>materials forecasts</li> <li>plant forecasts, and</li> <li>equipment unit cost forecasts</li> </ul>	Supporting assessment technique	<p>We critiqued the forecast expenditure as to whether it reflected efficiencies or inefficiencies due to factors such as scale, different procurement methods or realistic/actual unit rates/escalation rates</p> <p>We also critiqued:</p> <ul style="list-style-type: none"> <li>the demand methodology developed for and used by Aurora Energy, and the inputs used and outputs generated</li> <li>capital contribution forecast method, inputs, and outputs</li> <li>the labour and material cost escalator forecasts (provided by Sapere)</li> <li>the unit rates (including as reviewed by Jacobs).</li> </ul> <p>We also developed and applied adjusted planned and unplanned network reliability forecasts.</p>

## A.2 USE OF INFORMATION

We relied on a range of information to undertake our verification. Most of this information was provided by Aurora Energy, either as part of the CPP proposal or separately in response to information requests or questions.

Information not provided by Aurora Energy that we relied upon mainly comprised benchmarking and industry data sourced from Australian and New Zealand regulators on comparable EDBs.

Clause G11 of the IM (repeated below) requires our verification report to address matters relating to information – which we do as follows:

- Appendix I lists the information in and relating to the CPP proposed provided by Aurora Energy that we relied upon in preparing our verification report, including any information used that was not provided to us by Aurora Energy (e.g. information disclosures published by the Commission)
- chapter 7 assesses the completeness of Aurora Energy’s CPP proposal
- each chapter on service measures, levels and quality standards, capex, opex, demand, capital contributions and contingent projects identifies:
  - information that we consider is omitted, incomplete or insufficient
  - the nature of any information required to fulfil the information requirement in question
  - the extent to which the omission, incompleteness or insufficient of information has impaired our verification
- Appendix B explains our selection of projects and programs.

### Box 26 – IM requirements on completeness of proposal

#### Schedule G11 of the IM:

##### A verification report must-

- (a) list the information in, and relating to, the **CPP proposal** provided by the **CPP applicant** to the **verifier**, that was relied upon by the verifier in fulfilling its obligations under Schedule G;
- (b) state each type of information in respect of which this schedule requires the verifier's consideration or opinion that the **verifier** considers has been omitted from the **CPP proposal**, including information that is incomplete or insufficient, and the relevant requirement in Part 5, Subpart 4 to provide the information in question;
- (c) where information is identified as insufficient in accordance with paragraph (b), state the nature of additional information the **verifier** considers that the **CPP proposal** requires to fulfil the information requirement in question;
- (d) state the extent to which the omission, incompleteness or insufficiency of information has impaired the verifier's judgement as to whether the **capex forecast** and **opex forecast** for the next period meets the **expenditure objective**; and
- (e) explain why the verifier has selected the **identified programmes** in accordance with clause G4(1).

# Appendix B Program selection

## B.1 INTRODUCTION

As part of our verification, we must nominate – to Aurora Energy – up to 20 projects or programs that form part of Aurora Energy’s forecast capex and opex that we then review before forming a view on whether these forecasts satisfy the expenditure objective. We cannot vary our selection of projects or programs once nominated.

This appendix sets out the requirements that we must follow when selecting these projects or programs and how we gave effect to them.

## B.2 REQUIREMENTS

Box 27 sets out requirements in clause G4 of the IM to nominate up to 20 projects and / or programs for detailed review to support our verification.

### Box 27 – IM requirements for selecting identified projects and programs

#### Schedule G4 of the IM:

- (1) For the purposes of the reviews under clauses G5(1)(d) and G6(1)(g), the **verifier** must select no more than 20 **projects** or to **programmes** be ‘identified programmes’.
- (2) In determining which, and how many, **projects** or **programmes** to select as **identified programmes**, the **verifier** must consider–
  - (a) the long term interests of **consumers**;
  - (b) the **Commission’s** ability to effectively review whether the **CPP applicant’s capex forecast** and **opex forecast** are consistent with the **expenditure objective**;
  - (c) the **CPP applicant’s** rationale for seeking a CPP;
  - (d) its ability to provide an opinion on whether the **capex forecast** information in the intended **CPP proposal** has been prepared in accordance with the **policies** and **planning standards**–
    - (i) in aggregate; and
    - (ii) for each of the **capex categories**;
  - (e) its ability to provide an opinion on whether the **opex forecast** information in the intended **CPP proposal** has been prepared in accordance with the **policies** and **planning standards**–
    - (i) in aggregate; and
    - (ii) for each of the **opex categories**;
  - (f) its ability to assess any quality standard variation proposed; and
  - (g) the materiality of the programmes or projects to the CPP proposal, the **capex forecast** and the **opex forecast**.

- (3) The **identified programmes** selected in accordance with subclause (1) must address-
  - (a) a key risk that the **CPP applicant** is exposed to;
  - (b) a key driver of the need to submit a **CPP proposal**; or
  - (c) an **obligation** that has a significant impact in the context of the **CPP applicant's overall business**.
- (4) The verifier must -
  - (a) notify the **CPP applicant** of its select **projects** or **programmes**; and
  - (b) not change its selection after such notification.

### B.3 OUR SELECTION APPROACH

We nominated the 18 projects and programs identified in Table B.1, with power transformers and indoor switchgear included within zone substations. We identified these projects and programs having regard to the requirements set out in clause G4, as required by clause G11(e). Our detailed review of these projects and programs is contained in Appendix C and Appendix D and our findings are summarised in chapters 4 and 5 on capex and opex respectively.

Table B.1: Selected projects and programs

Project or program	Category
<b>Capex</b>	
C1. Poles	Renewals
C2. Crossarm	Renewals
C3. Distribution conductor	Renewals
C4. LV conductor	Renewals
C5. Zone substation (power transformers and indoor switchgear)	Renewals
C6. LV enclosure	Renewals
C7. Protection	Renewals
C8. Arrowtown 33 kV ring upgrade	Major growth
C9. Riverbank upgrade	Major growth
C10. Consumer connections	Other network capex
C11. IT capex	Non-network capex
<b>Opex</b>	
O1. Preventative maintenance	Network opex
O2. Corrective maintenance	Network opex

Project or program	Category
O3. Reactive maintenance	Network opex
O4. Vegetation management	Network opex
O5. System operations and network support	Non-network opex
O6. People costs	Non-network opex

### B.3.1 The starting point

The proposed CPP period covers the three-year period from 1 April 2021 and includes approximately \$381.8 million of capital and operating expenditures, compared to \$426.2 million for the previous five-year DPP period.<sup>134</sup> The five-year review period adds a further two years, increasing total expenditure to \$606.5 million.

Aurora Energy’s consultation and supporting material explains that the increased CPP investment is associated with:

1. addressing safety concerns
2. abating deteriorating network reliability
3. preparing the network for the future.

As part of our verification, we need to understand the projects or programs that make up this expenditure. This will help us assess whether Aurora Energy’s expenditure forecasts satisfy the expenditure objective and promote the long-term interests of consumers.

Aurora Energy needs to demonstrate the trade-off to consumers between the expenditure proposed – and the impact on prices – and the service outcomes that result. Aurora Energy has consulted on this to some degree with consumers on this trade-off, but this should also form a key consideration when selecting the projects or programs.

### B.3.2 Approach

Drawing from the above discussion, we adopted a simple three-step selection approach to identifying projects or programs.

1. **Materiality** – identify the projects and programs that:
  - a. make up a material portion of Aurora Energy’s expenditure forecasts – 5% or more of total expenditure, or
  - b. reflect – or form part of – a material step up in spend for a given expenditure category – 30% or more in real terms and greater than \$1 million
2. **Driver** – of those projects and programs, shortlist only those that address:
  - a. a key risk that Aurora Energy is exposed to

<sup>134</sup> The \$426.2 million covers the DPP period from RY16 to RY20. At the time of writing, the RY20 value is an estimate provided by Aurora Energy.

- b. a key driver of the need to submit a CPP proposal, or
  - c. an obligation that has a significant impact in the context of Aurora Energy’s overall business
3. **Identification** – of the shortlisted projects and programs, select those – up to a maximum of 20 – that:
- a. most closely align to the rationale for Aurora Energy’s intended CPP application
  - b. link to a proposed quality standard variation
  - c. we consider necessary to provide an opinion on whether Aurora Energy’s expenditure forecasts satisfy the expenditure objective, were prepared in accordance with Aurora Energy’s policies and procedures, or promote the long-term interests of consumers, or
  - d. that has the greatest impact on prices faced by consumers over the next regulatory period.

A further consideration is how to deal with interactions between proposed capex and opex. For instance, renewing or replacing assets to reduce asset failures may well lead to lower reactive maintenance opex.

## B.4 SELECTED PROJECTS AND PROGRAMS

Table B.2 shows our assessment of the projects and programs proposed by Aurora Energy using the approach described above. The projects and programs were identified using the spreadsheet provided by Aurora Energy on 10 October 2019 and updated on 14 October 2019, which listed 48 projects and programs.

After applying the above approach, we identified 18 projects and programs for detailed review. We nominated these programs and projects to Aurora Energy on 21 October 2019 via email. Subsequently, two changes to the structure of the identified projects and programs meant that we effectively reviewed 20 from Aurora Energy’s spreadsheet. Namely:

- **Zone substations.** Aurora Energy advised that two of the programs identified – power transformers and indoor switchgear – were being combined with outdoor switchgear into a zone substation program.
- **ICT capex and opex.** Understandably, Aurora Energy considers its ICT capex and opex together as often businesses can choose between capex and opex solutions. Although we only identified the ICT capex program, the information provided by Aurora Energy – which we reviewed – covered both ICT capex and ICT opex.

Relatedly, after our draft report, Aurora Energy decided to defer the Riverbank zone substation upgrade project that we had identified due to the potential impact of the COVID-19 pandemic. However, given that it could nevertheless be considered a contingent project we have retained our review of it within Appendix C.

These changes meant that although we list only 17 projects and programs in Appendix C, our review covered 20. Based on the forecasts we have reviewed, the identified projects and programs account for 76.4% of Aurora Energy’s forecast expenditure over the CPP period, net of contributions and cost escalation, or 65.8% of capex and 92.0% of opex.<sup>135</sup>

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<sup>135</sup> For the review period, the identified projects and programs account for 76.4% of total expenditure, with 65.7% of capex and 91.7% of opex. These percentages differ from those that we considered when selecting the identified projects and programs as they were based on an earlier version of Aurora Energy’s forecast expenditure.

In making our selection we were mindful that:

- as we could only nominate up to 20 projects and programs of the 48 identified by Aurora Energy there were always going to be significant components of the proposed expenditure that we were not going to subject to detailed review
- safety was a key driver and so it was important to focus on fleets directly relevant such as poles, crossarms, conductors, protection and LV enclosures, as well as zone substations
- significant uplifts in expenditure have been proposed for LV enclosures, LV conductors and protection hence adding to the decision to include these programs
- the nine major growth-related projects only contributed 4% to total opex and capex over the CPP period – and so we considered selecting the two largest projects would give us sufficient insight into how Aurora Energy assessed these types of projects generally
- Aurora Energy was proposing to move from a reactive to preventative approach to maintenance, which is why we identified all three maintenance programs along with vegetation management
- Aurora Energy was proposing significant spend on the systems and people needed to improve its asset management maturity and so identified programs such as ICT capex, SONS and people costs that directly support that journey.

Table B.2: Assessment of projects and programs

Name	Step 1 - Materiality		Step 2 – Expenditure driver			Step 3 – Other considerations			Select
	Share of total spend (%)	Five-year step change (%)	Address key risk	Address key driver for CPP	Address significant obligation	Aligned to CPP rationale	Linked to quality standard variation	Necessary to form opinion	
<b>Capex</b>									
Poles	10%	-20%	✓ (Safety)	✓	✓	✓	✓	✓ (assess risk)	✓
Crossarms	5%	270%	✓ (Safety)	✓	✓	✓	✓	✓	✓
Subtransmission conductor	2%	-10%			✓		✓		
Distribution conductor	4%	310%	✓ (Safety)	✓	✓	✓	✓	✓	✓
Low voltage conductor	3%	1280%	✓ (Safety)	✓	✓			✓	✓
Subtransmission cable	3%	180%							
Distribution cables	1%	170%	✓ (Safety)	✓	✓	✓			
Low voltage cables	<1%	150%							
Power transformers	4%	210%	✓ (Reliability)	✓	✓		✓	✓	✓
Indoor switchgear	3%	80%	✓ (Safety)	✓	✓		✓		✓
Outdoor switchgear	<1%	90%	✓ (Safety)	✓					✓

Name	Step 1 - Materiality		Step 2 – Expenditure driver			Step 3 – Other considerations			Select
	Share of total spend (%)	Five-year step change (%)	Address key risk	Address key driver for CPP	Address significant obligation	Aligned to CPP rationale	Linked to quality standard variation	Necessary to form opinion	
Ground mounted switchgear	1%	110%	✓ (Safety)	✓	✓				
Pole mounted fuses	<1%	190%							
Pole mounted switches	<1%	240%							
Low voltage enclosures	2%	430%	✓ (Safety)	✓				✓ (assess risk)	✓
Ancillary distribution substation equipment	1%	300%							
Ground mounted distribution transformers	<1%	280%							
Pole mounted distribution transformers	2%	220%							
Protection	3%	150%	✓ (Safety)	✓	✓	✓	✓	✓ (assess risk)	✓
DC systems	1%	40%							
Remote terminal units	<1%	-60%							
Arrowtown 33 kV ring upgrade	\$7,030,000	\$9,547,000	✓ (security of supply)	✓	✓		✓	✓ (assess approach)	✓

Name	Step 1 - Materiality		Step 2 – Expenditure driver			Step 3 – Other considerations			Select
	Share of total spend (%)	Five-year step change (%)	Address key risk	Address key driver for CPP	Address significant obligation	Aligned to CPP rationale	Linked to quality standard variation	Necessary to form opinion	
Arrowtown zone substation 33 kV indoor switchboard	\$2,096,600	\$2,096,600	✓ (security of supply)	✓					
Oamkau new zone substation	\$1,577,000	\$2,628,410	✓ (security of supply)	✓		✓			
Riverbank new transformer	\$4,496,000	\$4,496,000	✓ (security of supply)			✓		✓ (assess approach)	✓
Lindis crossing second transformer	\$3,890,250	\$3,890,250	✓ (security of supply)						
Clyde-Earnsclough new transformer	\$3,487,400	\$3,487,400	✓ (security of supply)	✓		✓			
Upper Clutha 66 kV line	\$529,200	\$882,000	✓ (security of supply)	✓	✓	✓			
New upper Clutha voltage support	\$1,347,000	\$17,959,500	✓ (security of supply)						
Frankton zone substation upgrade	\$700,000	\$700,000	✓ (security of supply)						
Distribution & LV reinforcement	2%	30%	✓ (Reliability)	✓	✓	✓			
Consumer connections	4%	-30%			✓	✓		✓ (link to capcons)	✓

Name	Step 1 - Materiality		Step 2 – Expenditure driver			Step 3 – Other considerations			Select
	Share of total spend (%)	Five-year step change (%)	Address key risk	Address key driver for CPP	Address significant obligation	Aligned to CPP rationale	Linked to quality standard variation	Necessary to form opinion	
Asset relocations	<1%	-70%			✓				
RSE	<1%	-70%					✓		
Network transformation capex	<1%	-70%				✓			
IT and OT	5%	130%		✓		✓		✓	✓
Facilities	<1%	140%							
<b>Opex</b>									
Network transformation opex	<1%	180%				✓			
Preventative maintenance	6%	40%	✓ (Safety)	✓	✓			✓ (AM approach)	✓
Corrective maintenance	1%	70%	✓ (Safety)	✓	✓			✓ (AM approach)	✓
Reactive maintenance	4%	10%	✓ (Safety)	✓		✓	✓	✓ (AM approach)	✓
Vegetation	4%	0%	✓ (Safety)	✓	✓	✓	✓		✓
SONS	12%	30%	✓ (Safety)	✓	✓			✓ (AM maturity)	✓

Name	Step 1 - Materiality		Step 2 – Expenditure driver			Step 3 – Other considerations			Select
	Share of total spend (%)	Five-year step change (%)	Address key risk	Address key driver for CPP	Address significant obligation	Aligned to CPP rationale	Linked to quality standard variation	Necessary to form opinion	
People costs	6%	10%	✓ (Safety)	✓				✓ (AM maturity)	✓
IT opex	2%	40%				✓			✓ (indirectly)
Premises and plant	1%	20%							
Administration and governance	2%	20%			✓				

# Appendix C Identified program review

## C.1 INTRODUCTION

This appendix provides the outputs from our detailed review of each selected project and program. These outputs are presented against a common template and in the order shown in Table C.1, starting with those from the capital program.

Appendix C reviews each program in detail with respect to Schedule G5(1) and (2) and G6(1) and (2) of the IM and directly supports the summary of identified programs in sections 4.4 and 5.5. Within this appendix we provide our opinion as to whether Aurora Energy’s forecast of expenditure for each identified program meets the expenditure objective. This includes verifying whether:

- relevant policies and planning standards have been applied appropriately
- the process undertaken are reasonableness in determining cost-effectiveness of the chosen solution, and whether
- the project capital costing methodology and formulation, including unit rate sources, produce efficient costs and the level of contingencies are reasonable.

Appendix D addresses in more detail the verification requirements of Schedule G5(1)(f) of the IM to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast and directly supports the summary of asset replacement models in section 4.6. It follows an asset strategy approach to the assessment of the inputs used within the model, assumptions, and the modelling methods used to forecast replacement volumes related to the expenditure forecasts.

Appendix D also supports the findings in this Appendix C associated with the renewal programs.

Table C.1: Selected projects and programs

Project or program	Category
<b>Capex</b>	
C1. Poles	Renewals
C2. Crossarm	Renewals
C3. Distribution conductor	Renewals
C4. LV conductor	Renewals
C5. Zone substation	Renewals
C5.1 Buildings	Renewals
C5.2 Power transformers	Renewals
C5.3 Indoor switchgear	Renewals
C5.4 Outdoor switchgear	Renewals
C6. LV enclosure	Renewals

Project or program	Category
<b>Capex</b>	
C7. Protection	Renewals
C8. Arrowtown 33 kV ring upgrade	Major growth
C9. Riverbank upgrade	Major growth
C10. Consumer connections	Other network capex
C11. IT capex (and opex)	Non-network capex
<b>Opex</b>	
O1. Preventative maintenance	Network opex
O2. Corrective maintenance	Network opex
O3. Reactive maintenance	Network opex
O4. Vegetation management	Network opex
O5. System operations and network support	Non-network opex
O6. People costs	Non-network opex

## C.2 GENERAL OBSERVATIONS

### C.2.1 Renewal programs

Aurora Energy does not have asset performance measurements in place for its renewal programs. We understand that the main reason for this is the lack of data for asset criticality assessment and the risk assessment methodology. This means that Aurora Energy is unable to objectively articulate and demonstrate the ALARP balance achieved by the proposed expenditure for each renewal program and consequently there is some potential for risk averse forecasts or the opposite. We have used benchmarking to assess the prudence of the forecasts and have provided our reasoning for accepting, or not, the forecast based on this approach.

Aurora Energy in the near term is expected to have more mature asset management practices with the ability to refine its asset strategy (i.e. tiered approach and opex optimisation, seamlessly considering all the life cycle activities to inform operational decisions) for each renewal program and to improve precision of its capital expenditure program (i.e. capex optimisation or deferrals). This expectation of its asset management maturity journey is also aligned with its proposal for the three-year CPP period which will allow the Commission to re-assess its status and performance in a timely fashion.

Asset performance measurements for each of the fleet will need to be implemented within an appropriate asset performance framework. We expect Aurora Energy to establish asset performance measurements that reflects desired safety outcomes, supply reliability, asset failure rates, VoLL etc. in the future.

Aurora Energy also plans to develop an asset criticality framework which will further develop the work done to date for some asset fleets to encompass others assets for both risk assessments as part asset strategy development, renewal forecasting, and for prioritising delivery programs.

### C.3 POLES RENEWAL (C1)

Table C.2: Verification summary – Poles renewal (\$2020, \$millions)

<b>Expenditure category</b>	Poles renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$35.2 million Review period: \$47.9 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$35.2 million Review period: \$44.6 million	<b>Unverified</b> CPP period: \$0 million Review period: \$3.3 million
<b>Expenditure outcome assessment</b>	<p>This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure</p> <p>We accept the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review</p> <p>We accept the proposed forecast volume based on our assessment of the following factors:</p> <ul style="list-style-type: none"> <li>the need for Aurora Energy to first confirm the viability and safety concerns related to a pole reinforcement strategy over the CPP period</li> <li>asset age information and assumptions</li> <li>modelling logic and input data quality used in the wood pole survivor curve and statistical replacement profile for steel and concrete poles</li> </ul>	<p>Aurora Energy has not included any pole reinforcement in its forecast expenditure. After an engineering review and further testing we consider that Aurora Energy should find that a business case exists to adopt such a strategy after the CPP period.</p> <p>We recommend that the Commission review the potential for Aurora Energy to adopt a wood pole reinforcement strategy from RY25 onwards or earlier.</p> <p>It is expected that Aurora Energy would have improved asset condition data and refined its asset strategy by the end of the CPP period based on the knowledge gained and engineering assessments that are expected to be conducted by Aurora Energy.</p> <p>The unverified amount in the review period is based on assuming 20% of the wood pole fleet are reinforced in the pole renewal forecast model MOD01 from RY25 onwards (refer to section D.3).</p>
<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We considered WSP’s independent review of network risk with this fleet and suggested recommendations</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up and improve asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.</p>	

<b>What needs to be done</b>	Consider wood pole replacement vs. reinforcement strategy to defer or smooth the pole renewal investment forecast from RY25 onwards. It is expected that from the knowledge gained during the recent FFTP and that during the proposed CPP period Aurora Energy will refine the asset strategy based on an engineering review and risk assessment of the reinforcement methodology.
<b>Potential scope for improvement</b>	<ul style="list-style-type: none"> <li>• Aurora Energy should diligently and accurately capture and build-up asset attribute, condition and performance information to enable accurate health and criticality assessment. Aurora Energy should simultaneously consider both failure probability (proxy by asset health) and failure consequence (proxy by criticality) for robust risk assessment thereby refining the expenditure forecast precision and the asset strategy for targeted risk mitigation. This will result in refinement and optimisation of pole asset strategy in the future.</li> <li>• Undertake further forensic studies to inform whether Aurora Energy’s pole testing program should be refined (e.g. by using new testing technology).</li> <li>• Further, the business case for safety risk driven expenditure should be better articulated with rich asset attribute, condition and performance data that allows for robust risk assessments. This will also enable objective assessment of ALARP position (i.e. cost vs safety benefit balance).</li> <li>• Establish asset performance measurements that reflects safety outcomes, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a ‘line of sight’ and drive asset management improvements.</li> </ul>

### C.3.1 Project description

This is an ongoing program of work with a proposed replacement of an average of 960 poles per annum<sup>136</sup> over the CPP period, after which time replacement numbers will reduce to a lower steady state level of approximately 470 poles per annum. Renewals are full pole assemblies (with cross-arms) and may include replacement of pole mounted equipment such as distribution transformers if these are also assessed as being at end of life. The actual replacement work is prioritise based on location criticality assessment.

In the recent past (i.e. in 2018 and 2019) Aurora Energy delivered a ‘Fast Track Pole Program’ (FTPP), which involved replacing in average of 2,000 poles per annum to arrest the increasing and heightened safety risk due to the ageing pole fleet.

### C.3.2 Cost estimate / expenditure forecast

Table C.3 shows the forecast expenditure during the CPP and review periods.

<sup>136</sup> Replacement being proposed within this renewal programme only. Aurora Energy is also proposing to replace poles within other programmes such as reconductoring which is outside this renewal program.

Table C.3: Forecast expenditure – poles renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	12,780	11,472	10,908	6,660	6,048	35,160	47,868

### C.3.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy’s approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of operational standards and forms related to pole design, installation and condition assessment. Aurora Energy should maintain the currency and relevancy of these operational document as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant polices.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy’s network assets. Aurora Energy is however presently limited by its asset data availability and quality that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further segment and optimise its asset strategies and expenditure forecasts.

We expect to see an improvement to this situation given the outlined asset strategy (poles maintenance and inspection regime that will provide quality asset data recording opportunity), investment in IT and project management systems, capacity and staff capability building, and harvesting of better quality life cycle asset management information.

### C.3.4 Information provided

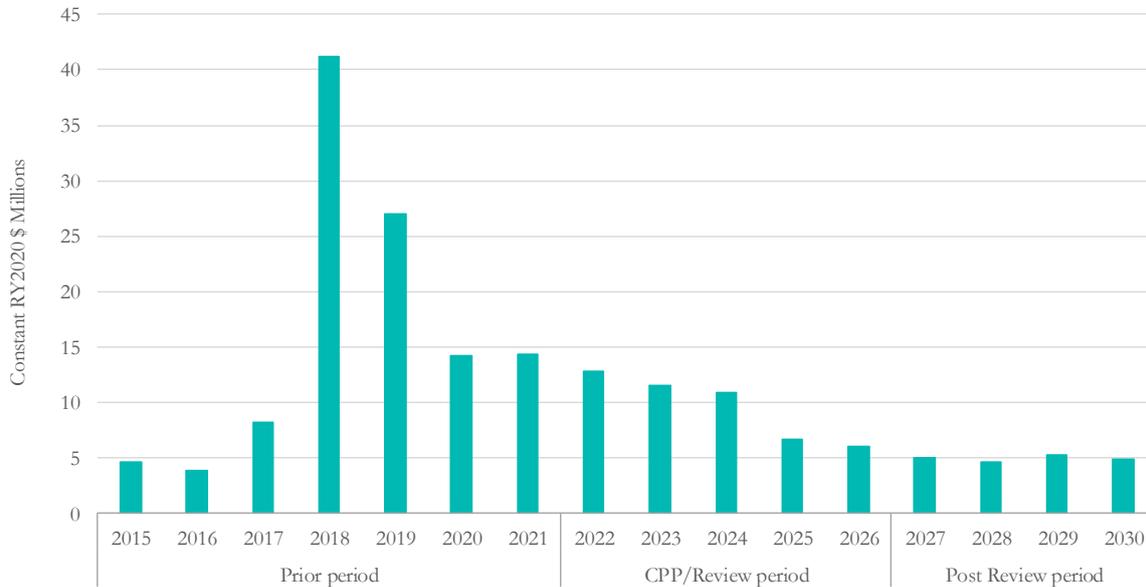
Section D.3.1 presents the information that has been provided by Aurora Energy in relation to the poles renewal program and D.3.2 presents the other information that we have relied on.

### C.3.5 Assessment of forecast method used

#### C.3.5.1 Expenditure trends

Figure C.1 shows the historical and forecast expenditure for the poles replacement program.

Figure C.1: Poles renewal – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

As mentioned above, Aurora Energy delivered a FFTP in 2018 and 2019 which involved replacing an average of 2,000 poles per annum to arrest the increasing and heightened safety risk due to the ageing pole fleet. This expenditure spike was the largest pole replacement program that Aurora Energy has delivered in its history.

The expenditure forecast for 2020 and 2021 is less than the FFTP at approximately \$14 million per annum. The expenditure forecast thereafter during the CPP and review periods gradually starts to decrease from close to \$13 million per annum to a stable average of \$5.5 million in the longer run.

### C.3.5.2 Expenditure justification

Aurora Energy has satisfactorily established the need for these renewals and to complete the current backlog of replacements. The underpinning drivers are appropriately identified, and the assumption used to support the case has been explained. The need is aligned with its risk management framework and asset management principle, and the timing of the need is consistent with the imperative to mitigate the safety risks associated with the aging wood pole population.

For this renewal program we are satisfied that Aurora Energy has assessed the replacement vs. reinforcement options to address the need and the justification provided for opting with a replacement only strategy for the CPP period. However, in our view, it is feasible for Aurora Energy to reinforce some proportion of its wood pole fleet from RY25 onwards during the review period. The argument for this opinion is documented in section D.3, which details our observation of this asset management practice in the industry, clarification provided by Aurora Energy, our response comments and recommendation to the Commission. The unverified amount identified in Table C.2 for the review period pertains to our assessment of the potential to reinstate a pole asset strategy following the CPP period.

Given the inherent need for the service provided by this network infrastructure and the risks involved, we are satisfied that there was no obvious omission in the current strategy for the CPP period.

In order to forecast the expenditure, Aurora Energy uses historical failure rates of poles based on age which also derives the overall fleet asset health assessment. The criticality assessment (proxy for consequence of failure) is considered after establishing the expenditure level and to prioritise actual work.

We are aware of the risk assessment documented in the WSP report (section 8.6, Page 71) where the criticality has been simultaneously considered along with failure probability resulting in a volume of poles categorised in the intolerable risk zones (i.e. maroon and red zones<sup>137</sup>). WSP used a qualitative approach which has been further advanced by Aurora Energy to use historical inspection failure rates which derives a more accurate forecast based on the actual age of each pole within the fleet.

At the same time, we are also aware of the current asset data limitations which was based on historical inspection practices and that newer more accurate methods of testing will offer opportunities to review failure rate data and the possibility of using and refining criticality (consequence) assessments to optimise inspection strategies in the future. This should be achieved by continuing to refine Aurora Energy's current asset strategy (inspection, maintenance, and replacement) that provides such opportunities.

For example, Aurora Energy can identify assets to deploy a tiered asset strategy as follows:

- high failure probability and high failure consequence requiring higher inspection frequency and more earlier replacement criteria
- high failure probability and low failure consequence, or low failure probability and medium consequence using the current inspection regime
- low failure probability and low consequence for relaxed or lower inspection frequency regime (and lower replacement criteria within safety compliance constraints).

Without the simultaneous consideration of both failure probability (proxy by asset health) and failure consequence (proxy by underdeveloped criticality), we believe the current asset strategy has opportunities for advancement to reduce costs when able to be supported by risk assessments, improved performance and condition assessment data.

Further, the need for most of the forecast volume, including renewal backlogs, is driven by safety risk which has the potential to be overstated by actual incidents and other anecdotal information rather than articulated using objective asset failure data (as opposed to failure upon inspection), the potential consequence of those failures, and optimised inspection frequencies. While we do not disagree with the current need for the forecasted renewal volumes, the availability of more advanced asset data would have enabled us to more objectively assess the ALARP position (i.e. cost vs. safety benefit balance) of this renewal proposal.

Given the lack of asset data to accurately assess the criticality profile and to form a view on the reasonableness of the forecast expenditure, we benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is explained in section C.3.5.4.

### C.3.5.3 Key assumptions used

The key data used in forecasting this expenditure is age information. The future wood pole survival curve reflects historical failures on inspection, the only assumption for wood poles is the age of poles where there are data gaps. Currently there is assumed asset life for steel and concrete poles before they are expected to fail inspection tests.

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<sup>137</sup> This risk matrix, the scale used for criticality and failure probability, and the risk appetite or tolerance limit is consistent with Aurora Energy's corporate risk management framework.

These assumptions have been identified in POD01 and its associated model, and are reasonable for this asset fleet. Given the nature of this asset fleet, methodology to forecast expenditure level, data availability, and the variables used for assumption we do not consider conducting sensitivity analysis on these variables is necessary or will add any value to this verification process.

#### C.3.5.4 Benchmarking

The main inputs such as expected asset life and unit cost used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers and are considered reasonable.

We did not benchmark historical performance of this asset fleet with peers directly. We have benchmarked expected life of wood poles and renewal rates with peer businesses in the industry and this review supports the data inputs and outcomes produced by the modelling. A discussion of our comparison of unassisted pole failure per 10,000 poles metrics is presented in Appendix D which indicates Aurora Energy's current failure rate is above industry failure rates but as a result of the program over the CPP and review periods this performance is expected to reduce to an acceptable safety risk level. Our analysis on benchmarking of the annual replacement rates proposed by Aurora Energy against peer businesses within the industry is presented in Appendix D.

Aurora Energy's proposal for this renewal expenditure does not sufficiently detail the risk reduction benefit achieved by the forecast expenditure. The network risk, focusing mostly on the safety aspect, is explained by anecdotal incidents and supported by reference to the WSP report. Apart from reducing the population of aged asset which is represented by improvement in H1 to H5 asset health scoring profile, the benefit is not described or measured in a manner that more directly allows weighing it against the proposed costs.

We have used the unassisted failure rate and replacement rate benchmarking with peers to provide confidence that the level of expenditure is required to meet the safety need and to objectively verify that the ALARP (i.e. cost vs safety benefit) balance has been achieved with the proposed expenditure.

#### C.3.5.5 Contingency factors

No contingency factors have been included in this expenditure forecast.

#### C.3.5.6 Interaction with other forecast expenditures

This is a dedicated pole replacement program. The scope of work in this program also includes replacing the associated crossarms with every pole and a proportion of overhead distribution equipment (switchgear and pole top distribution transformer) based on condition assessment. Therefore, this expenditure should be viewed together with cross-arm and overhead distribution equipment renewal programs.

Similarly, overhead distribution and LV conductor renewal programs incorporates replacing a proportion of poles per km and the cost of this proportion embedded in the re-conductoring unit cost. Some of these would be replaced based on condition (i.e. potentially double counting with this renewal program) and accordingly has been reconciled and adjustments have been appropriately made. The remaining forecast pole replacements are in the modelling forecast.

### C.3.6 Deliverability

Our observations on capex deliverability, in general, have been provided in section 4.5. With regard to pole replacement work, we believe Aurora Energy's recent experience with FTTP has prepared it well for delivering this capital work during the CPP and review periods.

### C.3.7 Our finding

The expenditure forecast for this renewal program is based on the review of the asset replacement modelling and our findings presented in section D.3.9.

### C.3.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

Aurora Energy did not consider wood pole reinforcement in its renewal strategy and forecast. We queried this issue and have presented our observation against each of the clarifications provided by Aurora Energy, and further reasoning for this decision in section D.3.8 in detail.<sup>138</sup> We believe there is potential for Aurora Energy to re-establish the wood pole reinforcement activity from RY25 onwards – which should follow the proposed engineering review and a revisit of a business case during the CPP period. Accordingly, we have estimated an unverified amount during the review period. We recommend the Commission confirm with Aurora Energy its plans for an independent engineering review over the CPP period and revisit the viability of a program with Aurora Energy towards the end of the CPP period

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP period.

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<sup>138</sup> Documented in ‘200516 Pole Reinforcement note’ provided by Aurora Energy on 18 May 2020

## C.4 CROSSARMS RENEWAL (C2)

Table C.4: Verification summary – Crossarms renewal (\$2020, \$millions)

<b>Expenditure category</b>	Crossarms renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$22.9 million Review period: \$38.3 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$22.9 million Review period: \$38.3 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure. We accept the proposed forecast volume based on our assessment of the following factors:</p> <ul style="list-style-type: none"> <li>• asset age information and assumptions</li> <li>• modelling logic and statistical replacement profile</li> <li>• benchmarking with other EDBs to validate the forecast replacement volumes as to whether assumptions could lead to an under or over-estimate in expenditure.</li> </ul>	<p>This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure. Initially we were unsure about the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review. After our draft report, Aurora Energy provided additional cost benchmarking information from other EDBs, an independent consultant review of the bottom-up estimate, and a contractor rate to support its proposed unit cost estimate. Aurora Energy also clarified the work scope (stand-alone crossarms replacement job vs inclusive in pole replacement job) and the associated unit cost. We are now satisfied that the proposed unit cost estimate is consistent with the expenditure objective.</p>
<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We considered WSP’s independent review of network risk and suggested recommendations.</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up and improve asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.</p>	
<b>What needs to be done</b>	NA	
<b>Potential scope for improvement</b>	<ul style="list-style-type: none"> <li>• Aurora Energy should diligently and accurately capture and build-up asset attribute, condition and performance information to enable accurate health and criticality assessment. Aurora Energy should simultaneously</li> </ul>	

consider both failure probability (proxy by asset health) and failure consequence (proxy by criticality) for robust risk assessment thereby refining the expenditure forecast precision and the asset strategy for targeted risk mitigation. This will result in refinement and optimisation of cross-arms asset strategy in the future.

- Further, the business case for safety risk driven expenditure should be better articulated with rich asset attribute, condition and performance data that allows for robust risk assessments. This will also enable objective assessment of ALARP position (i.e. cost vs safety benefit balance).
- Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a line of sight and drive asset management improvements.
- Aurora Energy should actively and regularly benchmark its asset management practices and unit costs where available with peer businesses in the industry with an aim to improve its efficiency.

### C.4.1 Project description

Aurora Energy initiated this renewal program only from 2020. There was no dedicated renewal program for this asset fleet prior to that. Crossarm replacements were previously included within pole renewal, or re-conducting, or reactive works. Aurora Energy is proposing to replace an average of nearly 3,000 crossarms per annum<sup>139</sup> over the CPP and review periods, after which time replacement numbers will gradually reduce approximately 2,100 cross-arms per annum. Renewals are full crossarms assemblies and includes insulators and fittings. The actual replacement work is prioritise based on location criticality assessment.

### C.4.2 Cost estimate / expenditure forecast

Table C.5 shows the forecast expenditure during the CPP and review periods.

Table C.5: Forecast expenditure – crossarms renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	6,563	8,249	8,083	7,829	7,582	22,895	38,306

### C.4.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy’s approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of operational standards and

<sup>139</sup> Replacement being proposed within this renewal program only. Aurora Energy is also proposing to replace cross-arms within other programs such as poles and re-conducting which is outside this renewal program.

forms related to pole design, installation and condition assessment that also describes crossarms. They also refer to AE-ND01-G01 Approved Equipment and Material Schedule document. Aurora Energy should maintain the currency and relevancy of these operational document as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant polices.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy’s network assets. Aurora Energy is however presently limited by its asset data availability and quality for crossarms that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further optimise asset strategies and expenditure forecasts. The status of available data for crossarms is not uncommon for most if not all EDBs in New Zealand and Australia, with all aiming to improve inspection and data collection activities.

We expect to see an improvement to this situation given the outlined asset strategy (crossarms maintenance and inspection regime that will provide quality asset data recording opportunity), investment in IT and project management systems, capacity and staff capability building, and harvesting of better quality life cycle asset management information.

#### C.4.4 Information provided

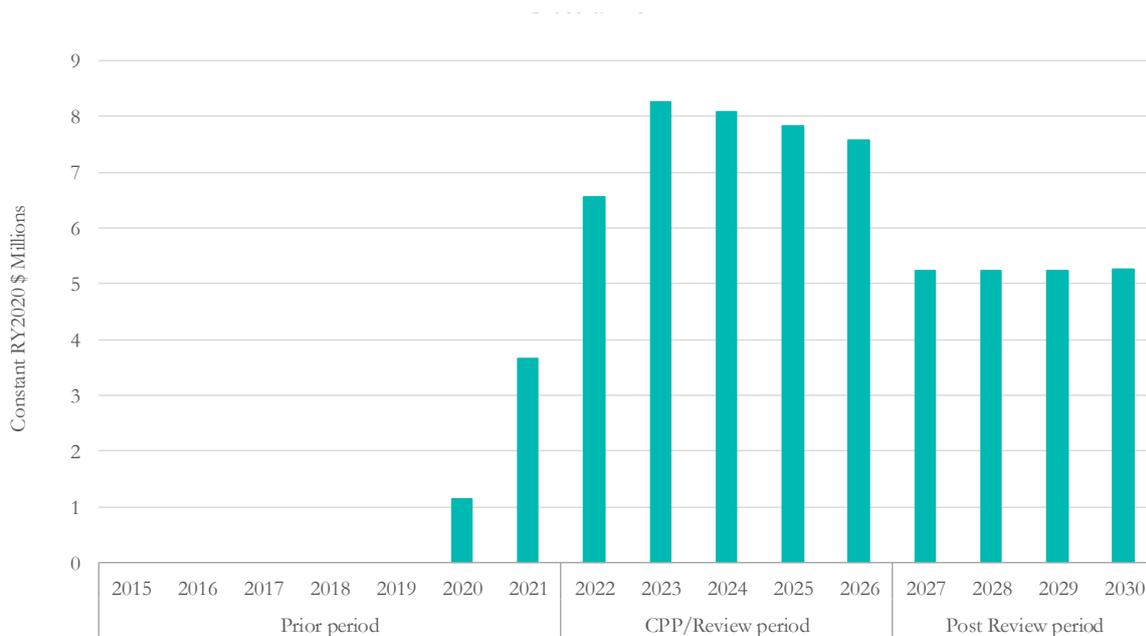
Section D.4.1 presents the information that has been provided by Aurora Energy in relation to the crossarms renewal program and D.4.2 presents the other information that we have relied on.

#### C.4.5 Assessment of forecast method used

##### C.4.5.1 Expenditure trends

Figure C.2 shows the historical and forecast expenditure for the crossarms replacement program.

Figure C.2: Crossarms – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

As mentioned above, Aurora Energy only initiated this dedicated program from RY20. The recent FFTP also involved crossarm replacements even though the FFTP was a dedicated pole renewal program.

The proposed expenditure is forecasted to increase up to \$7.7 million on average per annum and stays at that level during the CPP and review periods. This expenditure is forecast to drop to \$5.2 million per annum in the longer run.

#### C.4.5.2 Expenditure justification

Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning drivers are appropriately identified, the asset condition data limitation described, and the assumption used to support the case has been explained. The need is aligned with its risk management framework and asset management principle, and the timing of the need is consistent with the imperative to mitigate the safety risks associated with the aging cross-arm population.

For this renewal program we are satisfied that Aurora Energy has treated the different type of crossarms accordingly. Given the inherent need for the service provided by the network infrastructure, we are satisfied that there was no obvious omission.

To forecast the expenditure Aurora Energy followed its risk assessment methodology for its volumetric fleet by only considering the asset health assessment (proxy for probability of asset failure). The criticality assessment (proxy for consequence of failure) is considered after establishing the expenditure level and to prioritise actual work. We believe that this assessment approach can result in potentially higher expenditure forecasts with some expenditure that could be deferred if criticality were considered in a risk assessment process. However, this process will also require condition data from future inspections as well as the development of a criticality methodology for crossarms

We are aware of the risk assessment documented in the WSP report (Section 8.6, Pages 71 and 72) where the criticality has been simultaneously considered along with failure probability resulting in a volume of crossarms categorised in the intolerable risk zones (i.e. maroon and red zones<sup>140</sup>). WSP used a qualitative approach that has been further advanced by Aurora Energy to use an age-based replacement model for crossarms. This enables a more accurate forecast based on the same assumptions for the age of crossarms made by WSP

We are also aware of the current asset data limitations and the possibility of refining the health (failure probability) and criticality (consequence) assessments by improving data accuracy and completeness in the future. This should be achieved by continuing with Aurora Energy's current asset strategy (inspection, maintenance and replacement) that provides such opportunities. It is possible that this data improvement and refinement will result in the risk assessment revision from the WSP report. This will enable Aurora Energy to confidently and simultaneously consider the asset health together with criticality for risk assessment to further refine its asset strategy and improve the precision of its expenditure forecast for targeted risk mitigation resulting in expenditure optimisation. For example, Aurora Energy with mature asset management practise can identify assets to deploy tiered asset strategy as follows:

- high failure probability and high failure consequence for an increased inspection frequency and earlier consideration of replacement on condition
- high failure probability and low failure consequence, or low failure probability and high consequence for a routine inspection regime
- low failure probability and low consequence for relaxed or lower inspection frequency regime.

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<sup>140</sup> This risk matrix, the scale used for criticality and failure probability, and the risk appetite or tolerance limit is consistent with Aurora Energy's corporate risk management framework.

The need for most of the forecast volume is based on safety risk and is supported by anecdotal information of actual incidents rather than more definite data on failures followed by risk assessments using criticality in the assessment. If there was more asset condition and performance data available, we could have objectively assessed the ALARP position (i.e. cost vs. safety benefit balance) of this renewal proposal. Insufficient data on crossarms is not uncommon amongst peer organisations.

Given the lack of this data to accurately assess the risks with a criticality to form a view on the reasonableness of the forecast expenditure, we benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is explained in Section C.4.5.4.

### C.4.5.3 Key assumptions used

The key assumptions used in forecasting this expenditure are the age information using the age of poles and associated overhead equipment as a proxy and a statistical distribution of replacement behaviour and the remaining age as the proxy for asset health and probability of failure. These assumptions have been identified in POD02 and its associated model – and are reasonable for this asset fleet.

Given the nature of this asset fleet, methodology to forecast expenditure level, data availability, and the variables used for assumption we do not consider conducting sensitivity analysis on these variables is necessary or will add any value to this verification process.

### C.4.5.4 Benchmarking

The main inputs such as unit cost and expected asset life used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers.

Initially we were unsure whether the unit cost input for crossarms was inefficient or otherwise inconsistent with the information contained within Jacobs' independent review of Aurora Energy's pricebook. The proposed unit cost also appeared inconsistent with the rate used when estimating the ACE level for the respective FSA contractors. After our draft report, Aurora Energy provided the following additional cost information in support of its proposed unit cost input:

- survey of crossarm unit cost information from nine New Zealand EDBs and close examination of their scope of work for similarities – i.e. standalone replacement jobs, geography, reactive / proactive / opportunistic practice – to consider or benchmark against the most matching information
- an independent review of Aurora Energy's bottom up unit cost estimate for standalone crossarm replacement jobs that incorporates associated overhead costs
- commercial rates for this work in the central region from external contractor.

Aurora Energy also provided an updated pricebook and explained its version history utilised in the estimation of the ACE level for the respective FSA contractor and its updates. Aurora Energy clarified the nature, scope and logistics associated with its proposed standalone crossarm replacement jobs – as compared to jobs inclusive of pole replacement and how the crossarm unit cost derived from such jobs are materially lower than standalone jobs.

Based on this information, we are now satisfied that the proposed unit cost estimate is consistent with the nature of the replacement job and is not unreasonable.

We could not benchmark historical performance of this asset fleet with peers directly. We have benchmarked the expected asset life assumption for wood crossarms and steel crossarms and consider them to be reasonable. Our analysis on benchmarking of the annual replacement rates proposed by Aurora Energy against peer businesses within the industry is presented in Appendix D. In summary our analysis suggests that even though Aurora Energy's annual replacement rate is higher than the compared businesses annual replacement rate, we accept this higher volume in the CPP and review periods as other

businesses have had programs in place earlier and Aurora Energy needs to manage the bow-wave of replacement expenditure for this asset fleet. It will also allow Aurora Energy to collect, revise and build-up the asset data on actual attributes, performance and condition as it progresses with its asset strategy.

Aurora Energy's proposal for this renewal expenditure does not sufficiently detail the risk reduction benefit achieved by the forecast expenditure. The network risk, focusing mostly on the safety aspect, is explained by anecdotal incidents and supported by reference to the WSP report. Apart from reducing the population of aged asset which is represented by improvement in H1 to H5 asset health scoring profile, the benefit is not described or measured in a manner that more directly allows weighing it against the proposed costs.

We have used the annual replacement rate benchmarking with peers to form a view that the proposed level of expenditure is required to meet the safety need and to objectively verify that the ALARP (i.e. cost vs safety benefit) balance has been achieved with the proposed expenditure.

#### **C.4.5.5 Contingency factors**

No contingency factors have been included in this expenditure forecast.

#### **C.4.5.6 Interaction with other forecast expenditures**

This is a newly initiated dedicated crossarms replacement program. The scope of work in this program also includes replacing the associated materials (insulators, fittings etc.) in the crossarms.

Separately, the poles renewal program incorporates replacing 1.7 crossarms per pole and the cost is embedded within the pole unit cost. Also, the overhead distribution and LV conductor renewal programs incorporate replacing a proportion of crossarms per km of re-conductoring and including the cost of this proportion in the re-conductoring unit cost. Some of these would be replaced based on condition (i.e. potentially double counting with this renewal program) and accordingly all programs have been reconciled and adjustments have been appropriately made. The remaining forecast crossarms replacements are in the modelling forecast.

#### **C.4.6 Deliverability**

Our observations on capex deliverability, in general, have been provided in section 4.5. With regard to crossarms replacement work, we believe Aurora Energy's recent experience with FTTP has prepared it well for delivering this capital work during the CPP and review periods.

#### **C.4.7 Our finding**

The expenditure forecast for this renewal program is based on the review of the asset replacement modelling and our findings presented in section D.4.9.

#### **C.4.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP and review periods.

## C.5 OVERHEAD DISTRIBUTION CONDUCTORS RENEWAL (C3)

Table C.6: Verification summary – Overhead distribution conductors renewal (\$2020, \$millions)

<b>Expenditure category</b>	Distribution conductors renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$16.2 million Review period: \$28.1 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$16.2 million Review period: \$28.1 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure.  We accept the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review  We accept the proposed forecast volume based on our assessment of the following factors: <ul style="list-style-type: none"> <li>• asset age information and assumptions</li> <li>• modelling logic and statistical replacement profile</li> <li>• benchmarking with other EDBs to validate the forecast replacement volumes as to whether assumptions could lead to an under or over estimate in expenditure.</li> </ul>	We examined all the inputs that determines the forecast expenditure.  We are satisfied with the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review.
<b>Other relevant criteria from ToR</b>	We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We considered WSP’s independent review of network risk and suggested recommendations.  We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up and improve asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.	
<b>What needs to be done</b>	NA	
<b>Potential scope for improvement</b>	<ul style="list-style-type: none"> <li>• Aurora Energy should diligently and accurately capture and build-up asset attribute, condition and performance information to enable accurate asset health and criticality assessment. Aurora Energy should simultaneously consider both failure probability (proxy by asset health) and failure consequence (proxy by criticality) for robust risk assessment</li> </ul>	

thereby refining the expenditure forecast precision and the asset strategy for targeted risk mitigation. This will result in refinement and optimisation of overhead distribution conductor asset strategy in the future.

- Further, the business case for safety risk driven expenditure should be better articulated with rich asset attribute, condition and performance data that allows for robust risk assessments. This will also enable objective assessment of ALARP position (i.e. cost vs safety benefit balance).
- Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements.

### C.5.1 Project description

Aurora Energy initiated this renewal program only from RY20. There was no dedicated renewal program for this asset fleet prior to that. Overhead distribution conductors replacements were included within reactive work, overhead distribution equipment renewal or entire feeder replacement projects, and generally were low in volume prior to 2020. Aurora Energy is proposing to replace an average of 28 circuit km of distribution conductor and an average of 40 under-clearance spans per annum over the CPP period, after which time replacement will be an average of 32 circuit km per annum. Renewals also includes a proportion of poles and corresponding crossarms in a km of re-conductoring (i.e. it is assumed that some proportion of the existing poles and cross-arms will be reused during the re-conductoring work). The actual replacement work is prioritise based on location criticality assessment.

### C.5.2 Cost estimate / expenditure forecast

Table C.7 shows the forecast expenditure during the CPP and review periods.

Table C.7: Forecast expenditure – overhead distribution conductor renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	4,692	5,538	5,969	6,134	5,727	16,199	28,059

### C.5.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of operational standards and forms related to overhead line design, construction and inspection. Aurora Energy should maintain the currency and relevancy of these operational documents as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant polices.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy’s network assets. Aurora Energy is however presently limited by its asset data availability and quality that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further optimise asset strategies and expenditure forecasts.

We expect to see an improvement to this situation given the outlined asset strategy (overhead distribution conductor inspection regime that will provide quality asset data recording opportunity), investment in IT and project management systems, capacity and staff capability building, and harvesting of better quality life cycle asset management information.

### C.5.4 Information provided

Section D.5.1 presents the information that has been provided by Aurora Energy in relation to the distribution conductors renewal program and D.5.2 presents the other information that we have relied on.

### C.5.5 Assessment of forecast method used

#### C.5.5.1 Expenditure trends

Figure C.3 shows the historical and forecast expenditure for the overhead distribution conductor replacement program.

Figure C.3: Overhead distribution conductor – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

As mentioned above, Aurora Energy did not have a dedicated overhead distribution conductor renewal program and has only initiated this dedicated program from RY20. The proposed expenditure in the near future is forecast to increase and will be an average of \$5.4 million per annum over the CPP period, and \$5.6 million per annum over the review period. This expenditure is forecast to drop to \$4.4 million on average per annum from RY27 to RY30.

### C.5.5.2 Expenditure justification

Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning drivers are appropriately identified, the asset condition data limitation described, and the assumption used to support the case has been explained. The need is generally aligned with its risk management framework and asset management principle. The timing of the need is also generally consistent with the imperative to mitigate the safety risks associated with the aging conductor and under clearance span population.

For this renewal program we are satisfied that Aurora Energy has treated the different type of conductors accordingly. Given the inherent need for the service provided by the network infrastructure, we are satisfied that there was no obvious omission.

To forecast the expenditure Aurora Energy followed its risk assessment methodology for its volumetric fleet by only considering the asset health assessment (proxy for probability of asset failure). The criticality assessment (proxy for consequence of failure) is considered after establishing the expenditure level and to prioritise actual work. We believe that this risk assessment approach tends to result in potentially higher expenditure forecasts with some expenditure that could be deferred if criticality were considered in a risk assessment process. However, this process will also require condition data from future inspections and sample testing of replaced conductors, as well as the development of a criticality methodology for conductors

We are aware of the risk assessment documented in the WSP report (Section 12.6, Page 115) where the criticality has been simultaneously considered along with failure probability resulting in lower volume of overhead distribution conductor categorised in the intolerable risk zones (i.e. maroon and red zones<sup>141</sup>) which should have informed the replacement forecast. WSP used a qualitative approach that has been further advanced by Aurora Energy to use an age-based replacement model for conductors – which enables a more accurate forecast based on the same assumptions for the age of conductors made by WSP.

At the same time, we are also aware of the current asset data limitations and the possibility of refining the health (failure probability) and criticality (consequence) assessments by improving data accuracy and completeness in the future. This should be achieved by continuing with Aurora Energy's current asset strategy (inspection, maintenance and replacement) that provide such opportunities. It is possible that this data improvement and refinement will result in the risk assessment revision from the WSP report. This will enable Aurora Energy to confidently and simultaneously consider the asset health together with criticality for risk assessment to further refine its asset strategy and improve the precision of its expenditure forecast for targeted risk mitigation resulting in expenditure optimisation.

For example, Aurora Energy with mature asset management practise can identify assets to deploy tiered asset strategy as follows:

- high failure probability and high failure consequence for earlier consideration of replacement on expected condition with sample testing
- high failure probability and low failure consequence, or low failure probability and high consequence for a replacement based on expected life and sample testing
- low failure probability and low consequence for relaxed or lower inspection frequency regime.

The need for the forecast volume is based on safety risk and is supported by anecdotal incidents only rather than more definite data on failures followed by risk assessments using criticality in the assessment.

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<sup>141</sup> This risk matrix, the scale used for criticality and failure probability, and the risk appetite or tolerance limit is consistent with Aurora Energy's corporate risk management framework.

Better access to asset condition data would have enabled us to objectively assess the ALARP position (i.e. cost vs. safety benefit balance) of this renewal proposal.

Given the lack of asset data to accurately assess the criticality profile and to form a view on the reasonableness of the forecast expenditure, we benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is explained in section D.5.4.

### C.5.5.3 Key assumptions used

The key assumptions used in forecasting this expenditure are the age information and expected life of the different conductors under different corrosion conditions (the age where there were data gaps), a statistical distribution around an expected life, and using the remaining age as the proxy for asset health or probability of failure. These assumptions have been identified in POD04 and its associated model which we consider, are reasonable for this asset fleet.

Given the nature of this asset fleet, the methodology to forecast expenditure level, data availability, and the variables used we do not consider conducting sensitivity analysis on these variables is necessary or will add any value to this verification process.

### C.5.5.4 Benchmarking

The main inputs such as unit cost and expected asset life used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers which we consider are reasonable.

We did not benchmark historical performance of this asset fleet with peers directly due to the limitation of available performance data. Our analysis on benchmarking of the annual replacement rates proposed by Aurora Energy against peer businesses within the industry is presented in Appendix D. In summary our analysis suggests that Aurora Energy's annual replacement rate is higher than the compared businesses annual replacement rate as many other businesses have begun conductor replacement programs earlier than Aurora Energy. We accept this aggressive volume in the CPP and review periods to prevent the bow-wave of replacement expenditure for this asset fleet in the future. It will also allow Aurora Energy to collect, revise and build-up the asset data on actual attributes, performance and condition as it progresses with its asset strategy.

Aurora Energy's proposal for this renewal expenditure does not sufficiently detail the risk reduction benefit achieved by the forecast expenditure. The network risk, focusing mostly on the safety aspect, is explained by anecdotal incidents and supported by reference to the WSP report. Apart from reducing the population of aged asset which is represented by improvement in H1 to H5 asset health scoring profile, the benefit is not described or measured in a manner that more directly allows weighing it against the proposed costs.

We have used the annual replacement rate benchmarking with peers to form a view that the proposed level of expenditure is required to meet the safety need and to objectively verify that the ALARP (i.e. cost vs safety benefit) balance has been achieved with the proposed expenditure.

### C.5.5.5 Contingency factors

No contingency factors have been included in this expenditure forecast.

### C.5.5.6 Interaction with other forecast expenditures

This is a newly initiated dedicated overhead distribution conductor replacement program. The scope of work in this program also includes replacing a proportion of poles and crossarms in a circuit km while re-

conducting based on condition assessment. Therefore, this expenditure should be viewed together with the poles and crossarms renewal programs. To address the potential for double counting of poles and crossarms between these renewal programs, the forecast quantities have been accordingly reconciled between the programs and adjustments have been appropriately made to the forecast.

### **C.5.6 Deliverability**

Our observations on capex deliverability, in general, have been provided in section 4.5. The overhead distribution conductor replacement work will most likely be packaged within the ACE level for respective FSA contractor. The selection of the FSA contractors based on their capacity and capability and in response to the proposed expenditure in the AMP 2018-28 should allow delivering this capital work during the CPP and review periods.

### **C.5.7 Our finding**

The expenditure forecast for this renewal program based on the review of the asset replacement modelling and our findings presented in section D.5.9.

### **C.5.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1 the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP period.

## C.6 OVERHEAD LV CONDUCTORS RENEWAL (C4)

Table C.8: Verification summary – Overhead LV conductors renewal (\$2020, \$millions)

<b>Expenditure category</b>	Overhead LV conductors renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$10.6 million Review period: \$19.6 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$10.6 million Review period: \$19.6 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure.</p> <p>We accept the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review</p> <p>We accept the proposed forecast volume based on our assessment of the following factors:</p> <ul style="list-style-type: none"> <li>• asset age information and assumptions</li> <li>• modelling logic and statistical replacement profile</li> <li>• benchmarking with other EDBs to validate the forecast replacement volumes as to whether assumptions could lead to an under or over estimate in expenditure.</li> </ul>	<p>We examined all the inputs that determines the forecast expenditure.</p> <p>We accept the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review.</p>
<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We considered WSP’s independent review of network risk and suggested recommendations.</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up and improve asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.</p>	
<b>What needs to be done</b>	NA	NA

### Potential scope for improvement

- Aurora Energy should diligently and accurately capture and build-up asset attribute, condition and performance information to enable accurate asset health and criticality assessment. Aurora Energy should simultaneously consider both failure probability (proxy by asset health) and failure consequence (proxy by criticality) for robust risk assessment thereby refining the expenditure forecast precision and the asset strategy for targeted risk mitigation. This will result in refinement and optimisation of overhead LV conductor asset strategy in the future.
- Further, the business case for safety risk driven expenditure should be better articulated with rich asset attribute, condition and performance data that allows for robust risk assessments. This will also enable objective assessment of ALARP position (i.e. cost vs safety benefit balance).
- Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements.

## C.6.1 Project description

There has been no historical dedicated or standalone overhead LV conductor renewal program. Aurora Energy proposes to initiate this renewal program from 2022. Overhead LV conductor replacements were included within reactive work, overhead distribution equipment renewal or entire feeder replacement projects, and generally have been very low or negligible in volume in the past. Aurora Energy is proposing to replace an average of 28 circuit km of LV conductor over the CPP period, after which time replacement will be an average of 30 circuit km per annum. Renewals also includes a proportion of poles and corresponding cross-arms in a km of re-conductoring (i.e. it is assumed that some proportion of the existing poles and cross-arms will be reused during the re-conductoring work). The actual replacement work is prioritised based on location criticality assessment.

## C.6.2 Cost estimate / expenditure forecast

Table C.9 shows the forecast expenditure during review and the CPP periods.

Table C.9: Forecast expenditure – overhead LV conductor renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	2,268	4,108	4,271	4,523	4,460	10,647	19,631

## C.6.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of operational standards and

forms related to overhead line design, construction and inspection. Aurora Energy should maintain the currency and relevancy of these operational document as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant polices.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy’s network assets. Aurora Energy is however presently limited by its asset data availability and quality that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further optimise asset strategies and expenditure forecasts.

We expect to see an improvement to this situation given the outlined asset strategy (overhead LV conductor inspection regime that will provide quality asset data recording opportunity), investment in IT and project management systems, capacity and staff capability building, and harvesting of better quality life cycle asset management information.

### C.6.4 Information provided

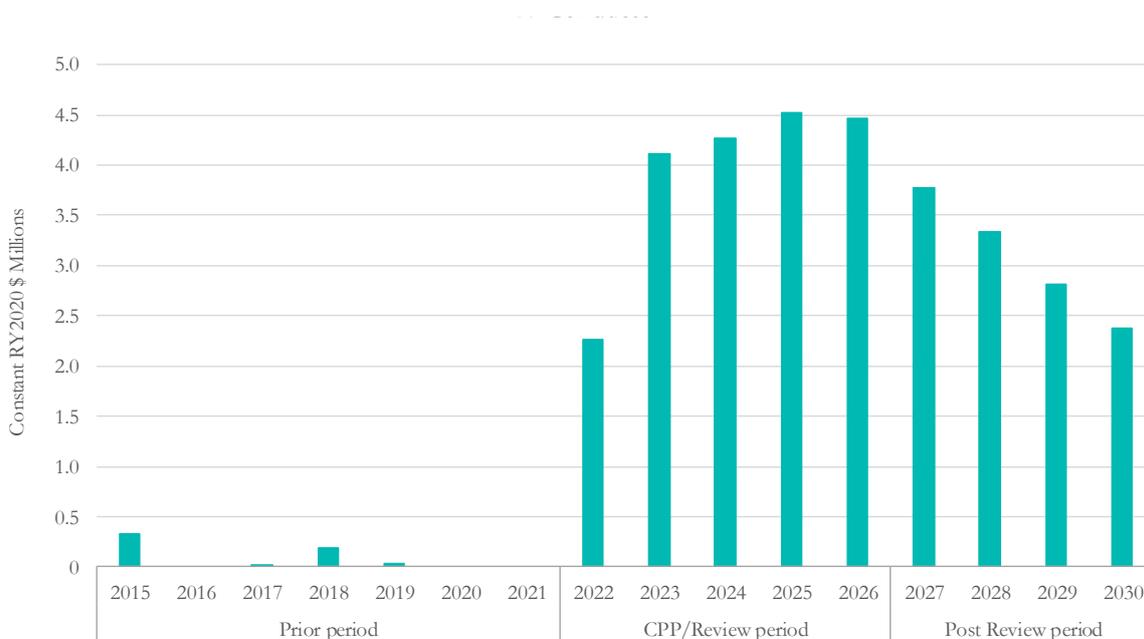
Section D.6.1 presents the information that has been provided by Aurora Energy in relation to the overhead LV conductors renewal program and D.6.2 presents the other information that we have relied on.

### C.6.5 Assessment of forecast method used

#### C.6.5.1 Expenditure trends

Figure C.4 shows the historical and forecast expenditure for the overhead LV conductor replacement program.

Figure C.4: Overhead LV conductor – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Historically, Aurora Energy never had a dedicated or a standalone overhead LV conductor renewal program. Aurora Energy proposes to initiate this dedicated renewal program from RY22. The proposed

expenditure is forecast to increase and will be an average of \$3.5 million per annum during the CPP period, and \$3.9 million per annum during the review period. This expenditure is forecast to first increase and then gradually drop to an average of \$3.1 million per annum over RY27 to RY30.

### C.6.5.2 Expenditure justification

Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning drivers are appropriately identified, the asset data limitation described, and the assumption used to support the case has been explained. The need is generally aligned with its risk management framework and asset management principle. The timing of the need is also generally consistent with the imperative to mitigate the safety risks associated with the aging conductor population.

For this renewal program we are satisfied that Aurora Energy has treated the different type of conductors accordingly. Given the inherent need for the service provided by the network infrastructure, we are satisfied that there was no obvious omission.

To forecast the expenditure Aurora Energy followed its risk assessment methodology for its volumetric fleet by only considering the asset health assessment (proxy for probability of asset failure). The criticality assessment (proxy for consequence of failure) is considered after establishing the expenditure level and to prioritise actual work. We believe that this assessment approach tends to give potentially higher expenditure forecasts with some expenditure that could be deferred if criticality was considered in a risk assessment process. However, this process will also require condition data from future inspections and sample testing of replaced conductors, as well as the development of a criticality methodology for conductors

The modelling approach and asset strategy is the same as for distribution conductors including with respect to:

- the limitations of condition data and ability to conduct formal risk assessments
- consideration of WSP's findings (section 12.6, page 115 of its report).

As per the distribution conductor fleet, better access to asset condition data would have enabled us to objectively assess the ALARP position (i.e. cost vs. safety benefit balance) of this renewal proposal. Given the lack of asset data to accurately assess the criticality profile and to form a view on the reasonableness of the forecast expenditure, we benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is explained in section D.6.4.

### C.6.5.3 Key assumptions used

The key assumptions used in forecasting this expenditure are the age information and expected life of the different conductors under different corrosion conditions (the age where there were data gaps), a statistical distribution around an expected life, and using the remaining age as the proxy for asset health or probability of failure. These assumptions have been identified in POD05 and its associated model, and are reasonable for this asset fleet.

Given the nature of this asset fleet, the methodology to forecast expenditure level, data availability, and the variables used we do not consider conducting sensitivity analysis on these variables is necessary or will add any value to this verification process.

#### C.6.5.4 Benchmarking

The main inputs such as unit cost and expected asset life used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers which we consider are reasonable.

We did not benchmark historical performance of this asset fleet with peers directly due to the limitation of available performance data. Our analysis on benchmarking of the annual replacement rates proposed by Aurora Energy against peer businesses within the industry is presented in Appendix D. In summary our analysis suggests that even though Aurora Energy's annual replacement rate is higher than the compared businesses annual replacement as most have had replacement programs in place for several years. We accept this aggressive volume in the CPP and review periods to manage the bow-wave of replacement expenditure for this asset fleet in the future. It will also allow Aurora Energy to collect, revise and build-up the asset data on actual attributes, performance and condition as it progresses with its asset strategy.

Aurora Energy's proposal for this renewal expenditure does not sufficiently detail the risk reduction benefit achieved by the forecast expenditure. The network risk, focusing mostly on the safety aspect, is explained by anecdotal incidents and supported by reference to the WSP report. Apart from reducing the population of aged asset which is represented by improvement in H1 to H5 asset health scoring profile, the benefit is not described or measured in a manner that more directly allows weighing it against the proposed costs.

We have used the annual replacement rate benchmarking with peers to form a view that the proposed level of expenditure is required to meet the safety need and to objectively verify that the ALARP (i.e. cost vs safety benefit) balance has been achieved with the proposed expenditure.

#### C.6.5.5 Contingency factors

No contingency factors have been included in this expenditure forecast.

#### C.6.5.6 Interaction with other forecast expenditures

This will be a new dedicated overhead LV conductor replacement program. The scope of work in this program also includes replacing a proportion of poles and cross-arms in a circuit km while re-conductoring based on condition assessment. Therefore, this expenditure should be viewed together with poles and cross-arm renewal programs. To address the potential for double counting of poles and cross-arms between these renewal programs, the forecast quantities have been accordingly reconciled and adjustment have been appropriately made to the forecast.

### C.6.6 Deliverability

Our observation on capex deliverability, in general, have been provided in section 4.5. The overhead LV conductor replacement work will most likely be packaged within the ACE level for respective FSA contractor. The selection of the FSA contractors based on their capacity and capability and in response to the proposed expenditure in the AMP 2018-28 should allow delivering this capital work during the review period.

### C.6.7 Our finding

The expenditure forecast for this renewal program is based on the review of the asset replacement modelling and our findings presented in section D.6.9.

### **C.6.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP period.

## C.7 ZONE SUBSTATION RENEWALS (C5)

The zone substation portfolio forecast consists of five fleets:

- **power transformers** – power transformers, bunding, oil containment, firewalls and neutral earthing transformers
- **indoor switchgear** – 6.6 to 33 kV indoor switchgear within zone substation buildings
- **buildings and grounds** – buildings that house indoor switchgear and secondary systems equipment; it also includes fences, access ways, security and switchyard earthing
- **outdoor switchgear** – circuit breakers, air-break switches and reclosers located in outdoor switchyards
- **ancillary zone sub equipment** – mobile zone substation, load management and shunt capacitor equipment.

Power transformers, outdoor and indoor switchgear have been assessed separately in sections C.8, C.9 and C.10 respectively. This section provides a review of the other assets within the zone substation portfolio and overall a review of the coordination or renewal requirements into zone substation projects and the expenditure outcome.

Table C.10: Verification summary – Zone substation renewals (\$2020, \$millions)

Expenditure category	Zone substation building renewal program	
Aurora Energy CPP forecast	The buildings cost component is embedded within the overall zone substation category, which is as follows: CPP period: \$26.5 million Review period: \$41.9 million	
Recommendation	<b>Verified</b> CPP period: \$26.5 million Review period: \$41.9 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
Expenditure outcome assessment	<b>Buildings, grounds and ancillary equipment:</b> We examined all the inputs that determine the building cost component estimate embedded within the overall zone substation forecast expenditure We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the building cost component. We accept the quantities used to build-up the building cost component. We accept the drivers and the reasoning provided to include the building works in the overall scope of zone substation renewal work for every proposed site.	We examined all the inputs that determine the building cost component estimate embedded within the overall zone substation forecast expenditure. We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the building cost component.

<b>Other relevant criteria from ToR</b>	We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down, via the direction set by the AMP 2018-28, to developing the zone substation renewal plan in general. We note a lower level of focus on building and civil infrastructure assets relative to electrical infrastructure in the asset strategy.
<b>What needs to be done</b>	NA
<b>Potential scope for improvement</b>	<b>Buildings and grounds:</b> Aurora Energy should continue efforts to accurately capture and build-up asset attribute and condition data to enable accurate health and criticality assessment of its zone substation building and civil infrastructure also. Focus should be given to HVAC system, roofs, ceilings, structural water ingress, earthing, fencing, security set-up and oil containment system. Such information should be used in risk assessment and implementing prudent asset strategies.

### C.7.1 Project description

**Zone substation projects:** For the review period, Aurora Energy has proposed to replace 11 power transformers based on its risk assessment and coordination planning of forecast zone substation together with other discretely identified renewal and growth works in the same site.

Aurora Energy has proposed to replace six indoor switchboards (consisting of 88 circuit breakers) and replace 35 outdoor switches and 26 outdoor circuit breakers and reclosers over the review period.

Expenditure on zone substation assets was very low prior to RY18, after which significant increases in portfolio expenditure occurred with the replacement of the Neville Street zone substation and the associated 33 kV supply cables (new Carisbrook zone substation).

The renewal works have been bundled into the following zone substation capital projects over the review period:

- Alexandra 33 kV outdoor-indoor conversion
- Andersons Bay substation rebuild
- Queenstown 33 kV outdoor switchyard renewal
- Roxburgh 33 kV outdoor switchyard renewal
- Green Island substation rebuild
- Port Chalmers transformer replacement
- Arrowsmith transformer and outdoor 11 kV switchgear replacement
- Halfway Bush 11 kV switchboard replacement
- Clyde-Earnsclough substation rebuild
- Smith Street 11 kV switchboard replacement
- Lauder Flat transformer replacement
- Dalefield substation rebuild
- Mosgiel transformer replacement and 33 kV outdoor-indoor conversion.

The project scope related to power transformers, indoor and outdoor switchgear are addressed in the following sections C.8, C.9 and C.10.

**Buildings, grounds and ancillary equipment:** In recent years Aurora Energy has undertaken civil and building works at its zone substation sites to provide seismic reinforcements, upgrade fire and security system, and asbestos remediation. These are presently ongoing works and Aurora Energy has stated that the work is based on the recommendations of an independent risk assessment of civil infrastructure assets in the zone substation conducted in 2015.

For the CPP and review periods, Aurora Energy has proposed upgrade and new building works. These proposed building renewal works are primarily driven by lack of space in the existing buildings (i.e. in three sites). Secondary drivers for renewal are condition and seismic risk. Lastly, building works have been included in the overall scope of zone substation renewal work to utilise the opportunity to rebuild the buildings to modern day standards.

### C.7.2 Cost estimate / expenditure forecast

**Zone substation projects:** Table C.11 shows the forecast expenditure during the CPP and review periods for the overall zone substation renewal project work.

Table C.11: Forecast expenditure – overall zone substation renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	10,495	5,774	10,256	10,435	4,987	26,525	41,947

**Buildings, grounds and ancillary equipment:** The building work costs constitute only a part of the overall zone substation expenditure forecast. Not all the zone substations proposed for renewal includes building works. The scopes of building works are specific and varies in each zone substation that it is included.

The costs allocated to building component within the zone substation expenditure forecast is based on customised estimate for each zone substation site renewal work using the building block from the pricebook. The building cost component is a site-specific estimate build-up.

The majority of building works are proposed for Andersons Bay, Green Island, Clyde-Earnsclough, Alexandra and Mosgiel zone substations.

### C.7.3 Relevant policies and planning standards

**Zone substation projects:** Relevant policies and planning standards related to power transformers, indoor and outdoor switchgear are addressed in the following sections C.8, C.9 and C.10.

**Buildings, grounds and ancillary equipment:** Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy’s approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps.

We reviewed several operational standards and forms related to zone substation maintenance and inspection activities. Aurora Energy should maintain the currency and relevancy of these operational

documents as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant policies.

Aurora Energy’s asset management plan and strategy related to zone substation building and civil infrastructure does not provide focus and operational direction with similar detail as it does for its electrical infrastructure. We note that such practice is not uncommon within the industry.

### C.7.4 Information provided

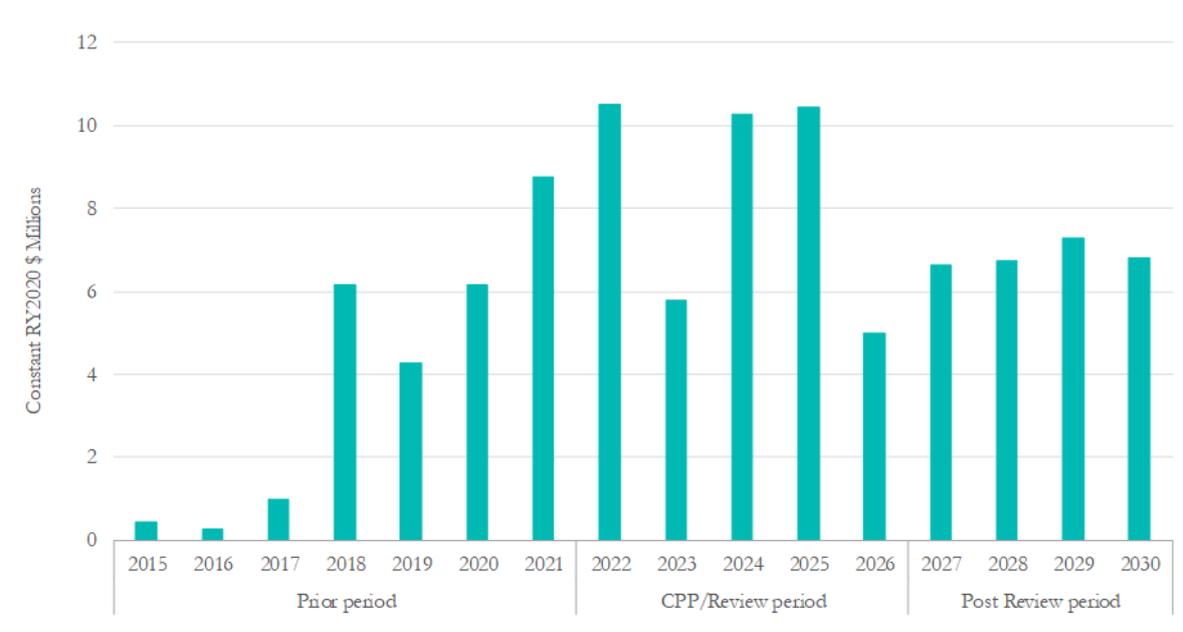
Section D.7.2 presents the information that has been provided by Aurora Energy in relation to the zone substation building renewal program and D.7.3 presents the other information that we have relied on.

### C.7.5 Assessment of forecast method used

#### C.7.5.1 Expenditure trends

**Zone substation projects:** Figure C.5 shows the historical and forecast expenditure for the overall zone substation renewal program.

Figure C.5: Overall zone substation renewals – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

**Buildings, grounds and ancillary equipment:** During RY15 to RY17, Aurora Energy spent little capital on renewing its zone substation building and civil infrastructure. From RY18 onwards the expenditure on building works has mostly been driven by the recommendations from the independent RY15 risk assessment report.

As mentioned earlier, the building work costs constitute only a part of the overall zone substation expenditure forecast. In other words, the building cost component is embedded within the forecast shown in the figure above. Also, the scopes of building works are specific and vary in each zone substation, and in some sites the renewal scope does not include any building works.

### C.7.5.2 Expenditure justification

**Zone substation projects:** Aurora Energy has used a separate tool, the coordination tool, to review the entire portfolio of asset replacements in the zone substation portfolio to develop optimised project timing.

The coordination tool aims to ensure:

- equipment is replaced in a coordinated manner so that all replacements occurring in the five-year period are bundled into a single project along with consideration of growth project requirements over the period
- renewal (and growth) projects are programmed to occur in an orderly manner and the overall program of work is deliverable.

Customised cost estimates have been prepared for each of the asset renewal projects by reviewing the existing configuration/layout of the relevant zone substation, determining whether like-for-like replacement is a sensible/optimal approach (i.e. via options analysis) and using the price-book to determine the total customised cost estimate in the light of other similar project costs.

Following discussions with Aurora Energy regarding the prioritisation of two 11 kV switchboards, Aurora Energy updated the zone substation program (MOD09), which addressed the matters raised and Aurora Energy also considered the impact of the changes to move other projects to address deliverability adjustments.

Aurora Energy has reviewed the timing of some growth-related major projects as a result of early COVID-19 impact assessments. The need to re-evaluate renewal needs covered by growth projects and the above changes resulted in a small increase to the zone substation forecast over the CPP and review periods.

**Buildings, grounds and ancillary equipment:** Aurora Energy has satisfactorily established the need for the inclusion of building works in the overall zone substation renewal program. Where building works are included in the project scope, the underpinning drivers are appropriately identified and explained. The need is aligned with its risk management framework and asset management principle. The timing of the need is consistent with prudent forecast work planning that considers bundling of discrete scope of works separately identified in the same site, resourcing and risk.

Aurora Energy's building work forecast expenditure is mainly driven by one or the combination of the following factors:

- recommendations from the independent 2015 risk assessment report targeting buildings for reinforcement to meet the New Building Standard (NBS) for an Importance Level 4 (IL4) standard
- lack of space in the existing building when other asset fleets in the site undergoes renewal
- utilising the opportunity to be included with other replacement scope of work in the same site to mitigate risk in proactive manner.

Therefore, in order to forecast the expenditure for the zone substation building works Aurora Energy did not directly follow the usual risk management methodology (asset health assessment × criticality assessment). We consider Aurora Energy's approach to identify zone substation building work during the review CPP and periods to be reasonable.

For this renewal program we are satisfied that Aurora Energy has assessed various feasible options (consisting of various asset fleets including building work in the project scope) to address the need (including consideration of decommissioning of the site and non-network solutions). Each option was tested against the following criteria:

- meeting safety requirements

- meeting business need
- cost effective
- practicality of implementation
- alignment with good industry practice
- alignment with other planned works
- strategic fit.

Options were shortlisted and a preferred one selected for each zone substation renewal work. The estimate of the preferred option was then further refined using the pricebook building block cost information and the scope of work included in the preferred option. Aurora Energy has assumed two years duration to undertake each proposed zone substation renewal project with 30% expended in the first year and the remaining 70% expended in the second year.

In order to develop Aurora Energy's asset management plan and strategy related to zone substation building and civil infrastructure, Aurora Energy should capture and build-up asset attribute and condition data. This will enable robust risk assessment and help in identifying forecast expenditure (and justification) for this civil asset fleet. Focus should be given to HVAC system, roofs, ceilings, structural water ingress, earthing, fencing, security set-up and oil containment system.

#### C.7.5.3 Key assumptions used

**Zone substation projects:** Key assumptions related to power transformers, indoor and outdoor switchgear are addressed in the following sections C.8, C.9 and C.10.

**Buildings, ground and ancillary equipment:** Given the nature of this civil asset fleet, the volume of work being proposed, and the approach adopted by Aurora Energy to identify building works and proposing them in the zone substation expenditure forecast (as explained earlier), each proposed building work has assumptions underpinning the customised cost estimates. We have assessed the cost estimation in the following benchmarking section.

#### C.7.5.4 Benchmarking

**Zone substation projects:** Benchmarking related to power transformers, indoor and outdoor switchgear are addressed in the following sections C.8, C.9 and C.10.

**Buildings, grounds and ancillary equipment:** The unit cost for zone substation building categories within the 'Master Unit Rates Table' referred by each zone substation project customised estimate was benchmarked against industry peer which we generally consider to be reasonable. We also checked the unit cost information across each zone substation project customised estimates for consistency and against the pricebook. We did not identify any inconsistency within the zone substation building cost categories.

#### C.7.5.5 Contingency factors

No contingency factors have been included in the zone substation expenditure forecast.

#### C.7.5.6 Interaction with other forecast expenditures

**Zone substation projects:** The individual zone substation expenditure for buildings, power transformer, indoor and outdoor switchgear are embedded within the overall zone substation site project forecast and its capital cost estimates – which is driven by the scope of corresponding power transformer and

switchgear renewal works – is highly dependent on the forecast expenditure of other zone substation asset fleet.

**Buildings, grounds and ancillary equipment:** The zone substation building renewal expenditure should be informed by the result of maintenance and inspection regime, and will impact the future maintenance and inspection regime. However, the life cycle asset strategy for this civil fleet is not mature enough presently for Aurora Energy to quantitatively identify the future benefit/expense to the maintenance inspection regime.

### C.7.6 Deliverability

**Zone substation projects:** Aurora Energy used the separate coordination tool to:

1. review the entire portfolio of asset replacements
2. develop optimised bundling of work into site projects
3. ensure that both renewal and growth projects are programmed to occur in an orderly manner over the 10 years planning period so that the overall program of work is deliverable.

Our observations on capex deliverability, in general, have been provided in section 4.5. With regard to power transformer replacement work in the zone substation renewal work, establishing relationships with Electronet, Electrix and BroadSpectrum for open market tender participation – as Aurora Energy has done – should enable delivery of this capital work during the CPP and review periods. The recent formation of design service panel with engineering firms to deliver complex and overflow design work will also enable Aurora Energy to deliver the proposed workload.

Aurora Energy’s coordination model considers all discretely identified renewal and growth works in zone substations for timing, expenditure profile, bundling, resourcing and risk. We consider this to be a reasonable planning for this forecast expenditure from deliverability perspective.

**Buildings, grounds and ancillary equipment:** With regard to civil and building infrastructure work in the zone substation renewal work, the relationships with Electronet, Electrix and BroadSpectrum for open market tender participation should also enable delivery of this capital work during the CPP and review periods.

Aurora Energy’s coordination model considers all discretely identified renewal and growth works in zone substations for timing, expenditure profile, bundling, resourcing and risk – this is a reasonable planning for this forecast expenditure from deliverability perspective.

### C.7.7 Our finding

**Zone substation projects:** Our findings on Aurora Energy’s zone substation renewal program over the CPP and review periods are that:

- the coordination model is a good method to consider and challenge all potential works into separate zone substation ‘projects’ to enable efficiencies to be gained in bundling work into specific site projects over the 10-year planning horizon
- Aurora Energy has tested and considered options for each substation project leading to final concept designs and estimates
- the expenditure forecast for the identified projects over the CPP and review periods are not unreasonable.

We have also individually examined all the inputs that determines the cost components for building, grounds and ancillary equipment below, and power transformers, indoor and outdoor switchgear in the following sections.

**Buildings, grounds and ancillary equipment:** As Aurora Energy matures in its asset management journey, it is expected that it will build-up asset information of this civil fleet. This will allow Aurora Energy to conduct risk assessments of this civil infrastructure fleet in similar manner to its other asset fleet – which will enable identification and forecasting of renewal expenditure and support in justifying those forecasts.

Aurora Energy is also expected to implement a mature asset strategy for this civil infrastructure fleet that seamlessly considers all the life cycle activities and informs operational decisions.

Our review of the asset replacement modelling and our findings are presented in section D.7.10.

### C.7.8 Completeness and key issues for the Commission

**Zone substation projects:** Completeness and key issues related to power transformers, indoor and outdoor switchgear are addressed in the following sections C.8, C.9 and C.10.

**Buildings, grounds and ancillary equipment:** The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP and review periods.

## C.8 ZONE SUBSTATION RENEWAL – POWER TRANSFORMERS (C5.1)

Table C.12: Verification summary – Zone substation – power transformers (\$2020, \$millions)

<b>Expenditure category</b>	Zone substation power transformer renewals	
<b>Aurora Energy CPP forecast</b>	Power transformers cost component is embedded within the overall zone substation category, which is as follows: CPP period: \$26.5 million Review period: \$41.9 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$26.5 million Review period: \$41.9 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>We examined all the inputs that determine the power transformer cost component estimate embedded within the overall zone substation forecast expenditure. Given a relatively small population and good asset attribute, condition and performance information has allowed Aurora Energy to perform a robust risk assessment on this asset fleet. Unlike the unidimensional<sup>142</sup> risk assessment performed for its volumetric fleet, the risk assessment for power transformer fleet simultaneously considers both asset health and criticality. Various inputs to this risk assessment (i.e. age profile, inspection results, measurements, security, loads type, transfer capability etc.) are considered reasonable. This results in more precise and optimised expenditure forecast.</p> <p>We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the power transformer cost component</p>	<p>We examined all the inputs that determine the power transformer cost component estimate embedded within the overall zone substation forecast expenditure. We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the power transformer cost component.</p>

<sup>142</sup> I.e. only considering probability of failure (proxy by remaining age) assessment.

<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We considered WSP’s independent review of network risk and suggested recommendations</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy</p>
<b>What needs to be done</b>	<p>NA</p>
<b>Potential scope for improvement</b>	<ul style="list-style-type: none"> <li>• Enhance the present risk assessment methodology adopted for this asset fleet by monetising the criticality assessment. Doing so will allow objective articulation of risk in the business case enriching the argument for risk driven expenditure proposal. This will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).</li> <li>• Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a ‘line of sight’ and drive asset management improvements. Presently the various inputs to the AHI and Criticality models<sup>143</sup> can be treated as proxy performance metrics which determines the risk level, however, these inputs have not been called out in the asset management plan and asset strategy to provide the ‘line of sight.’</li> </ul>

### C.8.1 Project description

In last five years, Aurora Energy’s average power transformer capital expenditure (including both repex and augex) was approximately \$430,000 per annum.<sup>144</sup> Also, Aurora Energy has experienced above industry average power transformer failure rate in recent years.

For the review period, Aurora Energy has proposed to replace 11 power transformers based on its risk assessment and coordination planning of forecast zone substation together with other discretely identified renewal and growth works in the same site. The scope of each power transformer renewal project is site specific and closely related with the associated indoor switchgear and/or outdoor switchgear work in the same site.

### C.8.2 Cost estimate / expenditure forecast

The costs allocated to power transformer component within the zone substation expenditure forecast is based on customised estimate for each zone substation site renewal work using the building block from the pricebook. The power transformer cost component is a site-specific estimate build-up.

<sup>143</sup> Generally, the inputs to the AHI model can be treated as opex performance metrics and some of the inputs to the Criticality model can be treated as planning or design (i.e. capex) performance metrics.

<sup>144</sup> See spreadsheet embedded within: Aurora Energy, *RFI No D472 - Aurora Energy Information Request Response – ICT data*, 17 March 2020.

### C.8.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed several such operational standards and forms related to power transformer, tap changers and surge arrestor. Aurora Energy should maintain the currency and relevancy of these operational documents as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant policies.

The underlying analysis in POD09, prepared for the CPP proposal and which can be viewed as the latest version of the fleet specific asset plan, is more advanced and matured than the approach outlined in the AMP 2018-28. We believe this asset plan provides the most robust risk assessment out of all the asset portfolio and thereby supporting the identification of renewal project and forecast expenditure well. We are satisfied that this asset plan provides effective direction to manage this fleet of Aurora Energy's network assets.

### C.8.4 Information provided

Section D.8.1 presents the information that has been provided by Aurora Energy in relation to the zone substation power transformer program.

### C.8.5 Assessment of forecast method used

#### C.8.5.1 Expenditure trends

In recent past Aurora Energy has spent little capital on renewing its zone substation power transformer fleet. As mentioned earlier, the power transformer replacement costs constitute only a part of the overall zone substation expenditure forecast. In other words, the power transformer cost component is embedded within the forecast shown in the above figure. Also, the scopes of power transformer replacement are specific and vary in each zone substation that it is included, and in some sites the renewal scope does not include any power transformer replacement.

#### C.8.5.2 Expenditure justification

Apart from some issues noted in section D.8.7 (and not repeating here) pertaining to the use of the input data in conducting the asset health assessment and the mechanics of the coordination model, Aurora Energy has satisfactorily established the need for the power transformer replacement and for the inclusion of such replacement in the overall zone substation renewal program.

The underpinning drivers of the individually identified power transformer replacements are appropriately identified and explained. The need is aligned with its risk management framework and asset management principle. The timing of the need is consistent with prudent forecast work planning that considers bundling of discrete scope of works separately identified in the same site, resourcing and risk.

Given the relatively small size of power transformer population in its network and availability of good asset attribute, condition and performance data, Aurora Energy conducted a robust risk assessment on this asset fleet to individually identify replacement project and forecast renewal expenditure. It

simultaneously considered both asset health assessment and criticality assessment (i.e. AHI vs criticality risk matrix) to determine the risk level of each power transformer.

In assessing the asset health Aurora Energy considered the following index factor inputs:

- remaining asset life
- main tank visual inspection result
- cooler/radiator visual inspection result
- tap changer mechanism visual inspection result
- number of tap changer operations
- oil tests (DP/Furan and dissolved gas analysis) measurement.

These inputs are proportionally factored in to formulate a weighted AHI to proxy probability of asset failure.

Similarly, Aurora Energy considered the following inputs in determining criticality score factors:

- network security (N, N-1 switched, N-1)
- load type supplied (CBD, Urban, Rural)
- load magnitude (MVA)
- load transfer capability (% of load).

These inputs are proportionally factored in to formulate a weighted criticality score to proxy consequence of asset failure.

Power transformer within the intolerable region of the AHI vs. criticality risk matrix region are identified for risk treatment action. This approach is consistent with Aurora Energy's corporate risk management framework. This approach also results in precise and optimised project identification and forecast expenditure. We consider this approach to be reasonable.

For this renewal program we are satisfied that Aurora Energy has assessed various feasible options (consisting of various asset fleets including power transformer replacement work in the project scope) to address the need (including consideration of decommissioning of the site and non-network solutions). Each of the options were tested against the following criteria:

- meeting safety requirements
- meeting business need
- cost effective
- practicality of implementation
- alignment with good industry practice
- alignment with other planned works
- strategic fit.

Options were shortlisted and a preferred option was selected for each zone substation renewal work. The estimate of the preferred option was then further refined using the pricebook building block cost information and the scope of work included in the preferred option. Aurora Energy has assumed two years duration to undertake each proposed zone substation renewal project with 30% expended in the first year and the remaining 70% expended in the second year.

To further enhance Aurora Energy's risk assessment methodology and asset strategy related to zone substation power transformers, Aurora Energy should explore monetising the criticality assessment.

Doing so will allow objective articulation of risk in the business case for risk mitigation treatment plan (i.e. expenditure proposal). This will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).

Aurora Energy should also establish asset performance measurements (like the various inputs to AHI and Criticality assessments) that reflects safety outcome, supply reliability, asset failures, VoLL etc. and formally identify such metrics across its asset management plan and strategy for this fleet. Doing so will provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements.

### **C.8.5.3 Key assumptions used**

Given the critical nature of this asset fleet, the volume of work being proposed, and the approach adopted by Aurora Energy to identify power transformer replacement works and proposing them in the zone substation expenditure forecast (as explained earlier), no material assumptions underpinning the forecast have been used.

We have assessed the cost estimation in the following benchmarking section.

### **C.8.5.4 Benchmarking**

The unit costs for zone substation power transformer categories within the 'Master Unit Rates Table' referred by each zone substation project customised estimate was benchmarked against industry peer and were generally found reasonable. We also checked the unit cost information across each zone substation project customised estimates for consistency and against the pricebook. We did not identify any inconsistency within the zone substation power transformer cost categories.

We benchmarked Aurora Energy's zone substation power transformer per annum major failure rate against the available Australian and New Zealand CIGRE survey data and against the statistics available in the RIN data for Australian EDBs. In both comparisons the Aurora Energy's failure rate is more than the industry statistic. This is explained in detail in section D.8.4. This may be the result of either historical sub-optimal opex activities and/or appetite to operate zone substation power transformer even at intolerable risk level. We have used this above average failure rate reference to form a view that the proposed power transformer replacement is required to achieve the ALARP (i.e. cost vs risk reduction benefit) balance.

### **C.8.5.5 Contingency factors**

No contingency factors have been included in this expenditure forecast.

### **C.8.5.6 Interaction with other forecast expenditures**

The individual zone substation power transformer expenditure is embedded within the overall zone substation site project forecast and its timing is highly dependent on the forecast expenditure of other zone substation asset fleet.

The zone substation power transformer renewal expenditure should be informed by the result of maintenance and inspection regime, and will impact the future maintenance and inspection regime.

## **C.8.6 Deliverability**

We have addressed deliverability of the transformer renewal needs and expenditure in section C.8.

### **C.8.7 Our finding**

The expenditure forecast for this renewal program is based on individually identified power transformers across various zone substation sites by a robust risk assessment approach and its customised cost estimates.

We have reviewed all the inputs used to identify and estimate this expenditure forecast and consider them to be reasonable. Our review of the asset replacement modelling and our findings are presented in section D.8.8.

### **C.8.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP and review periods.

The Commission may also want to consider reviewing a few selected zone substation power transformer replacement projects for their scope, option analysis and risk assessment – and the underlying AHI and criticality modelling and the sources of inputs data – and coordination with other works to clarify the issues noted in section D.8.8.

## C.9 ZONE SUBSTATION RENEWAL – INDOOR SWITCHGEAR (C5.2)

Table C.13: Verification summary – Zone substation – indoor switchgear (\$2020, \$millions)

<b>Expenditure category</b>	Zone substation indoor switchgear renewal program	
<b>Aurora Energy CPP forecast</b>	Indoor switchgear cost component is embedded within the overall zone substation category, which is as follows: CPP period: \$26.5 million Review period: \$41.9 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$26.5 million Review period: \$41.9 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>We examined all the inputs that determines the indoor switchgear cost component estimate embedded within the overall zone substation forecast expenditure.</p> <p>Given a relatively small population and good asset attribute and performance information has allowed Aurora Energy to perform a reasonable risk assessment on this asset fleet. Unlike the unidimensional<sup>145</sup> risk assessment performed for its volumetric fleet, the risk assessment for indoor switchgear fleet simultaneously considers both asset health and criticality. Various inputs to this risk assessment (i.e. remaining age, protection clearing time, fault rating, spare part availability, load at risk etc.) are considered reasonable. This results in more precise and optimised expenditure forecast.</p> <p>We questioned the initial inclusion of the City South 11 kV indoor switchboard in the replacement program. Aurora Energy subsequently reviewed the zone substation program and deferred the replacement of the City South switchboard beyond RY26 and brought forward replacement of Smith Street switchboard into the review period. The Smith Street</p>	<p>We examined all the inputs that determines the indoor switchgear cost component estimate embedded within the overall zone substation forecast expenditure.</p> <p>We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the indoor switchgear cost component.</p>

<sup>145</sup> That is, only considering probability of failure assessment, which was approximated by remaining age.

	<p>switchboard was identified with higher priority in the renewal model.</p> <p>We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the indoor switchgear cost component</p>	
<p><b>Other relevant criteria from ToR</b></p>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies have cascaded down to developing the indoor switchgear strategy and plans. We considered WSP’s independent review of network risk and suggested recommendations.</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up asset attribute, condition, and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.</p>	
<p><b>What needs to be done</b></p>	<p>NA</p>	
<p><b>Potential scope for improvement</b></p>	<ul style="list-style-type: none"> <li>• Incorporate the inspection result and measurements from maintenance activities conducted on this fleet to build-up the asset condition data and use them to assess asset health in conjunction with the remaining age data.</li> <li>• Enhance the present risk assessment methodology adopted for this asset fleet by monetising the criticality assessment. Doing so will allow objective articulation of risk in the business case enriching the argument for risk driven expenditure proposal. This will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).</li> <li>• Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a ‘line of sight’ and drive asset management improvements. Presently the inputs to the criticality models is the asset specification or the network configuration attribute, and not strictly the performance of the asset themselves.</li> </ul>	

### C.9.1 Project description

In last five years, Aurora Energy’s average indoor switchgear capital expenditure (including both repex and augex) was approximately \$1.35 million per annum. For the review period, Aurora Energy has proposed to replace six indoor switchboards based on its risk assessment and coordination of forecast zone substation projects with other discretely identified renewal and growth works at each site. The scope of each indoor switchgear renewal project is site-specific and closely related with the associated power transformer work at each site.

### C.9.2 Cost estimate / expenditure forecast

The costs allocated to indoor switchgear component within the zone substation expenditure forecast is based on customised estimate for each zone substation site renewal work using the building block from the pricebook. The indoor switchgear cost component is a site-specific estimate build-up.

### C.9.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of such operational standards and forms related to indoor switchgear asset fleet (Vacuum CB, SF6 CB, Oil CB and LV busbar). Aurora Energy should maintain the currency and relevancy of these operational documents as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant policies.

The underlying analysis in POD09, prepared for the CPP proposal and which can be viewed as the latest version of the fleet specific asset plan, is more advanced and matured than the approach outlined in the AMP 2018-28. We believe this asset plan provides a reasonable risk assessment and thereby supports the identification of renewal project and forecast expenditure well. We are satisfied that this asset plan provides effective direction to manage this fleet of Aurora Energy's network assets.

### C.9.4 Information provided

Section D.9.1 presents the information that has been provided by Aurora Energy in relation to the zone substation indoor switchgear renewal program.

### C.9.5 Assessment of forecast method used

#### C.9.5.1 Expenditure trends

In recent past Aurora Energy has spent little capital on renewing its zone substation indoor switchgear fleet. As mentioned earlier, the indoor switchgear replacement costs constitute only a part of the overall zone substation expenditure forecast. In other words, the indoor switchgear cost component is embedded within the zone substation renewal forecast throughout the forecast period. Also, the scopes of indoor switchgear replacement are specific and vary in each zone substation that it is included, and in some sites the renewal scope does not include any indoor switchgear replacement.

#### C.9.5.2 Expenditure justification

Aurora Energy had initially included City South 11 kV indoor switchboard for replacement in the review period. However, it was not one of the six highest priority switchboard requiring replacement. Smith Street 11 kV switchboard – which *was* – was instead deferred beyond the review period despite being listed in the six switchboards with the highest risk.

Following discussions with Aurora Energy, the zone substation program was reviewed by Aurora Energy and the Smith Street switchboard was brought forward to be included in the review period for replacement the City South switchboard deferred beyond RY26.

We consider that Aurora Energy has satisfactorily established the need for the six indoor switchgear replacement projects over the review period. The underpinning drivers of the specific indoor switchboard replacements are appropriately identified and explained. The need is aligned with its risk management framework and asset management principle. The timing of the need is consistent with prudent forecast work planning that considers bundling of discrete scope of works separately identified in the same site, resourcing and risk.

Given the relatively small size of indoor switchboard population in its network and availability of good asset attribute and performance data, Aurora Energy conducted a reasonable risk assessment on this asset fleet to individually identify replacement project and forecast renewal expenditure. It simultaneously considered both asset health assessment and criticality assessment (i.e. AHI vs criticality risk matrix) to determine the risk level of each indoor switchboard.

While the asset health index is based only on the remaining asset life to proxy the probability of asset failure, the criticality score is based on the following factors:

- protection clearing time (none, frame leakage, arc flash, bus differential)
- fault rating capability vs actual network fault level (% headroom)
- spare part availability (yes, no)
- consumer load at risk (MVA)
- load transfer capability (% of load).

These inputs formulate a weighted criticality score to proxy consequence of asset failure.

Indoor switchgear within the intolerable region of the AHI vs. criticality risk matrix region are identified for risk treatment action. This approach is consistent with Aurora Energy's corporate risk management framework and results in precise and optimised project identification and forecast expenditure. We consider this approach to be reasonable.

For this renewal program we are satisfied that Aurora Energy has assessed various feasible options (consisting of various asset fleets including indoor switchgear replacement work in the project scope) to address the need (including consideration of decommissioning of the site and non-network solutions). Each of the option were tested against the following criteria:

- meeting safety requirements
- meeting business need
- cost effective
- practicality of implementation
- alignment with good industry practice
- alignment with other planned works
- strategic fit.

Options were shortlisted and a preferred option selected for each zone substation renewal project. The estimate of the preferred option was then further refined using the pricebook building block cost information and the scope of work included in the preferred option. Aurora Energy has assumed two years duration to undertake each proposed zone substation renewal project with 30% expended in the first year and the remaining 70% expended in the second year.

To further enhance Aurora Energy's risk assessment methodology and asset strategy related to indoor switchgear, Aurora Energy should:

- incorporate the inspection result and measurements from the asset maintenance activities to build-up the asset condition data and use them to assess asset health in conjunction with remaining asset age data
- explore monetising the criticality assessment – doing so will allow objective articulation of risk in the business case for risk mitigation treatment plan (i.e. expenditure proposal); this will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).

Aurora Energy should also establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. and formally identify such metrics across its asset management plan and strategy for this fleet. Doing so will provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements. Presently the inputs to the criticality models is the asset specification or the network configuration attribute, and not strictly the performance of the asset themselves.

### C.9.5.3 Key assumptions used

Given the critical nature of this asset fleet, the volume of work being proposed, and the approach adopted by Aurora Energy to identify indoor switchgear replacement works and proposing them in the zone substation expenditure forecast (as explained earlier), each proposed indoor switchgear replacement has assumptions underpinning the customised cost estimates. We have assessed the cost estimation in the following benchmarking section.

### C.9.5.4 Benchmarking

The unit costs for zone substation indoor switchgear categories within the 'Master Unit Rates Table' referred by each zone substation project customised estimate was benchmarked against industry peers which we generally consider to be reasonable. We also checked the unit cost information across each zone substation project customised estimates for consistency and also against the pricebook. We did not identify any inconsistency within the zone substation indoor switchgear cost categories.

We benchmarked Aurora Energy's zone substation indoor switchgear planned replacement rate against Powerco and two other Australian EDB proposals.<sup>146</sup> In comparison, Aurora Energy's planned replacement rate is higher than the industry peers' recent proposals. However, considering Aurora Energy's historical expenditure in zone substation renewal works the proposed replacement level is reasonable.

### C.9.5.5 Contingency factors

No contingency factors have been included in this expenditure forecast.

### C.9.5.6 Interaction with other forecast expenditures

The individual zone substation indoor switchgear expenditure is embedded within the overall zone substation site project forecast and its timing is highly dependent on the forecast expenditure of other zone substation asset fleet.

The zone substation indoor switchgear renewal expenditure should be informed by the result of maintenance and inspection regime, and will impact the future maintenance and inspection regime.

## C.9.6 Deliverability

We have addressed deliverability of the transformer renewal needs and expenditure in section C.8.

## C.9.7 Our finding

The expenditure forecast for this renewal program based on the review of the asset replacement modelling and our findings are presented in section D.9.8.

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<sup>146</sup> SA Power Networks and Western Power.

### **C.9.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP and review periods.

## C.10 ZONE SUBSTATION RENEWAL – OUTDOOR SWITCHGEAR (C5.3)

Table C.14: Verification summary – Zone substation – outdoor switchgear (\$2020, \$millions)

<b>Expenditure category</b>	Zone substation outdoor switchgear renewal	
<b>Aurora Energy CPP forecast</b>	Outdoor switchgear cost component is embedded within the overall zone substation category, which is as follows: CPP period: \$26.5 million Review period: \$41.9 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$26.5 million Review period: \$41.9 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>We examined all the inputs that determines the outdoor switchgear cost component estimate embedded within the overall zone substation forecast expenditure</p> <p>We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the outdoor switchgear cost component.</p> <p>We accept the proposed forecast volume based on our assessment of the following factors:</p> <ul style="list-style-type: none"> <li>• asset age information and its translation to asset health score</li> <li>• coordination logic to bundle together renewal and growth projects with the objective of managing resourcing levels and aligning timing of works at the same site.</li> </ul>	<p>We examined all the inputs that determines the outdoor switchgear cost component estimate embedded within the overall zone substation forecast expenditure.</p> <p>We accept the proposed unit cost estimate of the underlying building blocks from the pricebook that was used to build-up the outdoor switchgear cost component.</p>
<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing the outdoor switchgear strategy and plans. We considered WSP’s independent review of network risk and suggested recommendations.</p> <p>We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up asset condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.</p>	
<b>What needs to be done</b>	NA	

#### Potential scope for improvement

- Incorporate the inspection result and measurements from maintenance activities conducted on this fleet to build-up the asset condition data and use them to assess asset health in conjunction with the remaining age data.
- Similar to the indoor switchgear fleet, develop criticality assessment for this fleet by considering asset attributes, substation design, network configuration, load characteristics etc.
- Conduct robust risk assessment by simultaneously considering both asset health and criticality scores. This will refine the expenditure forecast precision and the asset strategy for targeted risk mitigation.
- After developing the criticality model for this asset fleet enhance it further by monetising the criticality assessment. Doing so will allow objective articulation of risk in the business case enriching the argument for risk driven expenditure proposal. This will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).
- Establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. Such measurement will help in determining the residual risk and provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements.

### C.10.1 Project description

In last five years, Aurora Energy has had almost negligible capital expenditure in this asset fleet including both repex and augex. For the review period, Aurora Energy has proposed to replace 35 switches and 26 circuit breakers and reclosers based on its risk assessment and coordination planning of forecast zone substation together with other discretely identified renewal and growth works in the same site. The scopes of each outdoor switchgear renewal project are site specific and closely related with the associated power transformer work in the same site.

### C.10.2 Cost estimate / expenditure forecast

The costs allocated to outdoor switchgear component within the zone substation expenditure forecast is based on customised estimate for each zone substation site renewal work using the building block from the pricebook. The outdoor switchgear cost component is a site-specific estimate build-up.

### C.10.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. It translates the intention of its policies to management plans that guides operational asset management activities. It refers to collection of standards throughout the asset life cycle management steps. We reviewed a number of such operational standards and forms related to outdoor switchgear asset fleet (Vacuum CB, SF6 CB, Oil CB, CT, VT and Recloser). Aurora Energy should maintain the currency and relevancy of these operational document as it progresses through its asset management maturity journey. The AMP also describes the enablers for successful implementation of the relevant polices.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy's network assets. Aurora Energy is however presently limited by its asset condition and performance data availability and quality that would otherwise enable it to target investment and risk mitigation measures with much greater precision, and in the process further optimise asset strategies and expenditure forecasts.

We expect to see an improvement to this situation given the outlined asset strategy (maintenance and inspection regime that will provide quality asset data recording opportunity), investment in IT and project management systems, capacity and staff capability building, and harvesting of better quality life cycle asset management information.

#### **C.10.4 Information provided**

Section D.10.1 presents the information that has been provided by Aurora Energy in relation to the zone substation outdoor switchgear renewal program.

#### **C.10.5 Assessment of forecast method used**

##### **C.10.5.1 Expenditure trends**

In recent past Aurora Energy has spent negligible capital on renewing its zone substation outdoor switchgear fleet. As mentioned earlier, the outdoor switchgear replacement costs constitute only a part of the overall zone substation expenditure forecast. In other words, the outdoor switchgear cost component is embedded within the zone substation renewal forecast throughout the forecast period. Also, the scopes of outdoor switchgear replacement are specific and varies in each zone substation that it is included, and in some sites the renewal scope does not include any outdoor switchgear replacement.

##### **C.10.5.2 Expenditure justification**

We consider that Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning drivers are appropriately identified, the asset data limitation described, and the assumption used to support the case has been explained. The need is generally aligned with its risk management framework and asset management principle. The timing of the need is also generally consistent with the asset fleet age profile, interlinked with the timing of associated power transformer replacement or upgrade or addition, and considers bundling of discrete scope of works separately identified in the same site, resourcing and risk.

For this renewal program we are satisfied that Aurora Energy has treated the different type of outdoor switchgear accordingly.

However, the risk assessment for this asset fleet consist of only considering the asset health score which is a simple asset remaining life measure. No other asset condition data is utilised for asset health assessment due to the unavailability or quality issue of such information. Similarly, the criticality assessment is not performed for this asset fleet. Instead the criticality assessment of the associated power transformer is considered as a proxy score. Therefore, the risk assessment methodology for this zone substation asset fleet is underdeveloped in comparison to other zone substation asset fleets.

We are aware of the risk assessment documented in the WSP report (Section 16.6, Page 162) where the criticality has been simultaneously considered along with asset health which has informed in the identification and forecasting of outdoor switchgear preplacement projects.

We believe that without the simultaneous consideration of both asset health and criticality, the risk assessment tends to forecast a risk averse expenditure. Nevertheless, we are satisfied that the identification of the outdoor switchgear replacement project is closely interlinked with zone substation criticality profile and then coordinated with other discrete zone substation works to bundle them by considering the risk, resourcing and synergies. These steps have provided prudence checks. Also, given this risk assessment context for this zone substation asset fleet, and to further form a view on the reasonableness of the forecast expenditure, we benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is explained in Section C.10.5.4.

For this renewal program we are satisfied that Aurora Energy has assessed various feasible options (consisting of various asset fleets including outdoor switchgear replacement work in the project scope) to address the need (including consideration of decommissioning of the site and non-network solutions). Each of the option were tested against the following criteria:

- meeting safety requirements
- meeting business need
- cost effective
- practicality of implementation
- alignment with good industry practice
- alignment with other planned works
- strategic fit.

Options were shortlisted and a preferred one selected for each zone substation renewal work. The estimate of the preferred option was then further refined using the pricebook building block cost information and the scope of work included in the preferred option. Aurora Energy has assumed two years duration to undertake each proposed zone substation renewal project with 30% expended in the first year and the remaining 70% expended in the second year.

To develop Aurora Energy's risk assessment methodology and asset strategy related to outdoor switchgear and bring it up to the similar standard as power transformer fleet, Aurora Energy should:

- incorporate the inspection result and measurements from the asset maintenance activities to build-up the asset condition data and use them to assess asset health in conjunction with remaining asset age data
- similar to the indoor switchgear fleet, develop criticality assessment for this fleet by considering asset attributes, substation design, network configuration, load characteristics etc
- explore monetising the criticality assessment – doing so will allow objective articulation of risk in the business case for risk mitigation treatment plan (i.e. expenditure proposal); this will also enable objective assessment of ALARP position (i.e. cost vs risk reduction benefit balance).

Aurora Energy should also establish asset performance measurements that reflects safety outcome, supply reliability, asset failures, VoLL etc. and formally identify such metrics across its asset management plan and strategy for this fleet. Doing so will provide accountability for expenditure outcome by offering a 'line of sight' and drive asset management improvements.

### C.10.5.3 Key assumptions used

The asset health assessment assumes expected asset lives for various types of outdoor switchgear which we consider are reasonable assumptions. This is the only factor, along with the asset age profile, that forms the input to the risk assessment methodology for this asset fleet.

The only other set of assumptions used is the underlying information utilised to build-up the customised cost estimates in the portfolio of proposed zone substation renewal works. We have assessed the cost estimation in the following benchmarking section.

#### **C.10.5.4 Benchmarking**

The unit costs for zone substation outdoor switchgear categories within the ‘Master Unit Rates Table’ referred by each zone substation project customised estimate was benchmarked against industry peer which we generally found were reasonable. We also checked the unit cost information across each zone substation project customised estimates for consistency and against the pricebook. We did not identify any inconsistency within the zone substation outdoor switchgear cost categories.

We benchmarked Aurora Energy’s zone substation outdoor switchgear planned replacement rate against Powerco and two other Australian EDBs proposals.<sup>147</sup> In comparison Aurora Energy’s planned replacement rate is higher than the industry peers’ recent proposals. However, considering Aurora Energy’s historical expenditure for zone substation outdoor switchgear renewal works in comparison of sustained historical renewal works for the other businesses, we consider that the proposed replacement level is reasonable. We have also used this replacement rate benchmark reference to form a view that the proposed outdoor switchgear replacement expenditure is required to achieve the ALARP (i.e. cost vs risk reduction benefit) balance.

#### **C.10.5.5 Contingency factors**

No contingency factors have been included in this expenditure forecast.

#### **C.10.5.6 Interaction with other forecast expenditures**

The individual zone substation outdoor switchgear expenditure is embedded within the overall zone substation site project forecast and its timing is highly dependent on the forecast expenditure of other zone substation asset fleet.

The zone substation outdoor switchgear renewal expenditure should be informed by the result of maintenance and inspection regime, and will impact the future maintenance and inspection regime.

#### **C.10.6 Deliverability**

We have addressed deliverability of the transformer renewal needs and expenditure in section C.8.

#### **C.10.7 Our finding**

The expenditure forecast for this renewal program based on the review of the asset replacement modelling and our findings are presented in section D.10.7.

#### **C.10.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

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<sup>147</sup> SA Power Networks and Western Power.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements for its renewal programs over the CPP and review periods.

We suggest that Commission also consider the potential scope for improvement for assessing the risk profile of this asset fleet and using it to identify and propose the forecast expenditure. This forms an integral part of Aurora Energy's asset management journey.

## C.11 LV ENCLOSURES RENEWALS (C6)

Table C.15: Verification summary – LV enclosures renewal (\$2020, \$millions)

<b>Expenditure category</b>	LV enclosures renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$5.8 million Review period: \$9.0 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$5.8 million Review period: \$9.0 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>This is a volumetric forecast. We examined all the inputs that can inform a justified forecast expenditure.</p> <p>We accept the proposed forecast replacement of LV enclosures after adjustments were made to the volume forecasts for above ground LV enclosures. The adjustments reflected:</p> <ul style="list-style-type: none"> <li>• recent Inspection data for 49% of the fleet</li> <li>• safety risks with known enclosure types</li> <li>• percentage of enclosures found to be hazardous</li> <li>• benchmarking with industry peers.</li> </ul>	<p>We were initially not satisfied with the proposed unit cost estimate for ‘other enclosures’ types based on our assessment of cost data benchmarking. Aurora Energy provided additional benchmarks from other EDBs and costs data on recent projects Aurora Energy has completed.</p> <p>We are now satisfied that the unit rates are consistent with the expenditure objective.</p> <p>We were initially also not satisfied with the proposed forecast volumes which have since been reviewed and adjusted by Aurora Energy. We are now comfortable with the forecasts.</p>
<b>Other relevant criteria from ToR</b>	<p>We considered the maturity of Aurora Energy’s asset management system together with its corporate risk management framework and how these philosophies, aspiration and current limitations have cascaded down to developing individual asset fleet plans. We consider the intent of addressing safety risks associated with LV enclosures is in line with these policies.</p> <p>We also considered the data that was available to Aurora Energy to reasonably assess the risks with these assets. Our opinion is that the unavailability of condition data and particular incidents led to a high volume of replacements in initial forecasts. With the hindsight of recent inspection data, Aurora Energy has adjusted the forecast to reflect the current identified hazard rates.</p>	
<b>What needs to be done</b>	NA	

### Potential scope for improvement

Aurora Energy should accurately capture and build-up the asset attribute, condition and performance information to enable a risk assessment to be conducted. Aurora Energy should develop asset strategies to efficiently manage the risks including a stratified inspection regime and appropriate mitigation strategies. This will also enable objective assessment of ALARP position (i.e. cost vs safety benefit balance) to inform the LV enclosure asset strategy in the future.

Aurora Energy should establish performance measures that reflect residual safety risk to the public such as number of assisted and unassisted failures per annum.

Aurora Energy should also actively and regularly benchmark its asset management practices and unit costs where available with peer businesses in the industry with an aim to improve efficiency.

### C.11.1 Project description

Aurora Energy aims to initiate this renewal program in RY20. There was no dedicated renewal program for this asset fleet prior to that.

Aurora Energy owns approximately 21,000 LV enclosures that are used in the low voltage supply network. The makes and types of enclosures vary widely. Underground link boxes (265) are in poor condition and most are more than 45 years of age. They are no longer operated live due to safety risks and they have a high replacement cost.

The highest risk related to above ground LV enclosures are vehicle collisions and vandalism, which cannot be predicted. EDBs typically have public awareness campaigns in place with high priority emergency response for these incidents. Otherwise failures of pillars typically relate to supply interruption to one or two customers. There are types issues with P160/P260 metal enclosures pillars which can become live if uninsulated components could potentially come in contact with the metal outside cover posing a risk to the public.

Aurora Energy cited one worker safety incident with above ground LV enclosures after which a change of work practice has been put in place, and a public related shock incident occurring in the recent past.

Aurora Energy initially forecasted a higher volume for replacements for the above ground enclosures. After considering recent inspection data and our analysis in the draft report, Aurora Energy has reduced replacement volumes from an average of 401 LV enclosures per annum over the CPP period to 242.

### C.11.2 Cost estimate / expenditure forecast

Table C.16 shows the forecast expenditure during the CPP and review periods.

Table C.16: Forecast expenditure – LV enclosures renewal (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	1,896	1,965	1,954	1,753	1,463	5,814	9,030

### C.11.3 Relevant policies and planning standards

Aurora Energy is at an early stage of its asset management maturity journey. It has sound policies on asset management, risk framework and safety at a corporate level that aspires for industry best practice with respect to asset renewals. The AMP 2018-28 provides a good outline of Aurora Energy's approach to managing its network assets and mitigate its risk profile. LV enclosures are included in the most recent AMP covering this program.

We are satisfied that this asset management plan provides effective direction to manage this fleet of Aurora Energy's network assets. Aurora Energy is however presently limited by its asset data availability and quality that would otherwise enable it to target investment on the basis of informed risk mitigation measures. We reviewed the Mains Pillar Installation Form related to addressing this need to ensure asset data is collected and entered in the GIS database.

There is currently no criticality or asset risk management framework that provides guidance for the development of all asset classes. However, we note that it is not reasonable to expect that these frameworks are in place at this stage of the development of Aurora Energy's asset management system. Aurora Energy has advised that the intent is to develop these over the next two years. These frameworks would provide the direction and methodologies to conduct risk assessments for all types of asset classes. It is our view that asset strategies for LV enclosures would have benefit from having these frameworks in place.

### C.11.4 Information Provided

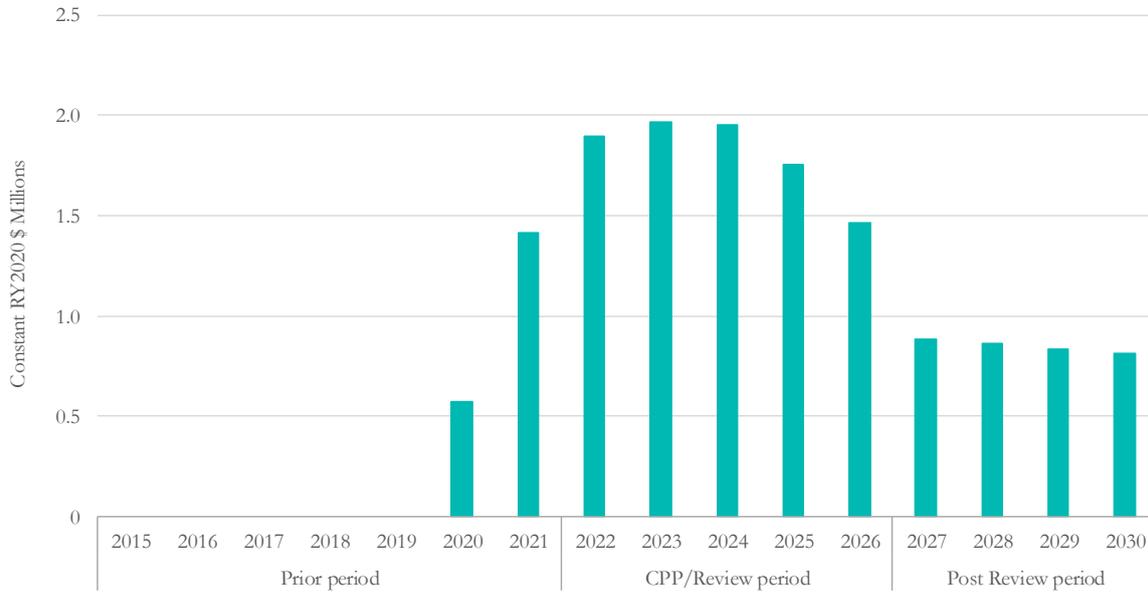
Section D.11.1 presents the information that has been provided by Aurora Energy in relation to the LV enclosures replacement program and D11.2 presents the other information that we have relied on.

### C.11.5 Assessment of forecast method used

#### C.11.5.1 Expenditure trends

Figure C.6 shows the historical and forecast expenditure for the LV enclosures replacement program.

Figure C.6: LV enclosures – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

The proposed expenditure is forecast to increase to an average of \$1.8 million per annum during the CPP and review periods and reducing to around \$0.8 million per annum over the RY27 to RY30 period.

### C.11.5.2 Expenditure justification

We consider that Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning driver to mitigate the safety risks are appropriately identified; however, the past unknown state of condition had limited Aurora Energy’s ability to adequately support the proposed replacements in total.

For this renewal program, Aurora Energy has a sufficient case for the replacement of all underground LV enclosures. Aurora Energy has planned to progressively replace most of these units by RY26.

The above ground enclosures with metal covers increases the risks of electric shocks to the public and workers. The renewal model used to forecast required replacements is essentially age based with an assumed normal distribution around the mean life expectancy (refer to Appendix D.11). The inspection program appears to now have coverage of 49% of the 21,000 enclosures that can inform a risk assessment.

Using this data, our assessment of risks in section D.11 and comparisons with other EDBs, suggests that the volumes forecast for the above ground LV enclosures should be reduced from that previously forecasted. Aurora Energy acknowledged the findings and adjusted the expected life input parameter in MOD: 18 (23 April 2020) to 47.5 years which produces a revised replacement volume aligned to our proposed reduction.

The adjusted replacement forecast is \$9.5 million in total and \$5.4 million for the above ground and underground enclosures. This contrasts with the expenditure forecasts of between \$1.1 million to \$2.3 million of the other New Zealand EDBs that we considered, some notably having had programs in place previously.

We accept the unit rate for underground enclosures and link boxes at \$30,000. With respect to unit rates in the forecast model, we compared the rates with several comparable unit prices for LV enclosure replacements – based on our commercial and industrial experience in the Australian electricity market.

We were initially unsure whether Aurora Energy's replacement rate for above ground enclosures (at \$5,000 per unit) was too high or not. Aurora Energy provided additional benchmarks from other EDBs and costs data from 25 of its own recent completed LV enclosure renewal projects. We are now satisfied that the unit rate of \$5000 is not unreasonable.

We benchmarked Aurora Energy's volume forecast with industry peer businesses with similar risk profiles. This is explained in section D.4.4. The unit cost benchmarking is detailed in section C.11.5.4 below.

### C.11.5.3 Key assumptions used

The key assumption used by Aurora Energy in forecasting this expenditure in the model is the expected life for the enclosure types – and to a lesser extent, the statistical distribution of expected failures around the expected life. These assumptions were identified in POD18 and Aurora Energy acknowledges that this was only an estimate. Aurora Energy has updated the initial assumptions by considering condition data from recent inspections and comparison with other EDBs to gain their experience from past replacement programs.

### C.11.5.4 Benchmarking

The main inputs such as unit cost and expected asset life used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers.

We initially considered the unit cost input for above ground LV enclosures was above comparable rates available to us. Aurora Energy subsequently compare the LV enclosure unit rates with other EDBs with the following findings:

- many EDBs indicate that civil works, brownfield factors (i.e. not new builds and consideration of things like 'link pillar has fence built over it' (so must be relocated)) and the size of link / service pillars have a significant influence on cost – the cost range for these are in the region of \$1,000 to \$10,000
- some EDBs have excluded cable costs where relocation of the pillar is required, which Aurora Energy has observed to have a large influence on costs, and they are not covered in its LV cable renewals forecast, however, we also had not included these costs in our initial review of the rates
- a comparable EDB with a similar mix of service and link pillars and similar geography the average link and service pillar replacement rate is \$5,000.

An average of Aurora Energy's own past projects was \$5,003 which aligns with its forecast unit rate of \$5,000 per unit. Of the 25 past replacement projects, the range was between \$1,712 to \$19,239, with 76% between \$3,700 and \$5,695 – approximately -25% to +15% around the \$5,000 average. This wide range of past replacement costs illustrates the impact of projects with varying nature of scope such as the inclusion of LV cabling work, access issues and other costly site works.

### C.11.5.5 Contingency factors

No contingency factors have been included in this expenditure forecast.

#### **C.11.5.6 Interaction with other forecast expenditures**

The LV enclosure renewal program is planned to begin in RY20. There is no interaction with other capex programs.

There is a relationship between this program and the opex maintenance program; Preventive (O1), Corrective (O2) and Reactive (O3). The introduction cycle of LV enclosure inspections will have a small continuous uplift in maintenance expenditure since the base year RY19.

#### **C.11.6 Deliverability**

Our observations on capex deliverability, in general, have been provided section 4.5. With regard to LV enclosures, the skills required are readily available from Aurora Energy's contracted service providers.

#### **C.11.7 Our finding**

We have reviewed all the inputs used to identify and estimate this expenditure forecast and we consider that they are reasonable. Our review of the asset replacement modelling and our findings are presented in section D.11.9.

#### **C.11.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements and risk-based models for its renewal programs over the CPP and review periods.

## C.12 PROTECTION RENEWALS (C7)

Table C.17: Verification summary – Protection renewal program (\$2020, \$millions)

<b>Expenditure category</b>	Protection renewal program	
<b>Aurora Energy CPP forecast</b>	CPP period: \$6.7 million Review period: \$9.3 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$6.7 million Review period: \$9.3 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	This is a volumetric forecast. We examined all the inputs that determines the forecast expenditure. We accept the proposed forecast volume based on our assessment of the following factors: <ul style="list-style-type: none"> <li>• asset age information and assumptions</li> <li>• modelling logic and age-based replacement profile</li> <li>• asset life assumptions</li> <li>• scheduling priority over the period.</li> </ul>	We examined all the inputs that determines the forecast expenditure. We are satisfied with the proposed unit cost estimate based on our assessment of cost data benchmarking and asset scope review.
<b>Other relevant criteria from ToR</b>	We considered the maturity of Aurora Energy’s asset management system together with the corporate risk management framework and how these philosophies, aspirations and current limitations have cascaded down to this individual asset fleet plan. We considered WSP’s independent review of network risk and suggested recommendations.  We also considered the elements of asset strategy of this fleet that enables Aurora Energy to build-up and improve asset attribute, condition and performance data in the near future. We are satisfied with the capex and opex related activities included in the asset strategy.	
<b>What needs to be done</b>	NA	NA

### Potential scope for improvement

- Aurora Energy should diligently and accurately capture and build-up asset attribute, condition and performance information to enable accurate health and criticality assessment. Aurora Energy should simultaneously consider both failure probability (proxy by asset health) and failure consequence (proxy by criticality) for robust risk assessment thereby refining the expenditure forecast precision and the asset strategy for targeted risk management. This will result in refinement and optimisation of the protection systems asset strategy in the future.
- Extending the life of modern relays will have a significant impact on future expenditure and should form part of current asset strategies options to work with OEMs (and at an industry level) and develop a risk assessment methodology for these relays.
- Establish asset performance measurements that reflects safety outcomes and supply reliability (asset failures, VoLL and human error incidents etc). Such measurement will help in determining the residual risk and provide accountability for expenditure outcomes by offering a 'line of sight' and drive asset management improvements.
- Aurora Energy should actively and regularly benchmark its asset management practices and unit costs where available with peer businesses in the industry with an aim to improve its efficiency.

### C.12.1 Project description

Aurora Energy initiated this renewal program only from 2019. There was no dedicated renewal program for this asset fleet prior to that.

Protection relays operate to protect primary equipment and ensure the safety of employees, service providers and the public in the event of electrical faults. Reliable performance of protection relays is critical to the operation of our network and failure of protection to clear a fault poses a significant safety risk.

Aurora Energy is facing particular issues with relays end of life which generally relates to obsolescence, including lack of spares and higher cost to maintain. Approximately 60% of the relays are electromechanical and nearly all of these relays have exceeded their life expectancy. Many of Aurora Energy's static relays have also exceeded their expected life.

Aurora Energy has committed to remove all electromechanical relays from service by RY24 and all static relay types in RY25.

### C.12.2 Cost estimate / expenditure forecast

Table C.18 shows the forecast expenditure during the CPP and review periods.

**Table C.18: Forecast expenditure – protection renewals (\$2020, \$thousands)**

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
Expenditure	2,360	2,360	1,930	1,320	1,320	6,650	9,290

### C.12.3 Relevant policies and planning standards

The AMP 2018-28 provides a good outline of Aurora Energy’s approach to managing its network assets and to manage risks related to the protection fleet. It translates the intention of its policies to management plans that guides operational asset management activities.

We reviewed AE-NP01 - Sub-Transmission and Zone Substation Protection Standard in relation to design standards for new and replaced protection systems.

We are satisfied that this asset management plan (POD: 24) provides effective direction to manage this fleet of Aurora Energy’s network assets.

### C.12.4 Information provided

Section D.12.1 presents the information that has been provided by Aurora Energy in relation to the protection systems replacement program and D.12.2 presents the other information that we have relied on.

### C.12.5 Assessment of forecast method used

#### C.12.5.1 Expenditure trends

Figure C.7 shows the historical and forecast expenditure for the protection systems replacement program.

Figure C.7: Protection renewals – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

The proposed expenditure over the CPP period is forecast to continue at a rate of \$2.4 million per annum and begin to reduce down to \$1.3 million per annum by the end of the review period, and then a long run replacement expenditure of \$1.2 million per annum from RY27. There is potential in the long run to reduce annual expenditure through extended life of microprocessor relays.

### C.12.5.2 Expenditure justification

We consider that Aurora Energy has satisfactorily established the need for these renewals and to have a dedicated renewal program for this fleet. The underpinning drivers are appropriately identified based on obsolescence and the increasingly difficulty to ensure operation integrity of electromagnetic protection relays.

A specific risk model has not been developed for this asset fleet due to the inherent difficulty to translate protection relay condition and performance into a probability of failure or asset health model beyond simply replacement on age. This replacement strategy is consistent with industry practice.

For this renewal program we are satisfied that Aurora Energy has treated the different types of protection relay technologies and systems accordingly. Given the safety consequences of failure associated with protection system assets we are satisfied that there was no obvious omission.

The expenditure over the CPP and review periods has been determined by Aurora Energy based on considering the need to level the demand for the specialised technical workforce require, the need to prioritise based on failure consequence and the need to coordinate with zone substation projects.

We are aware of the risk assessment documented in WSP report (Section 17.6, Pages 178) where the criticality has been simultaneously considered along with failure probability indicating the need to urgently replace a large volume of protection relays. Aurora Energy intends to use criticality to refine the priority of protection schemes replacements not directly associated with zone substation projects.

Our assessment of the renewal model and asset strategy has been provided in section D.12. Our findings are that:

- The inputs used in the renewal model are appropriate including the key assumptions related to this asset class which includes a sound underpinning asset strategy.
- Aurora Energy has applied an appropriate method within the renewal model, appropriate for the asset type, which is also consistent with industry practice and hence likely to promote the expenditure objective.
- A benchmark with two other Australian industry distributors supports the reasonableness of the forecast replacement volumes.

While we are satisfied with the expenditure forecast based on the above needs, we have benchmarked Aurora Energy's forecast with industry peer businesses with similar risk profile. This is discussed in D.12.4.

### C.12.5.3 Key assumptions used

The key assumptions used in forecasting this expenditure are the age information and using the remaining age as the proxy for asset health, probability of failure or inability to be maintained due to obsolescence. These assumptions have been identified in POD24 and its associated model which we have reviewed in Appendix D.10.

### C.12.5.4 Benchmarking

The main inputs such as unit cost and expected asset life used by Aurora Energy for forecasting its renewal expenditure were benchmarked against industry peers.

The unit cost input for the replacement of protection schemes and relays differ depending on their function and Aurora Energy has used unit rates based on engineering estimates, taking account of recent

projects. We considered this to be consistent with the information contained within the independent review of Aurora Energy's pricebook.

Our analysis on benchmarking of the annual replacement rates proposed by Aurora Energy against peer businesses within the industry is presented in Appendix D. In summary, our analysis indicates Aurora Energy will be replacing at a uniform rate of 6% per annum over the CPP and review periods compared with two Australian industry peers that have replacement rates of 1.7% and 3.3%. Both of these organisations have had programs in place over the previous 10 years. Allowing for such a build-up or backlog of replacement works that probably should have been undertaken by this time, Aurora Energy's proposed rate of 6% over the CPP and review periods is not unreasonable.

We have used the annual replacement rate benchmarking with peers to form a view that the proposed level of expenditure is required to meet the safety need and to objectively verify that the ALARP (i.e. cost vs safety benefit) balance has been achieved with the proposed expenditure.

#### **C.12.5.5 Contingency factors**

No contingency factors have been included in this expenditure forecast.

#### **C.12.5.6 Interaction with other forecast expenditures**

This is a dedicated protection systems replacement program that has been in place since RY19. Protection schemes and relays involved in zone substation projects are included under Program R5. The expenditure for these protection schemes is also included within the individual zone substation projects and not included in this expenditure of this program.

There is a relationship between this program and the opex maintenance program; Preventive (O1), Corrective (O2) and Reactive (O3). An initial uplift in maintenance expenditure is being incurred due to increased maintenance frequencies on electromagnetic protection relays. A reduction in corrective and reactive maintenance will lag the expenditure in this program. This has been addressed within each of these respective programs.

#### **C.12.6 Deliverability**

Our observations on capex deliverability, in general, have been provided in section 4.5. The specialised skills required for protection systems testing and commissioning is limited in the industry. We are of the view that Aurora Energy has established sufficient service providers with the necessary skills set that are available and that have the ability to source additional technicians if required.

#### **C.12.7 Our finding**

We have reviewed all the inputs used to identify and estimate this expenditure forecast and we consider that they are reasonable. Our review of the asset replacement modelling and our findings are presented in section D.12.9.

#### **C.12.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on its proposed capex forecasts was largely sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

As set out in section C.2.1, the Commission may want to consider how Aurora Energy plans to develop asset performance measurements and risk-based models for its renewal programs over the CPP and review periods.

## C.13 ARROWTOWN 33 KV RING UPGRADE (C8)

Table C.19: Verification summary – Arrowtown 33 kV Ring upgrade (\$2020, million)

<b>Expenditure category</b>	Arrowtown 33 kV Ring upgrade	
<b>Aurora Energy CPP forecast</b>	CPP period: \$5.4 million Review period: \$5.4 million	
<b>Recommendation</b>	<b>Verified: *</b> CPP period: \$5.4 million Review period: \$5.4 million	<b>Unverified: *</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	Need for the project appears clear based on historical and forecast demand relative to firm capacity, subject to forecast demand being realised.  Focus on economic net benefit rather than deterministic security of supply standard is appropriate.  Estimated net benefit depends on assumptions, including VoLL, forecast demand, and discount rate, which do not appear inappropriate.	* Project net benefit depends on forecast demand, which will be affected by the COVID-19 pandemic – and so, this project may be a could be treated as a contingent project (e.g. with demand reaching a certain level the trigger)
<b>What needs to be done</b>	Consider updating the demand forecasts to incorporate the impact of the COVID-19 pandemic  If treated as contingent, then consider what trigger or triggers may be appropriate	
<b>Potential scope for improvement</b>	N/A	

### C.13.1 Project description

Central Otago is one of the fastest growing regions in New Zealand. One of the bulk supply points from Transpower to the Central Otago network is at Frankton GXP. From this point, a 33 kV ring is used to supply Arrowtown, Coronet Peak, Dalefield and the Remarkables, with back-feed capability should one section of the ring fail. The collective peak demand of these substations is 16.7 MVA, occurring during the RY20 winter peak. Load forecasting has projected significant growth in the area.

This project involves installing an additional 33 kV feeder circuit to increase the capacity of the Arrowtown 33 kV ring. This work is closely linked to another project to install a 33 kV switchboard at the Arrowtown zone substation. Together, the two projects would enable the Arrowtown 33 kV ring to be operated in a closed configuration.

### C.13.2 Cost estimate / expenditure forecast

Table C.20 shows the forecast expenditure during the CPP and review periods.

Table C.20: Forecast expenditure – Arrowtown Ring upgrade (\$2020, \$million)

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Expenditure	-	3.95	1.49	-	-	5.43	5.43

### C.13.3 Relevant policies and planning standards

Aurora Energy has developed an internal security of supply guidelines based on a review of other industry-standard guidelines from other EDBs. These guidelines are not considered binding but are used as a guide for decision making and options analysis for projects undertaken to meet an identified network need.

Figure C.8: Security of Supply Guidelines

Class	Description	Load (MW)	Cable, Line or Transformer Fault	Double Cable, Line, or Transformer Fault	Bus or switchgear fault
<b>GXP's</b>					
CBD/Urban	GXP's supplying predominantly metropolitan areas, CBDs and commercial or industrial customers	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Rural/Semi-Rural	GXP's supplying predominantly rural and semi-rural areas	15-60	No interruption	Restore within 4 hours	No interruption for 50% and restore remainder within 4 hours
<b>66 kV and 33 kV Sub-transmission Networks</b>					
Category Z1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	15 - 24	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Category Z2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-15	Restore within 2 hours (may include use of the mobile substation)	Restore 75% within 2 hours and remainder in repair time	Restore within 2 hours
Category Z3	Predominantly rural and semi-rural areas	0-15	Restore within 4 hours (may include use of mobile substation)	Restore in repair time	Restore in repair time
<b>6.6 kV and 11 kV Network</b>					
Category F1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	1-4	Restore all but 1 MVA within 2 hours, remainder in repair time <sup>1</sup>	Restore in repair time	Restore all but 1 MVA within 2 hours, remainder in 4 hours (using a generator)
Category F2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-1	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>
Category F3	Predominantly rural and semi-rural areas	1-4	Restore all but 1 MVA within 4 hours, remainder in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore all but 1 MVA within 4 hours, remainder in repair time <sup>1</sup>
Category F4	Predominantly rural and semi-rural areas	0-1	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>

Note 1: Generators to be used where feasible to enable restoration of power before the fault is repaired.

Source: Aurora Energy.

### C.13.4 Information provided

Table C.21 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.21: Information provided

Title	Reference	Date
POD31 - Arrowtown 33kV Ring Upgrade	E-11	21 February 2020
MOD31 - Arrowtown 33kV Ring Upgrade - Customised Estimate	E-9	21 February 2020
MOD31 - Arrowtown 33kV Ring Upgrade - Economic Evaluation	E-10	21 February 2020

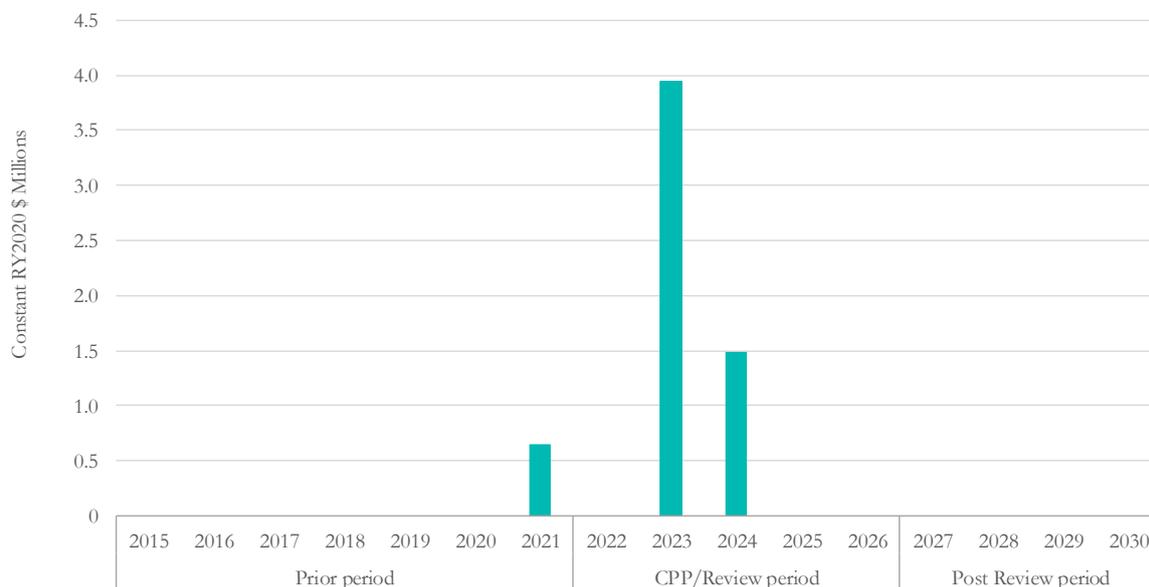
Title	Reference	Date
Aurora VoLL report FINAL	E-75	6 March 2020
P09 - Growth - Arrowtown	V-137	28 March 2020
<b>Provided in response to our draft report</b>		
Arrowtown 33kV Ring Partial Prudent Forecast (RY20 to RY23)	PR-8	22 April 2020
200426 VOLL note	PR-30	26 April 2020

### C.13.5 Assessment of forecast method used

#### C.13.5.1 Expenditure trends

Figure C.9 shows the expected and forecast expenditure for the Arrowtown 33 kV ring upgrade project. The expenditure is based on a project estimate using the standard building block unit rates that also support the asset renewal programs. The project cost estimate was allocated on percentage basis over RY23 to RY24. The spend estimated for the period prior to the CPP and review periods reflects some initial preparatory works undertaken by Aurora Energy in RY21, including engaging with relevant authorities.

Figure C.9: Arrowtown Ring upgrade – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

The project started in RY20 with planning and discussions about the preferred route for the cable run over the Shotover River commenced with the appropriate authorities. Most of the construction work is scheduled in RY23, due to the potential impact of the COVID-19 pandemic on expected load on the Arrowtown ring.

The post contingent capacity is based on the line/cable capacity where either the northern or southern leg would back feed the out-of-service leg. The load at risk is the load aggregation of the zone substation

connected to each leg, adjusted for diversity to recognise that zone substations peak at different times. The outage rates are based on historical Aurora Energy information where available and are also sourced from the EEA security of supply guidelines.

Figure C.10 shows the average and maximum daily 5-minute MW readings for the Arrowtown 33 kV ring for the June to August 2019 period (covering the winter peak). The N-1 firm capacity for the ring is shown as 13 MVA (the dotted line). The figure shows that current demand for the ring breaches the 13 MVA capacity limit at least some of the time. Closer examination suggests that this occurred in 8.7% of the 5-minute intervals over the three-month period.

Figure C.10: Arrowtown 33 kV ring – June to August 2019 – 5-minute Maximum Demand (MW)



Source: Aurora Energy data.

The nature of load is very seasonal; with the average values being approximately 64% of the daily maximum demand during the June to August 2019 period and the pattern of daily usage being fairly consistent over that period. Given that the Arrowtown 33 kV ring peaks during this winter period, it is likely that the load profile for other times of the year are lower than that shown above. Aurora Energy projects that maximum demand will steadily increase from 16.7MW in RY20 by approximately 0.3 MVA per year to RY24, further increasing demand above the N-1 firm capacity.

Aurora Energy does not consider the security of supply guidelines are to be enforced as a strict requirement for the security of supply, but more as a guidance for level of redundancy or switching to be available in the event of an outage. The decision to proceed with a project is based more on the economic analysis including whole-of-life costing, with other considerations such as designated security of supply considered more as supporting argument.

### C.13.5.2 Expenditure justification

The Arrowtown 33 kV ring is classified as Z1 under the Security of Supply Guidelines, suggesting that an N-1 supply arrangement is preferred.

Aurora Energy has stated that the project cannot be deferred because of the known excessive line loads and capacity constraints of the ring, and that the firm capacity of the northern leg is currently exceeded. Aurora Energy forecasts that the load on this part of the ring is forecast to continue to increase.

There is a switch at the Arrowtown substation that is currently kept in an open state so as to isolate the two sides of the 33 kV ring. This switch and line switches enable on site restoration of supply in the event of an outage. Aurora Energy staff advised us that remote or automated switching is not possible with the current hardware and SCADA data.

In our view, there is a clear need to address the network constraints as load on the northern leg is well in excess of the firm capacity of the Arrowtown substation to meet in the event of a fault. However, although the proposed solution does appear to be the best option in terms of an engineering solution, the economic benefits for the project are only marginal based on the modelling assumptions adopted by Aurora Energy, and become negative if the VoLL assumption is updated to reflect that included with its quality standard variation (see discussion below).

Aurora Energy considers that the existing capacity and security constraint of the ring breaches its security of supply guidelines – and has done so since 2014. Aurora Energy assessed the risk of delaying the augmentation work and considered the net benefit from the project was maximised if it was executed as soon as possible.

### C.13.5.3 Key assumptions used

#### VoLL

Aurora Energy used a VoLL assumption of \$27,136 per MWh based on the values used by Transpower for the RY21 to RY25 period.<sup>148</sup> Although provided with an alternative – and lower estimate – of \$16,468 per MWh by PwC,<sup>149</sup> Aurora Energy has adopted the higher figure for both its economic evaluation of the Arrowtown 33 kV ring upgrade project and the quality incentive scheme.

Aurora Energy considered the higher value more appropriate because:<sup>150</sup>

- *Transpower's approach is both comprehensive and inclusive combining three separate studies.*
- *The survey size on Transpower's report is significant with all consumer types represented and hence statistically accurate.*
- *There is a wide variation in VoLL values between consumer types in each territorial area in the Aurora PwC report. This is noted in their study where some business consumers provided values lower than the Electricity Authority's 2013 estimate.*

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<sup>148</sup> The \$27,136 was based on a PwC report done for Transpower in 2018. This is the average of the Aurora Energy GXPs, inflated to RY20 terms.

<sup>149</sup> This lower figure was provided by PwC in: PwC, *Estimating the Value of Lost Load, Report on the value of network reliability*, January 2018.

<sup>150</sup> Aurora Energy, *Assessment of Aurora Energy VoLL*, 26 April 2020, p. 1.

- *Further, the sample size in the Aurora survey was smaller in the non-residential categories and the residential group was overrepresented by +70yo retirees.*
- *The wide range of residential VOLL values between Dunedin and Central (and the national survey) is not intuitive and we would want to better understand the logic/reasons for this difference before applying to our investment decision making*
- *We note that there are a significant number of rented holiday homes in Central and more work is required to understand how to take this into account when undertaking a survey of this nature.*

In our view, Aurora Energy's justification for adopting the Transpower estimate appears reasonable, including because that estimate is consistent with the Commission's most recent DPP determination.

Nevertheless, the noticeable difference between the two estimates may warrant further investigation, especially given the impact on the estimated net benefits from the project. For instance, adopting the lower figure, reduces the NPV of the preferred option from \$0.7 million to negative \$1.6 million.<sup>151</sup> We have not investigated these differences further.

### **Demand forecast**

As discussed in section 6.2, Aurora Energy has largely relied on historical peak demand trends to forecast future peak demands, with forecast changes in GDP and dwellings used as a predictor for some zone substations. This does not factor in the impact from the COVID-19 pandemic.

Although those forecasts suffer from some limitations, this is not unsurprising as to some degree all forecasts do. The key is ensuring that these are validated before being used to inform investment decisions. Aurora Energy explained that it has done this, albeit before the pandemic was in full flight.<sup>152</sup>

Of course, the key shortcoming of the demand forecasts is that they do not factor in the impact of the COVID-19 pandemic – which is likely to have a meaningful impact on demand in the area. The Arrowsmith ring area relies heavily on tourism (especially in winter), which is likely to be depressed for while travel restrictions remain in place and due to an expected economic recession, at least in the short term.

For this reason, the *timing* for the project appears contingent on demand rebounding to the levels forecast by Aurora Energy before the pandemic took hold. Consistently, Aurora Energy recently advised us that it now considers all:<sup>153</sup>

*growth-related projects/programmes have sufficient uncertainty to be considered contingent projects at this time.*

We agree and recommend that the Commission engage further with Aurora Energy on how best to recognise this in the CPP determination.<sup>154</sup>

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<sup>151</sup> This is calculated by replacing the \$27,136 per MWh figure with \$17,875 per MWh, being the \$16,468 per MWh updated for inflation.

<sup>152</sup> Aurora Energy provided its demand forecasts to us at the end of January 2020.

<sup>153</sup> Aurora Energy, Memo from Glenn Coates to Eli Grace-Webb, *Response to follow up questions prompted by Commission feedback*, 12 May 2020, p. 2.

<sup>154</sup> For instance, we understand that the current IM include specific expenditure thresholds before a project would meet the definition of 'contingent project'. We also understand that the IM can be amended for a specific CPP determination. We consider it outside of our verification scope to provide a view on such amendments.

One potential shortcoming of relying on peak demand forecasts is that they represent a peak, that in some cases could only be reached very few times in a year. Even if technically an N-1 security of supply level is breached at those times, it does not necessarily make it appropriate to undertake significant investment to address that issue. This highlights the importance of using a probabilistic approach to assess the likelihood and consequence of potential reliability-driven faults on the network.

### **Discount rate**

Aurora Energy used a real, pre-tax discount rate of 6% to calculate the present value of projected costs and benefits – a value sourced from New Zealand Treasury for infrastructure projects.<sup>155</sup> Although this value does not match the regulated rate of return allowed by the Commission, it is not unreasonable to rely on a discount rate advised by New Zealand Treasury for infrastructure projects.

One concern is that the discount rate was last updated in May 2018 when market conditions were quite different. It is likely that the COVID-19 pandemic and the likely economic impact will have affected forward-looking financing costs. This is relevant because the estimated net benefits are quite sensitive to the assumed discount rate. Increasing the discount rate to 7.5%, for instance, leads to a negative NPV for the preferred option.

### **C.13.5.4 Benchmarking**

Aurora Energy has benchmarked the failure rates of equipment with other EDBs where data was available to ensure the failure rates used in the analysis were reasonable.

### **C.13.5.5 Contingency factors**

No specific contingency factors have been allowed for.

### **C.13.5.6 Interaction with other forecast expenditures**

Along with the Arrowtown 33 kV ring upgrade, Aurora Energy is also proposing Arrowtown zone substation 33 kV indoor switchboard project. Benefits from both projects are somewhat contingent on each other. We have not reviewed the switchboard project.

### **C.13.6 Deliverability**

The preferred option involves an underground cable installed in a road reserve and is not expected to attract significant opposition from the public, residents or landowners. The most significant risk to deliverability is the ducts to be installed across the Shotover River bridge.

Aurora Energy has had initial discussions with QLDC and NZTA and good progress has been made. Aurora Energy does have an overhead river crossing solution as an alternative if required. However, given the impact of the COVID-19 pandemic, these options may need to be reconsidered in due course.

The project will be constructed using an external contractor, following a tender process. This process can be used to mitigate delivery risks for other aspects of the project.

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<sup>155</sup> See: <https://treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates>, accessed 6 April 2020.

### C.13.7 Our finding

In our view, Aurora Energy's expenditure forecast for the Arrowtown 33 kV ring upgrade project over the CPP and review periods does appear to satisfy the expenditure objective, *if* the demand forecast that underpins it is realised. Given the impact of COVID-19, the project should also be considered as a contingent project.

Our view is based on the following observations:

- the need for the project is apparent *if* forecast demand is realised, with the loads on the northern leg of the ring well in excess of N-1 security level, and have been for several years – the projected growth in the area will only continue to put load at risk
- the COVID-19 pandemic will almost certainly reduce demand on the Arrowtown 33 kV ring, but it is unclear by how much and for how long – as such, the *timing* for the project should be contingent on a given level of demand being realised<sup>156</sup>
- Aurora Energy's security of supply guidelines appear to have been followed when assessing the project need and potential options – although the N-1 security of supply standard recommend for the ring given its rating, we understand that this was only used as a guide rather than deterministic requirement<sup>157</sup>
- the project cost estimate is consistent with Aurora Energy's price book and does not appear inappropriate
- the VoLL used to assess the economic benefits of the preferred option are consistent with that adopted by the Commission in its recent DPP determination and proposed by Aurora Energy for the quality incentive scheme.

Based on these findings we consider the Arrowtown 33 kV ring upgrade capex of \$5.4 million for the review period is verified. We also consider that the full \$5.4 million could be considered a contingent project given that the demand projections that underpin the economic assessment for it will likely be affected by the COVID-19 pandemic.

Our finding is subject to the following limitations:

- the economic evaluation is based on several assumptions, such as the discount rate, forecast demand, and load at risk parameters (as well as VoLL) – changes to these assumptions can materially affect the estimated net benefit from the project, and therefore conclusions about them
- although this project relates to the Arrowtown zone substation 33 kV indoor switchboard project, we have not reviewed the interaction with that project – it may be that interdependencies between the two projects justify both or neither being pursued.

### C.13.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on Arrowtown 33 kV ring upgrade project was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

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<sup>156</sup> Although we have not identified a specific demand level, one could be set at a level the results in the estimated NPV from the project being positive.

<sup>157</sup> While an N-1 supply standard as defined in this guideline appears to be common practice in New Zealand, it is inconsistent with many overseas jurisdictions that adopt a probabilistic standard that seeks to minimise supply loss risk against the investment cost. An N-1 deterministic standard often leads to earlier augmentation; and hence higher remediation costs than if the standard allowed some energy to be placed at risk of loss.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether the demand forecast for the Arrowtown 33 kV ring should be updated to reflect the expected impact of the COVID-19 pandemic once more information is known (i.e. closer to when the Commission makes its CPP determination)
- what trigger or triggers should be used if the project is treated as a contingent project, noting that demand at a certain level is an obvious candidate
- what VoLL estimate should be used to value the reliability benefits from the project, including whether it is more appropriate to use a value based on Aurora Energy's consumers rather than New Zealand consumers more generally
- whether, in addition to reliability, there are other benefits that come from the project that are not yet captured in the economic evaluation
- whether the 6% discount rate is appropriate given it differs from the regulated rate of return adopted by the Commission and may not reflect more recent market information
- if the project does go ahead, how best to monitor that the project is delivered efficiently.

## C.14 RIVERBANK UPGRADE (C9)

Table C.22: Verification summary – Riverbank upgrade (\$2020, \$million)

<b>Expenditure category</b>	Riverbank Substation upgrade	
<b>Aurora Energy CPP forecast</b>	CPP period: \$0 million Review period: \$0 million* * After releasing our draft report, Aurora Energy proposed deferring it until after the review period. We have retained our assessment of it below.	
<b>Recommendation</b>	<b>Verified: *</b> CPP period: \$0 million Review period: \$0 million	<b>Unverified: *</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	Focus on economic net benefit rather than deterministic security of supply standard is appropriate. Estimated net benefit depends on assumptions, including VoLL, forecast demand, and discount rate, which do not appear inappropriate.	* Original project has now been deferred to the post review period, as a consequence of the impacts of the COVID-19 pandemic. Increased uncertainty in load forecasts does not justify project during the review period. Much like the Arrowtown 33 kV ring upgrade project, the Riverbank substation upgrade project net benefit depends on forecast demand, which will be affected by the COVID-19 pandemic – and so, this project may be a could be treated as a contingent project (e.g. with demand reaching a certain level the trigger) Not clear that all viable options have been considered
<b>What needs to be done</b>	Consider updating the demand forecasts to incorporate the impact of the COVID-19 pandemic. If treated as contingent, then consider what trigger or triggers may be appropriate.	
<b>Potential scope for improvement</b>	Revisit option list to consider nature of projected demand and include consideration of other alternatives including potential short overload of transformers and possible use of mobile substation to defer expenditure beyond review period	

### C.14.1 Project description

Wanaka is a ski and summer resort town in Central Otago with a local economy that is reliant upon the tourism industry. There has been significant growth in demand in recent years. The risks associated with an outage affecting the Wanaka load are reputational for Aurora Energy, where inconvenience to local businesses and consumers – particularly in the winter periods – would pose a significant problem.

The Wanaka zone substation supplies Wanaka and the surrounding areas, with two 24 MVA power transformers and an 11 kV indoor switchboard. The load is categorised as Z1 by Aurora Energy – meaning that consumers should not experience any interruption for a fault on a single cable, line or transformer (also known as an N-1 security of supply). Total demand on the substation was 22 MW for the RY20 winter peak and is forecast to exceed the firm capacity of 24 MVA by around RY25.

The project involves installing a 66/11 kV 24 MVA transformer and associated switchgear at the Riverbank switching station – converting it to a zone substation – to offload the Wanaka zone substation and maintain the required security of supply level.

### C.14.2 Cost estimate / expenditure forecast

Table C.23 shows the forecast expenditure during the CPP and review periods. As shown, no expenditure was originally forecast for the CPP period. As a result of the impacts of the COVID-19 pandemic, the uncertainty in expected growth in load demand is higher and the project has been deferred to a forecast start in RY27, which is outside the review period.

**Table C.23: Forecast expenditure – Riverbank upgrade (\$2020, million)**

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Original Expenditure	-	-	-	1.20	2.81	0.00	4.01
Revised Expenditure	-	-	-	-	-	0.00	0.00

### C.14.3 Relevant policies and planning standards

Aurora Energy has developed an internal security of supply guidelines based on a review of other industry-standard guidelines from other EDBs. These guidelines are not considered binding but are used as a guide for decision making and options analysis for projects undertaken to meet an identified network need.

Figure C.11: Security of Supply Guidelines

Class	Description	Load (MW)	Cable, Line or Transformer Fault	Double Cable, Line, or Transformer Fault	Bus or switchgear fault
<b>GXPs</b>					
CBD/Urban	GXPs supplying predominantly metropolitan areas, CBDs and commercial or industrial customers	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Rural/Semi-Rural	GXPs supplying predominantly rural and semi-rural areas	15-60	No interruption	Restore within 4 hours	No interruption for 50% and restore remainder within 4 hours
<b>66 kV and 33 kV Sub-transmission Networks</b>					
Category Z1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	15 - 24	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Category Z2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-15	Restore within 2 hours (may include use of the mobile substation)	Restore 75% within 2 hours and remainder in repair time	Restore within 2 hours
Category Z3	Predominantly rural and semi-rural areas	0-15	Restore within 4 hours (may include use of mobile substation)	Restore in repair time	Restore in repair time
<b>6.6 kV and 11 kV Network</b>					
Category F1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	1-4	Restore all but 1 MVA within 2 hours, remainder in repair time <sup>1</sup>	Restore in repair time	Restore all but 1 MVA within 2 hours, remainder in 4 hours (using a generator)
Category F2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-1	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>
Category F3	Predominantly rural and semi-rural areas	1-4	Restore all but 1 MVA within 4 hours, remainder in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore all but 1 MVA within 4 hours, remainder in repair time <sup>1</sup>
Category F4	Predominantly rural and semi-rural areas	0-1	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>	Restore in repair time <sup>1</sup>

Note 1: Generators to be used where feasible to enable restoration of power before the fault is repaired.

Source: Aurora Energy data.

## C.14.4 Information provided

Table C.24 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.24: Information provided

Title	Reference	Date
POD34 - Riverbank Zone Substation Upgrade   Portfolio Overview Document	E-22	27 February 2020
MOD34 - Riverbank Zone Substation Upgrade - Customised Estimate	E-20	27 February 2020
MOD34 - Riverbank Zone Substation Upgrade - Economic Evaluation	E-21	27 February 2020
P10 - Growth - Riverbank presentation	V-138	28 March 2020
<b>Provided in response to our draft report</b>		
200426 VOLL note	PR-30	26 April 2020

## C.14.5 Assessment of forecast method used

### C.14.5.1 Expenditure trends

The expenditure is based on a project estimate using the standard building block unit rates that also support the asset renewal programs.

The need for this augmentation was under constant review, being based on a longer term forecast of projected increases in load in the Wanaka area. Due to the anticipated impact of the COVID-19 pandemic on that load, Aurora Energy has deferred the project beyond the review period. The construction schedule from RY27 has been profiled to allow for a steady resource build up.

#### C.14.5.2 Expenditure justification

Current demand forecasting suggests load at the Wanaka substation will breach its 24 MVA capacity limit for N-1 supply in RY25.

On the long-list of options, Aurora Energy appraised seven potential options – three network, and four non-network options – against criteria that align with to its asset management policy. Aurora Energy has relied upon its security of supply guidelines when identifying the need for the project to satisfy a network constraint (refer section C.13). Under these guidelines, the Wanaka load is classified as Z1 – which indicates that the 24 MVA load should have an N-1 security requirement.

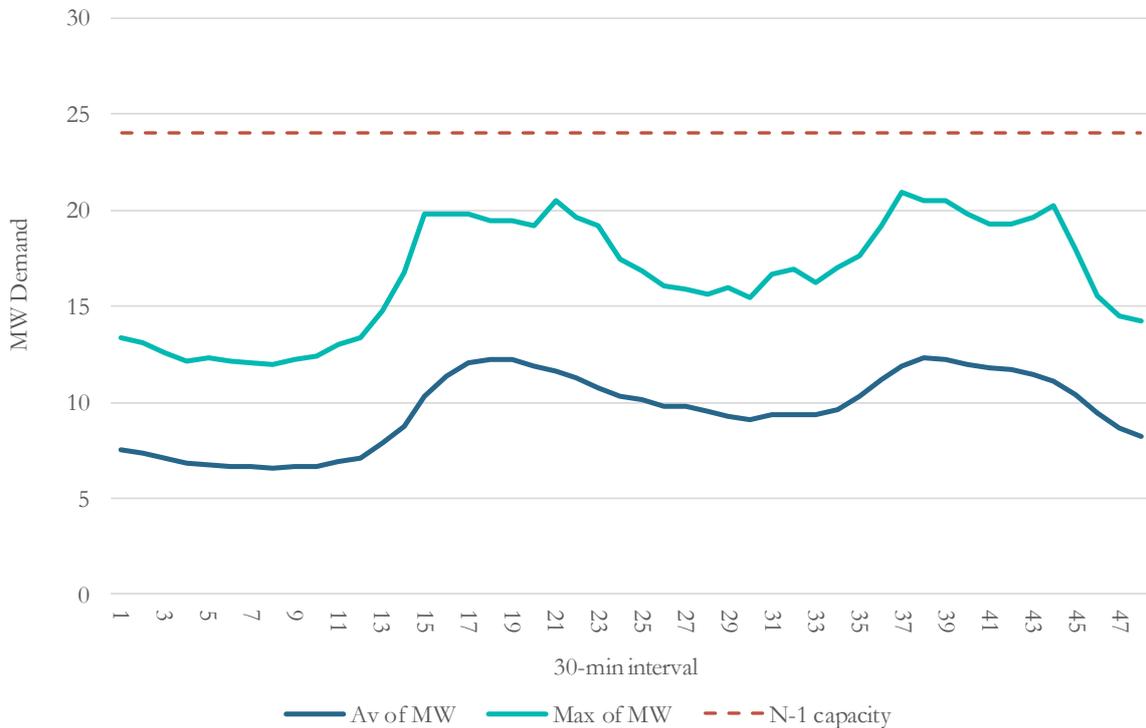
Constructing a new switch bay in the Riverbank switching station is only viable with additional 11 kV switching. Therefore, to maintain N-1 supply for load connected to Riverbank under the preferred option, the existing Wanaka feeder, WK2752, will be connected to Riverbank zone substation feeder four – becoming the express feeder to Wanaka zone substation. This connection allows load to transfer from Riverbank to Wanaka.

Although relevant options were identified, it does not appear that all of those identified were appropriate and some options – such as short-term options that could efficiently defer the project spend – were not included. For instance, procuring a spare transformer does not appear to be a viable option.

Moreover, given the types of business in the Wanaka area, the demand forecast shown in POD34 appears insufficient to identify if the projected increase in demand is seasonal or only during particular parts of the day. A better understanding of the load pattern would make it easier to assess whether the increase in load could be handled with short-term transformer overload or through use of a mobile substation (5MVA).

Figure C.12 shows the average and maximum daily 30-minute MW readings for the Wanaka substation for the period 2018/2019. The N-1 firm capacity for the existing Wanaka substation is shown as 24 MVA (the dotted line). Aurora Energy's demand forecasting suggests load at Wanaka Substation will breach the 24 MVA capacity limit of the substation for N-1 supply in 2025 (although this does not include the potential impact of the COVID-19 pandemic)..

Figure C.12: Wanaka Substation – 2018/2019 30-minute Maximum Demand (MW)



Source: Aurora Energy data.

The nature of load is very seasonal; with the average values being approximately 57% of the daily maximum demand and the pattern of daily usage being fairly consistent during the year. Added to this, Aurora Energy projects that maximum demand will steadily increase from 21MW in RY19 by approximately 0.5–0.6 MVA per year, breaching the N-1 firm capacity in RY25.

As with the Arrowtown 33 kV ring upgrade project discussed above, Aurora Energy does not consider the security of supply guidelines are to be enforced as a strict requirement for the security of supply, but more as a guidance for level of redundancy or switching to be available in the event of an outage. The decision to proceed with a project is based more on the economic analysis including whole-of-life costing, with other considerations such as designated security of supply considered more as supporting argument.

### C.14.5.3 Key assumptions used

#### VoLL

As with the Arrowtown 33 kV ring upgrade project, Aurora Energy used a VoLL assumption of \$27,136 per MWh based on the values used by Transpower for the RY21 to RY25 period.<sup>158</sup> Although provided with an alternative – and lower estimate – of \$16,468 per MWh by PwC,<sup>159</sup> Aurora Energy has adopted the higher figure for both its economic evaluation of the Arrowtown 33 kV ring upgrade project and the quality incentive scheme.

<sup>158</sup> The \$27,136 was based on a PwC report done for Transpower in 2018. This is the average of the Aurora Energy GXPs, inflated to RY20 terms.

<sup>159</sup> This lower figure was provided by PwC in: PwC, *Estimating the Value of Lost Load, Report on the value of network reliability*, January 2018.

Aurora Energy considered the higher value more appropriate because:<sup>160</sup>

- *Transpower’s approach is both comprehensive and inclusive combining three separate studies.*
- *The survey size on Transpower’s report is significant with all consumer types represented and hence statistically accurate.*
- *There is a wide variation in VoLL values between consumer types in each territorial area in the Aurora PwC report. This is noted in their study where some business consumers provided values lower than the Electricity Authority’s 2013 estimate.*
- *Further, the sample size in the Aurora survey was smaller in the non-residential categories and the residential group was overrepresented by +70yo retirees.*
- *The wide range of residential VOLL values between Dunedin and Central (and the national survey) is not intuitive and we would want to better understand the logic/reasons for this difference before applying to our investment decision making*
- *We note that there are a significant number of rented holiday homes in Central and more work is required to understand how to take this into account when undertaking a survey of this nature.*

In our view, Aurora Energy’s justification for adopting the Transpower estimate appears reasonable, including because that estimate is consistent with the Commission’s most recent DPP determination.

Nevertheless, the noticeable difference between the two estimates may warrant further investigation, especially given the impact on the estimated net benefits from the project. For instance, adopting the lower figure, reduces the NPV of the preferred option from \$0.3 million to negative \$0.8 million.<sup>161</sup> We have not investigated these differences further.

### **Demand forecast**

The project need is based on the expected maximum demand forecast for Wanaka zone substation increasing beyond 24 MVA in RY25 – which, if realised, will exceed the substation’s current firm capacity and the rating of the 11 kV switchboard.

As discussed in section 6.2, Aurora Energy has largely relied on historical peak demand trends to forecast future peak demands. Although some demand forecasts factored in forecast changes in GDP and dwellings, this was not the case for the Wanaka zone substation. This does not factor in the impact from the COVID-19 pandemic.

Although those forecasts suffer from some limitations, this is not unsurprising as to some degree all forecasts do. The key is ensuring that these are validated to some degree before being used to inform investment decisions. Aurora Energy explained that it has done this. Based on our understanding of the area, some growth would be expected. However, given that forecast accuracy declines the further into the future that they apply, some caution is needed before basing investment decisions on such forecasts.

As with the Arrowtown 33 kV ring upgrade project, the key shortcoming of the demand forecasts is that they do not factor in the impact of the COVID-19 pandemic – which is likely to have a meaningful

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<sup>160</sup> Aurora Energy, *Assessment of Aurora Energy VoLL*, 26 April 2020, p. 1.

<sup>161</sup> This is calculated by replacing the \$27,136 per MWh figure with \$17,875 per MWh, being the \$16,468 per MWh updated for inflation.

impact on demand in the area. The Wanaka area relies heavily on tourism, which is likely to be depressed while travel restrictions remain in place and due to expected economic recession, at least in the short term.

For this reason, the *timing* for the project appears contingent on demand rebounding to the levels forecast by Aurora Energy before the pandemic took hold. Consistently, Aurora Energy recently advised us that it now considers all:<sup>162</sup>

*growth-related projects/programmes have sufficient uncertainty to be considered contingent projects at this time.*

We agree and recommend that the Commission engage further with Aurora Energy on how best to recognise this in the CPP determination.<sup>163</sup>

As discussed above, one limitation of relying on peak demand forecasts is that they represent a peak, that in some cases could only be reached very few times in a year. Even if technically an N-1 security of supply level is breached at those times, it does not necessarily make it appropriate to undertake significant investment to address that issue. This highlights the importance of using a probabilistic approach to assess the likelihood and consequence of potential reliability-driven faults on the network.

#### **Discount rate**

Aurora Energy used a real, pre-tax discount rate of 6% to calculate the present value of projected costs and benefits – a value sourced from New Zealand Treasury for infrastructure projects.<sup>164</sup> Although this value does not match the regulated rate of return allowed by the Commission, it is not unreasonable to rely on a discount rate advised by New Zealand Treasury for infrastructure projects.

As per the Arrowtown 33 kV ring upgrade project, one concern is that the discount rate was last updated in May 2018 when market conditions were quite different. It is likely that the COVID-19 pandemic and the likely economic impact will have affected forward-looking financing costs. This is relevant because the estimated net benefits are quite sensitive to the assumed discount rate. Increasing the discount rate to 7.5%, for instance, leads to a negative NPV for the preferred option.

#### **C.14.5.4 Benchmarking**

Aurora Energy has benchmarked the failure rates of equipment with other EDBs where data was available to ensure the failure rates used in the analysis were reasonable.

#### **C.14.5.5 Contingency factors**

No specific contingency factors have been allowed for.

#### **C.14.5.6 Interaction with other forecast expenditures**

There are no interactions with other forecast expenditures that we are aware of.

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<sup>162</sup> Aurora Energy, Memo from Glenn Coates to Eli Grace-Webb, *Response to follow up questions prompted by Commission feedback*, 12 May 2020, p. 2.

<sup>163</sup> For instance, we understand that the current IM include specific expenditure thresholds before a project would meet the definition of ‘contingent project’. We also understand that the IM can be amended for a specific CPP determination. We consider it outside of our verification scope to provide a view on such amendments.

<sup>164</sup> See: <https://treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates>, accessed 6 April 2020.

### C.14.6 Deliverability

Given the proposed timing of the project, we do not envisage any significant deliverability concerns at this stage that Aurora Energy could not manage effectively, especially given that its asset management systems and project management capability will be significantly improved by then.

The timing for this project is largely driven by the identified need for additional supply by RY24, which is based on Aurora Energy's current demand forecast and advice regarding potential load growth projects in the area. Aurora Energy had already deferred the project start to RY24 to support a steady resource profile across all of the other large projects on the network.

### C.14.7 Our finding

As Aurora Energy no longer proposes to undertake the Riverbank zone substation upgrade project over the CPP or review periods, we have not provided a view on whether it satisfies the expenditure objective. Our draft position was that it did not. However, as with the Arrowtown 33 kV ring upgrade project, the project should nevertheless be considered as a contingent project.

Our view is based on the following observations:

- the proposed timing for the project is not yet justified based on the information available – even if peak demand continues to grow around Wanaka at historical rates, it is not clear that the risk of lost load will be sufficient to justify investment in the timeframes proposed
- Aurora Energy's security of supply guidelines appear to have been followed when assessing the project need and potential options – although the N-1 security of supply standard recommend for the Wanaka substation given its rating, we understand that this was only used as a guide rather than deterministic requirement<sup>165</sup>
- the project cost estimate is consistent with Aurora Energy's price book and does not appear inappropriate
- Aurora Energy does not appear to have considered short-term options that could be used to defer the need for more substantial investment over the review period – more detailed assessment of the load and the likely nature of the projected growth may support other options for mitigating the potential impact from the load increase
- the VoLL used to assess the economic benefits of the preferred option are consistent with that adopted by the Commission in its recent DPP determination and proposed by Aurora Energy for the quality incentive scheme.

Our finding is subject to the following limitations:

- the demand forecasts are particularly uncertain, especially given the impact that events like the COVID-19 pandemic may have on tourism in the region – if actual demand does increase significantly in future years, then it may be there the project becomes justified on economic grounds
- the economic evaluation is based on several assumptions, such as the discount rate, forecast demand, and load at risk parameters (as well as VoLL) – changes to these assumptions can materially affect the estimated net benefit from the project, and therefore conclusions about them

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<sup>165</sup> While an N-1 supply standard as defined in this guideline appears to be common practice in New Zealand, it is inconsistent with many overseas jurisdictions that adopt a probabilistic standard that seeks to minimise supply loss risk against the investment cost. An N-1 deterministic standard often leads to earlier augmentation; and hence higher remediation costs than if the standard allowed some energy to be placed at risk of loss.

- although the project may appear uneconomic to undertake at this stage, it could become economic in the future once further information is available about actual demand growth in the Wanaka area or if the VoLL changes.

#### C.14.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on Riverbank zone substation upgrade project was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

Similar to the Arrowtown 33 kV ring upgrade project, when undertaking its own assessment of the information for this project (if it remains relevant), the Commission may want to consider:

- whether the demand forecast for the Wanaka zone substation should be updated to reflect the expected impact of the COVID-19 pandemic once more information is known (i.e. closer to when the Commission makes its CPP determination)
- what trigger or triggers should be used if the project is treated as a contingent project, noting that demand at a certain level is an obvious candidate
- what the VoLL should be used to value the reliability benefits from the project, including whether it is more appropriate to use a value based on Aurora Energy's consumers rather than New Zealand consumers more generally
- the reliability of the demand forecasts and whether more recent information increases or decreases the need for the project during the review period
- whether, in addition to reliability, there are other benefits that come from the project that are not yet captured in the economic evaluation
- whether the 6% discount rate is appropriate given it differs from the regulated rate of return adopted by the Commission and may not reflect more recent market information
- if the project does go ahead, how best to monitor that the project is delivered efficiently.

## C.15 CONSUMER CONNECTIONS (C10)

Table C.25: Verification summary – Consumer connections (\$2020, \$millions)

<b>Expenditure category</b>	Other network capex – Consumer Connections	
<b>Aurora Energy CPP forecast</b>	<p>CPP period: \$11.4 million*</p> <p>Review period: \$22.6 million*</p> <p>* These values are net of capital contributions, which Aurora Energy assumes makes up 60% of gross connection and asset relocation expenditure</p>	
<b>Recommendation</b>	<p><b>Verified: **</b></p> <p>CPP period: \$11.4 million</p> <p>Review period: \$22.6 million</p>	<p><b>Unverified: **</b></p> <p>CPP period: \$0 million</p> <p>Review period: \$0 million</p>
<b>Expenditure outcome assessment</b>	<p>Although we have different views about some inputs and methods used to forecast net connection expenditure, these largely offset each other.</p> <p>Forecast net connection expenditure is consistent with historical expenditure and has been adjusted down by 25% over the RY22 and RY23 due to reflect the potential impact of the COVID-19 pandemic, which is not unreasonable.</p> <p>The build-up of the customised estimate for the major tourism operator’s connection upgrade is based on conceptual or high-level assumptions about feeder route, site selection, building size, and equipment configuration. We are unable verify the reasonableness of this assumed scope of capital asset given the contingent nature of this project.</p>	<p>** Need for the major tourism operator’s connection upgrade is contingent on the operator requesting a connection upgrade – the timing of which may be affected by the COVID-19 pandemic. As such, this component of the connection expenditure forecast (\$2.1 million over the review period) could be treated as a contingent project (e.g. with receiving such a request being the trigger)</p>
<b>What needs to be done</b>	If the major tourism operator’s connection upgrade is treated as contingent, then consider what trigger or triggers may be appropriate	
<b>Potential scope for improvement</b>	Support the customised cost estimate for the major tourism operator’s connection upgrade project by preparing a project feasibility and business case that shows single line diagrams, feeder routes etc. that incorporates Aurora Energy’s network design standard and client negotiation. We would anticipate such work occurring only once a connection upgrade is required or there is sufficient certainty that it will be.	

### C.15.1 Project description

The consumer connection portfolio includes expenditure on assets where the primary driver is the establishment of a new customer connection point or an alteration to an existing customer connection point. This includes expenditure on connection assets and/or parts of the network for which the expenditure is recoverable in total – or in part – by a contribution from the customer requesting a new or altered connection point. All consumer connections require that customers make a capital contribution as outlined in Aurora Energy’s capital contributions policy.

In recent years, Aurora Energy has on average connected approximately 1,000 residential homes and businesses to its network each year. New connections range from a single new house through to a range of businesses and infrastructure. In these years, Aurora Energy has been able to secure 45% contribution on average from the connection proponents.

Aurora Energy has determined the recent historical annual average expenditure level and assumed that this remains constant, in real terms, over the CPP and review periods. It has then added expected connection costs for a major tourism operator’s connection upgrade and assumed it will secure 60% capital contribution from the connection proponent, on average.

### C.15.2 Cost estimate / expenditure forecast

Table C.26 shows the forecast expenditure during the CPP and review periods for the customer connection. Expenditure is projected to be depressed in RY22 and RY23 at \$3.4 million per year due to the impact of the COVID-19 pandemic, before stepping up to the historical average of \$4.5 million in RY24, and up to \$5.2 million and \$6.0 million into RY25 and RY26, respectively, to cover the expected cost of the major tourism operator’s connection upgrade.

Table C.26: Forecast expenditure – customer connections net of contributions (\$2020, \$thousands)

Item	RY22	RY23	RY24	RY25	RY26	3-year total	5-year total
<b>Gross expenditure</b>							
Base	11,365	11,365	11,365	11,365	11,365	34,096	56,827
Major tourism operator’s connection upgrade	-	-	-	1,570	3,663	-	5,233
Less COVID-19 reductions	(2,841)	(2,841)	-	-	-	(5,683)	(5,683)
<b>Total</b>	<b>8,524</b>	<b>8,524</b>	<b>11,365</b>	<b>12,935</b>	<b>15,028</b>	<b>28,414</b>	<b>56,377</b>
<b>Less contributions</b>	<b>(5,114)</b>	<b>(5,114)</b>	<b>(6,819)</b>	<b>(7,761)</b>	<b>(9,017)</b>	<b>(17,048)</b>	<b>(33,826)</b>
<b>Net expenditure</b>	<b>3,410</b>	<b>3,410</b>	<b>4,546</b>	<b>5,174</b>	<b>6,011</b>	<b>11,365</b>	<b>22,551</b>

Broadly, the forecast combines four key components:

1. **Base cost** – this is an extrapolated trend of historical annual average over RY15 to RY19
2. **Major tourism operator’s connection upgrade** – this is the estimated cost of the upgrade, calculated by multiplying project quantities by the unit rates in Aurora Energy’s price book
3. **COVID-19 reduction** – this is a temporary reduction of 25% applied to the base cost for RY22 and RY23 to reflect the potential impact of the COVID-19 pandemic
4. **Contribution reduction** – this is a 60% reduction to the gross connection expenditure forecast to account for assumed capital contributions (which we discuss further in section 6.1).

We consider each component below.

### C.15.3 Relevant policies and planning standards

Aurora Energy’s contributions are currently, governed by its customer contribution policy (dated 21 August 2019). However, it proposes to amend this policy in such a way that consumers will be expected to contribute, at the outset, 60% of connection costs.

This assumption reduces the connections expenditure forecast and drives the capital contribution forecast. We separately consider Aurora Energy’s contributions forecast in section 6.1.

### C.15.4 Information provided

Table C.27 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.27: Information provided

Title	Reference	Date
POD50 - Consumer Connection	E-25	27 February 2020
MOD50 - Consumer Connection Forecast Model	E-26	27 February 2020 (Updated 7 May 2020)
P13 – Other Network Capex – Consumer Connection (presentation slide with Q&A)	V-112	26 March 2020
Capital Contribution Policy	Available on Aurora Energy’s website	21 August 2018
<b>Provided in response to our draft report</b>		
MOD50 - Major Tourism Operator’s Upgrade Customised Estimate <sup>166</sup>	PR-5	22 April 2020
Note regarding MOD50 – Consumer Connection Forecast Model	PR-7	22 April 2020

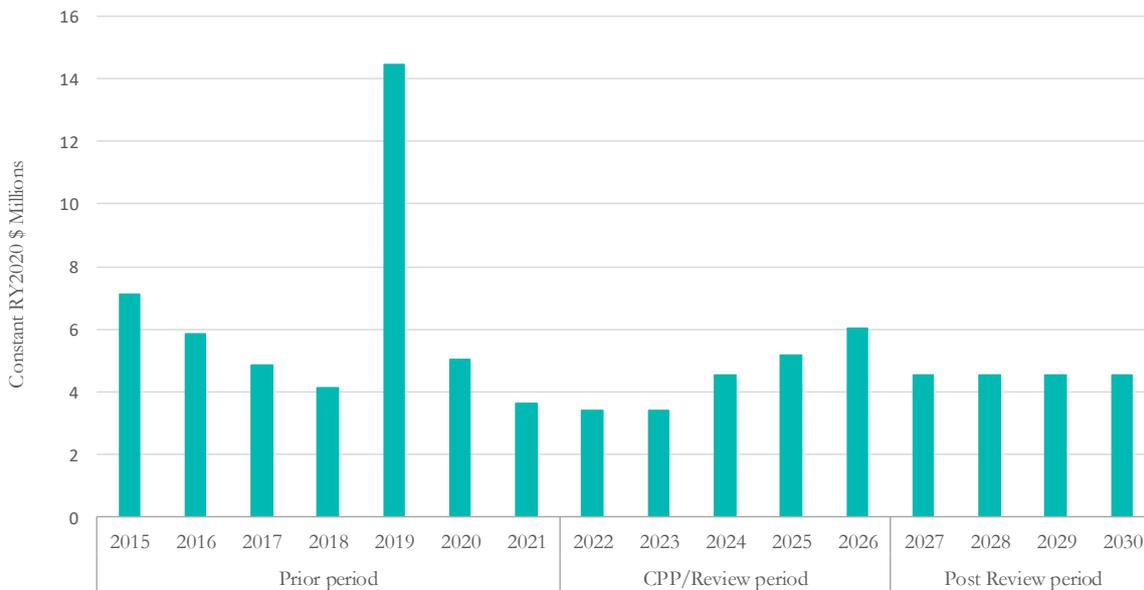
<sup>166</sup> The actual file name provided by Aurora Energy includes the name of the major tourism operator. We have removed this to preserve confidentiality.

## C.15.5 Assessment of forecast method used

### C.15.5.1 Expenditure trends

Figure C.13 shows the historical and forecast expenditure for consumer connections.

Figure C.13: Consumer Connections – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

### C.15.5.2 Expenditure justification

Aurora Energy predicts that gross consumer connections expenditure will not vary, in real terms, relative to that incurred over RY15 to RY19, except for the impact of COVID-19 over RY22 and RY23 and the major tourism operator’s connection upgrade over RY25 and RY26.

Aurora Energy explained that similar abnormal connections were not reflected in the historical data and so are not implicitly included in any forecast based on that data.

### C.15.5.3 Key assumptions used

#### Forecast expenditure consistent with history

Aurora Energy’s assumption that *base* forecast gross connection expenditure (except for the impact of COVID-19 and identified loads) will align with historical expenditure, is not unreasonable. Absent more compelling evidence, assuming no change relative to history is a good starting point.

Economic and other conditions over the RY15 to RY19 period used to calculate the historical average will almost certainly differ from those over the CPP and review periods. However, at the time of writing, it was not clear exactly how these would differ and so what if any adjustment should be made to account for such differences.

The obvious exception is the impact from the COVID-19 pandemic, which is likely to depress connection demand at least for the next few years. Recognising this, Aurora Energy has proposed a 25% reduction to

RY22 and RY23 gross connection expenditure relative to the historical average.<sup>167</sup> In our view, such a reduction is not unreasonable in the circumstances, especially in the absence of other information.<sup>168</sup> Over time, the assumption could be updated once more information is known about the expected impact.

Relying only on history means that there is a slight mismatch between the consumer connections expenditure forecast and other components of the expenditure forecasts. For instance, Aurora Energy has used the network growth forecast adopted by the Commission for the DPP when trending its opex forecasts. Although the forecast differs from that realised historically, the difference does not appear material given the high-level nature of the forecasting approach used and the overlays for COVID-19 and the major tourism operator's connection upgrade.

### **Abnormal expenditure needed for a major tourism operator's connection upgrade**

Aurora Energy estimates that the upgrade will cost of \$5.2 million (or \$2.1 million assuming a 60% contribution), which it calculated by multiplying forecast quantities for its preferred option by unit rates in its price book.

Assuming that there is a need for the upgrade, the cost estimate appears reasonable because:

- the proposed solution appears consistent with the terrain and likely conditions (e.g. snow)
- the estimated quantities (e.g. of lines and equipment) appear consistent with that solution and the physical distances
- the unit costs are sources from Aurora Energy's price-book.

However, although such expenditure is certainly possible, the major tourism operator has not yet committed to needing to expand its connection from RY25. Aurora Energy has only had initial discussions with the operator. The COVID-19 pandemic is likely to dampen demand for tourism activities and the financial performance and position of the operator, at least in the short term.

For similar reasons, Aurora Energy deferred three other tourism-related connection upgrades beyond the CPP and review periods. It is unclear what, if any, effect this unprecedented passage of history will have on the demand for the connections.

In any event, the *need* for the major tourism operator's connection upgrade – as well as the other three upgrades – are contingent on the operators making formal connection requests. Consistently, Aurora Energy recently advised us that it now considers all:<sup>169</sup>

***growth-related projects/programmes have sufficient uncertainty to be considered contingent projects at this time.***

We agree and recommend that the Commission engage further with Aurora Energy on how best to recognise this in the CPP determination.<sup>170</sup>

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<sup>167</sup> Aurora Energy has also forecast a 20% reduction in RY21, which is prior to the CPP and review periods.

<sup>168</sup> To be clear, our view is that the COVID-19 pandemic is likely to lead to some reduction in connection demand compared to what would otherwise be the case. However, because it is unclear to us – and most – exactly how much reduction there will be or for how long it will last, we cannot provide an alternative view at this stage. Given this, we also cannot conclude that Aurora Energy's proposed reductions are unreasonable in the circumstances.

<sup>169</sup> Aurora Energy, Memo from Glenn Coates to Eli Grace-Webb, *Response to follow up questions prompted by Commission feedback*, 12 May 2020, p. 2.

<sup>170</sup> For instance, we understand that the current IM include specific expenditure thresholds before a project would meet the definition of 'contingent project'. We also understand that the IM can be amended for a specific CPP determination. We consider it outside of our verification scope to provide a view on such amendments.

### **Contribution rate of 60%**

As discussed in section 6.1, Aurora Energy's assumed 60% is not unreasonable in the circumstances, although it will need to take some action to realise that outcome.

#### **C.15.5.4 Benchmarking**

Given the nature of this capital expenditure, no direct benchmarking analysis was undertaken. Our view on the capital contribution policy and proposed changes is provided in section 6.1.

#### **C.15.5.5 Contingency factors**

No contingency factors have been included in this expenditure forecast.

#### **C.15.5.6 Interaction with other forecast expenditures**

Aurora Energy has modelled the relationship between the consumer connections and connection-related capital contributions forecasts, using the same model to do so – which is sensible.

In theory, there is also a link between new connections, demand growth and any augmentation capex needed to support that growth. Aurora Energy has not modelled that directly. However, in the circumstances, that is not unreasonable given that historical demand growth has been used to inform future peak demand growth – as discussed further in section 6.2 – and that demand (for relevant zone substations) has been used to inform the proposed major growth projects.

### **C.15.6 Deliverability**

The connection works are undertaken by independent contractors pre-approved or authorised to work on Aurora Energy's network and engaged by the proponents. We do not see any deliverability issue with respect to these capital works.

### **C.15.7 Our finding**

In our view, Aurora Energy's consumer connections expenditure appears consistent with the expenditure objective. Given the need for the major tourism operator's connection upgrade (and other connections) is contingent on formal connection requests being made, that component of the expenditure forecast should be considered as a contingent project.

Our view is based on the following observations:

- relying on historical expenditure to project future expenditure is not an unreasonable approach
- factoring in a 25% reduction in base connections in RY22 and RY23 is not unreasonable in the circumstances and could be further refined during the CPP determination process when more information is known
- a 60% contribution rate is possible if Aurora Energy amends its connections policy as proposed
- the major tourism operator's connection upgrade is contingent on a formal connection request being made – the timing of which may be affected by the COVID-19 pandemic due to its potential adverse impact on revenues for the operator
- appropriate modelling has been undertaken to determine the forecast.

Based on these findings we consider the connection capex of \$11.4 million and \$22.6 million forecast for the CPP and review periods respectively are verified. We also consider that \$2.1 million of the latter figure

over the review period could be considered a contingent project along with other potential tourism related connections previously identified by Aurora Energy that may be affected by the COVID-19 pandemic.

### **C.15.8 Completeness and key issues for the Commission**

The information provided by Aurora Energy on forecast vegetation management was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own review of the information, the Commission may wish to consider:

- what trigger or triggers should be used if the major tourism operator's connection upgrade is treated as a contingent project, noting that demand at a certain level is an obvious candidate
- whether it is realistic that Aurora Energy can realise 60% contributions from consumer connections
- whether the assumed 25% reduction in consumer connection expenditure in RY22 and RY23 due to the COVID-19 pandemic are appropriate, including once more information about the potential impact of the pandemic are known.

## C.16 ICT CAPEX AND OPEX (C11)

Table C.28: Verification summary – ICT capex and opex (\$2020, \$million)

<b>Expenditure category</b>	ICT Capex and Opex	
<b>Aurora Energy CPP forecast</b>	CPP period: \$9.2 million capex, \$10.2 million opex Review period: \$12.2 million capex, \$17.0 million opex	
<b>Recommendation</b>	<b>Verified:</b> CPP period: \$9.2 million capex, \$10.2 million opex Review period: \$12.2 million capex, \$17.0 million opex	<b>Unverified:</b> CPP period: \$0 million capex, \$0 million opex Review period: \$0 million capex, \$0 million opex
<b>Expenditure outcome assessment</b>	Need for the spend appears clear based on existing asset management and business support applications, and serious data integrity issues that are compromising efficient management and operation of Aurora Energy’s network.  The forecasting method appears appropriate, with the bottom-up estimating approach providing the best opportunity for work to fully scheduled ICT initiatives through phased implementations, as well as allowing for prioritising the most critical ICT requirements to improve network assets management  Benchmarking suggests Aurora Energy capex and opex spend is consistent against Australian electricity utilities.	Need for the spend appears clear based on existing asset management and business support applications, and serious data integrity issues that are compromising efficient management and operation of Aurora Energy’s network  The forecasting method appears appropriate, with the bottom-up estimating approach providing the best opportunity for work to fully scheduled ICT initiatives through phased implementations, as well as allowing for prioritising the most critical ICT requirements to improve network assets management  Benchmarking suggests Aurora Energy capex and opex spend is consistent against Australian electricity utilities
<b>What needs to be done</b>	NA	NA
<b>Potential scope for improvement</b>	Identify expected business and customer benefits, including targeted savings, and include these in relevant renewal capex and network maintenance expenditure forecasts	

### C.16.1 Project description

The information and communications technology (ICT) portfolio covers both the capex and opex of supporting and enhancing infrastructure, information services and applications that support Aurora Energy’s system operations and business support. It excludes staff costs that are otherwise captured in the SONS or people cost programs.

The current priorities are:

- improving the way information is managed and used across Aurora Energy, and
- establishing an enterprise asset management system capability.

This work has already commenced – and will be largely completed by the commencement of the CPP period. Given the urgency with which capabilities must be improved, Aurora Energy is not considering an enterprise resource planning (ERP) transformation at this stage, but a transition based on core enterprise systems, and consistent information management.

### C.16.2 Cost estimate / expenditure forecast

Table C.29 shows the forecast expenditure during the CPP and review periods.

Table C.29: Forecast expenditure – ICT capex and opex (\$2020, \$million)

Item	RY22	RY23	RY24	RY25	RY26	CPP 3-year total	Review 5-year total
Capex	5.36	2.09	1.72	1.55	1.50	9.17	12.22
Opex	3.47	3.30	3.48	3.42	3.37	10.25	17.03

### C.16.3 Relevant policies and planning standards

Deloitte conducted a review in August 2019, which reviewed the requirements in the following areas:

- asset management
- corporate
- customer and commercial
- enterprise technology and infrastructure
- operational technology.

Deloitte’s final report outlined the priorities for the implementation and upgrading of applications to improve the Aurora Energy core systems.<sup>171</sup> In response, Aurora Energy has prepared an Information Systems Strategic Plan 2025 (ISSP 2025).

### C.16.4 Information provided

Table C.30 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.30: Information provided

Title	Reference	Date
POD60 Information and Communications Technology   Portfolio Overview Document	E-56	18 March 2020
MOD60 ICT Capex Forecast Model	E-55	18 March 2020
MOD82 ICT Opex Forecast Model	E-54	4 March 2020

<sup>171</sup> Deloitte, Current State Technology Review, August 2019.

Title	Reference	Date
RFI No D455 Information Systems Strategic Plan 2025 (ISSP 2025) ver 9	V-44	17 March 2020
200317 Information and Communications Technology - Capex and Opex presentation	V-67	19 March 2020
RFI No D449 - Aurora Energy - Current State Technology Review - Final	V-76	17 March 2020
RFI No D452 - Core ICT Systems model	V-61	18 March 2020
RFI No D454 - Aurora Energy Asset Management Maturity Assessment	V-160	17 November 2017
RFI No D465 - Budget Details - Master_04 29.01.2020 model	V-49	17 March 2020
RFI No D474 - Business Plan - Technology Dashboard	V-46	17 March 2020
RFI No D474 - Business Plan - PG16-Targets - as at 17 March 2020	V-50	17 March 2020
RFI No D474 - Business Plan - PG30-KPIs - as at 17 March 2020	V-51	17 March 2020
<b>Provided in response to our draft report</b>		
200429 WSP benchmarking analysis	PR-53	4 May 2020
200502 ICT business benefits model	PR-52	4 May 2020
ICT_POD_v_7%20final.doc	PR-54	4 May 2020
ICT Capex Forecast Model - Post IV Review	PR-50	4 May 2020
ICT Opex Forecast Model - Post IV Review	PR-51	4 May 2020
Notes regarding Revised ICT Forecast and Additional Supplementary Info	PR-56	4 May 2020

## C.16.5 Assessment of forecast method used

### C.16.5.1 Expenditure trends

Figure C.14 and Figure C.15 show the historical and forecast expenditure for the ICT capex and opex program.

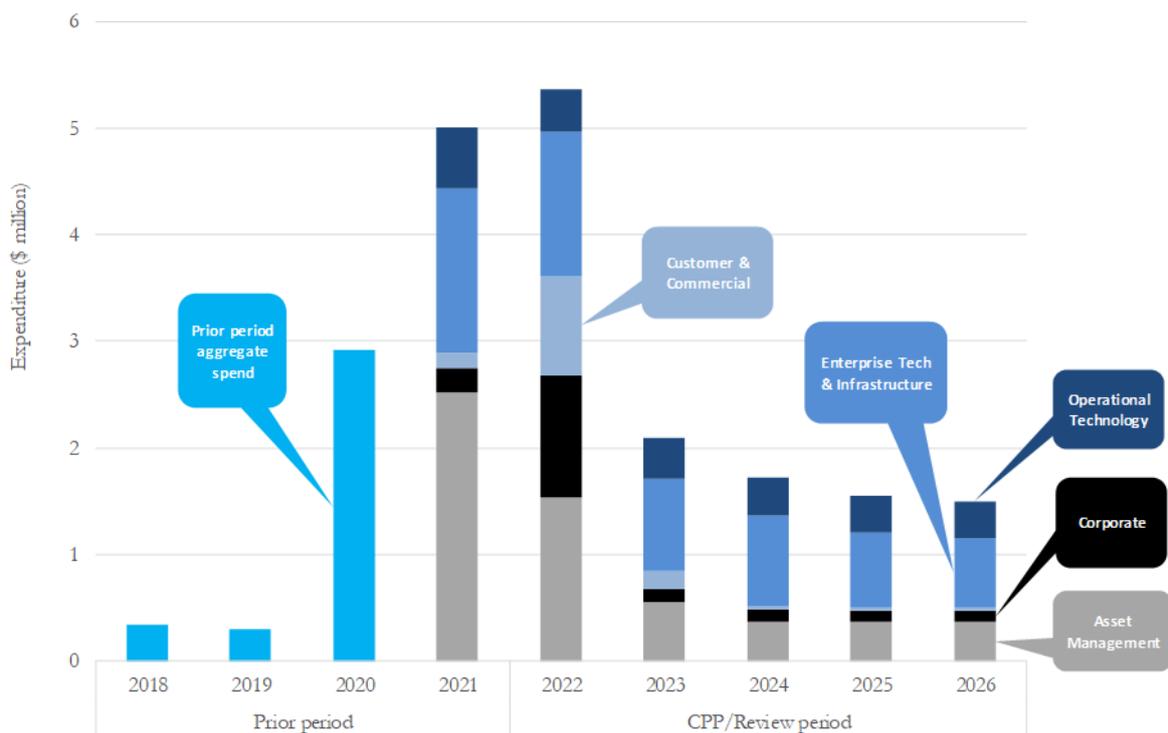
For **ICT capex**, the main expenditure in RY20 relates to the initial phase for the introduction of an asset management system, through the development of a business case investigating several options and nominating a preferred vendor. The focus areas for the CPP and review periods are:

- the implementation of an asset management system
- an upgrade of the existing GIS system
- the delivery of a new financial management system
- new customer billing system.

For **ICT opex**, the increase in RY20 is due to a corporate direction to investigate moving from existing bespoke in-house applications to a cloud-based environment and reducing opex on existing applications to a minimum ahead of the transition. During the CPP and review periods, the key drivers are:

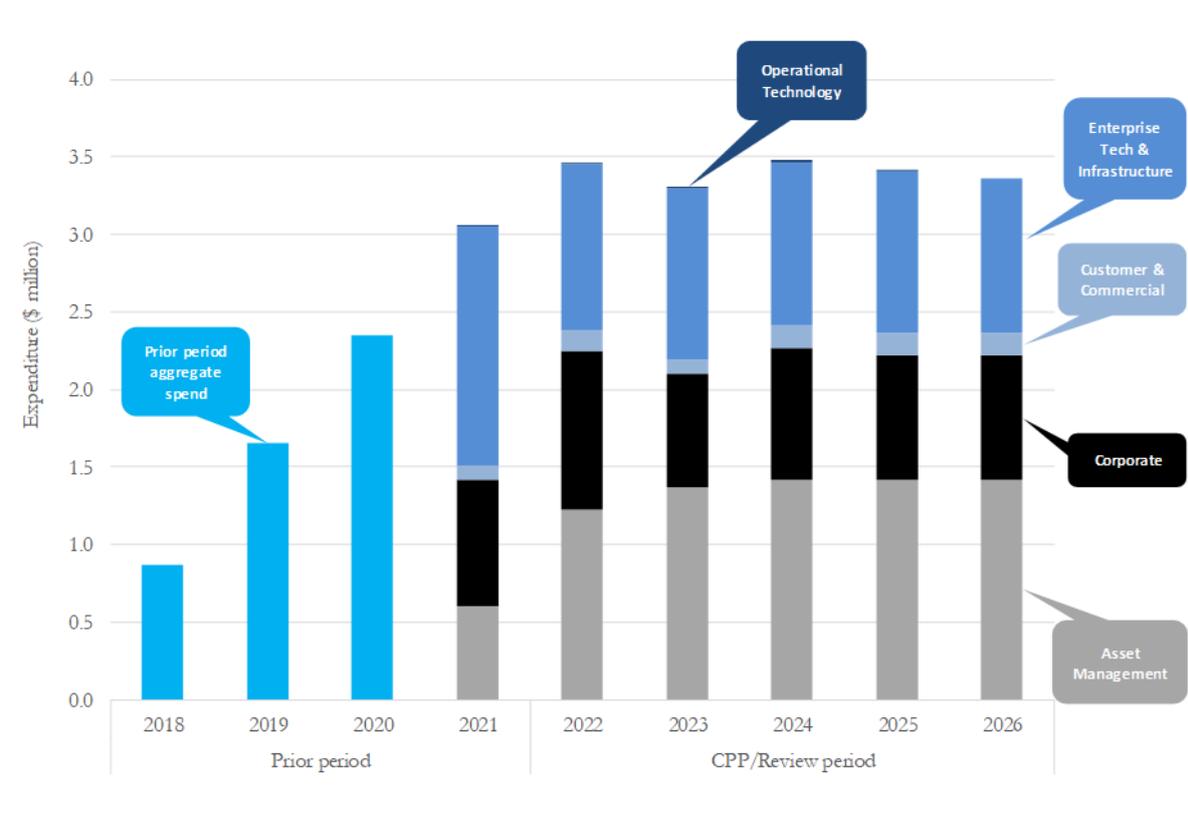
- integration of asset management system and GIS solutions with other corporate systems
- new cyber security measures
- establishing a data warehouse to improve the quality of data used for decision making, and remove duplication of information

Figure C.14: ICT capex – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure C.15: ICT opex – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

### C.16.5.2 Expenditure justification

Prior to separation from Delta in July 2017, Aurora Energy relied upon Delta for ICT systems and related services. Since separation, this environment has been allowed to age and deviate from GEIP, to a point where the risk of service failures is not being fully mitigated.

Aurora Energy engaged an external review of its ICT systems in December 2016 in light of network safety concerns that were being raised publicly at the time. The report noted that:<sup>172</sup>

*routine proactive maintenance was undertaken on the assets until the early 1990s. A run to fail model was then adopted for a number of components of the network since this time.*

Evidently, the ICT systems was one of the components that was run to failure.

A separate independent review in November 2017 assessed the asset management maturity of Aurora Energy using the Commission's asset management maturity assessment tool (AMMAT) – and concluded that the asset management supporting information systems were poor.<sup>173</sup> In particular:

- a lack of a modern database system for the orderly management of maintenance strategies and work transactions, and no reporting of asset health or identification of key operational risks
- there were various sources of data with inconsistencies in the different databases

<sup>172</sup> Deloitte, Review of Aurora Energy Limited/Delta Utility Services Limited - Network Safety Concerns, Dec 2016.

<sup>173</sup> Covaris, Aurora Energy - Asset Management Maturity Assessment, version 1-1, Nov 2017, sections 2.4.2 and 2.4.3, pp. 25-27.

- there was a lack of transparency in the data between Aurora Energy and Delta regarding asset condition and the effectiveness of maintenance.

Covaris acknowledged that Aurora Energy was using an interim solution based on the GIS. In our view, this practice is not consistent with GEIP.

Similarly, a review of the ICT environment in 2019 had the following key findings:<sup>174</sup>

- business applications and information systems were poorly integrated and provided no support to the business
- data and information quality were poor and the lack of integrated technology and information strategies a very limiting constraint
- lack of prioritisation and decision making about key technology projects
- historical preference for in-house solutions and applications, and bespoke data sources which have inhibited daily operations
- requirement for a more strategic approach for business system architecture.

The Covaris review concluded that an integrated plan was needed for staged developments across the business critical application areas – data integrity, an asset management tool, selection of an ERP and SAP separation from Delta by March 2021, upgrade of GIS and PowerFusion distribution management systems, and a works management system.

In response to the findings of these reviews, Aurora Energy developed a business plan outlining the overarching ICT strategy for the business to improve system maturity, through a number of different initiatives in:<sup>175</sup>

- enterprise technology and infrastructure
- data architecture
- customer and commercial
- operational technology
- asset management
- sustainability.

This business plan included tactical plans in these areas, beginning in RY20, through to the delivery and implementation phases during the CPP and review periods. One of the key drivers is for a centralised asset management system with improved data to support ISO55000 certification by RY23.

Consequently, Aurora Energy prioritised CPP capex in the following systems:

- a new asset management system,
- upgrades to SAP, GIS and PowerFusion.

Opex in the CPP and review periods is focused on improving the overall data integrity, and improving integration of the systems to better support more robust business decisions. It also includes costs associated with moving from traditional bespoke applications to cloud-based applications, which will ensure vendor support through using current release software with limited disruption so that operations will continue without interruption.

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<sup>174</sup> Deloitte, Aurora Energy Limited - Current State Technology Review: Findings Report, Aug 2019.

<sup>175</sup> Aurora Energy, RFI No D474 - Business Plan - Technology Dashboard, 17 Mar 2020.

## Forecasting approach

Aurora Energy acknowledges that it is usual practice within industry to consider using a base, step and trend approach to forecasting ICT opex. However, this relies upon having a stable, business-as-usual base year, which Aurora Energy does not have due to the inherent issues with the current environment.

For this reason, Aurora Energy has adopted a bottom-up estimate of the minimum work required to maintain existing ICT services, manage risks to the continuity of service and introduce and implement new systems to address the critical issues identified by the external reviews.

In response to the findings of the 2019 Deloitte review, Aurora Energy developed a strategic plan to set the focus for initiatives over the five-year period to RY25:<sup>176</sup>

- enterprise asset management
- stable, secure, resilient and integrated operational systems
- improved digital collaboration with partners of Aurora Energy
- enablement of ISO55000 certification
- improved staff collaboration and customer experience.

For each of these initiatives, an internal review with asset management, operational and business support staff identified a number of potential system enhancements and/or additions that would address the broader initiative need. Each option was assessed qualitatively against key criteria:

- key drivers
- benefits (qualitative description only)
- scope
- key activities
- forecasting approach
- assumptions, clarifications, exclusions and performance
- cost components
- deliverability (phasing)
- governance.

Based on the information available, Aurora Energy appears to have undertaken detailed analysis when examining each need identified during the internal discussions and assessing the optimal timing required to introduce and implement the new or upgraded applications.<sup>177</sup>

## Forecast expenditure

With this background, the ICT expenditure forecasts were generated using a four-stage process:

1. Current state assessment
2. Internal discussions regarding future requirements
3. Development of a bottom-up plan to address the risks and issues identified

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<sup>176</sup> Aurora Energy, Information Systems Strategic Plan 2025 (ISP 2025).

<sup>177</sup> See, for instance: Aurora Energy, RFI No D465 - Budget details - Master\_04 29.01.2020 model. This model details each of the initiatives across the range of areas identified in ISSP 2025.

4. Internal peer review of the plan by the executive team, together with three challenge rounds by:
  - a. Aurora Energy Board
  - b. the recently appointed general manager of digital transformation
  - c. the CPP Governance Committee

where timing and deliverability were challenged and moderated to reduce expenditure to an optimal total for the CPP and review periods.

In the model provided to us, there were reductions made from the original consultation budget following a moderation process to adjust allowances or reassess the need for the program during the CPP and review periods.

Costs included in the ICT capex and opex forecasts are high-level estimates based on market research that Aurora Energy has done, with internal challenges on the rates used. For instance, an initial estimate for the asset management system of \$6.5 million was revised down to \$3.4 million based on benchmarking of experiences within other entities that have recently introduced asset management frameworks. Wherever feasible, Aurora Energy appears to have sought to minimise costs by making use of existing applications.

The internal peer review and challenge process subsequently reduced the planned ICT expenditures for the six years from RY20 to RY25 from \$51 million to \$38 million.

## Procurement

Procurement of the new ICT systems will be guided by the Aurora Energy procurement standard.<sup>178</sup> This standard defines the principles that Aurora Energy adopts in procuring goods and services, and the five different types of procurement methods used in the course of business.

For ICT expenditure, there are five approaches that may be employed in procuring hardware and software solutions:

- **All-of-Government contract** – Aurora Energy is an eligible agency for ‘All-of-Government’ contracts through the Ministry of Business, Innovation and Employment. This provides for bulk-purchasing through a number of different contracts in relation to ICT:
  - the All-of-Government IT hardware contract
  - the ICT Common Capability Microsoft licencing agreement for subscription-based, perpetual and cloud software licencing
  - the ICT Common Capability telecommunications as a service contract for network, telecommunications and managed security services
  - the All-of-Government office supplies contract for ICT consumables
- **Direct procurement** – for instances where a sole supplier has the skills and the capability to deliver the goods and services required efficiently and on-time
- **Written quotations** – for instances where goods and services are of low value but high risk
- **Tender** – for circumstances where the goods and services are of high value and high risk, and a formal tender process is considered appropriate to test the market
- **Group purchasing** – bulk-purchasing through the parent company.

Table C.31 summarises the procurement approaches to be used for the capex and opex programs.

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<sup>178</sup> Aurora Energy, *AE-SA14-S Procurement Standard*, version 1.0, 5 July 2019.

Table C.31: ICT procurement approaches

Program	Nature of expenditure	Procurement method
Capex	System operations, network and business support	<ul style="list-style-type: none"> <li>• All-of-Government contracts</li> <li>• Direct procurement</li> <li>• Written quotes</li> <li>• Group purchasing</li> </ul>
Opex	ICT hardware, asset management system	<ul style="list-style-type: none"> <li>• All-of-Government contracts</li> <li>• Direct procurement</li> <li>• Tender</li> <li>• Group purchasing</li> </ul>

Aurora Energy has advised that cost control will be achieved through three key initiatives:

- Project managers following a consistent project methodology through a project management support hub
- A governance framework with groups focused on program management and oversight of project costs
- FSAs that should maintain labour and plant costs at efficient levels, and ensure on-time delivery of the programs.

For the ICT programs, deliverability will be managed through dedicated service providers for major ICT projects, and internal staff for the minor upgrades.

Aurora Energy's proposed procurement approaches appear consistent with standard industry practice based on our industry experience. Although we are less familiar with the New Zealand all-of-government contract initiative, it should help achieve benefits through the bulk-purchasing power of the contracts.

### C.16.5.3 Key assumptions used

Aurora Energy reviewed the support for its existing critical business systems and found that its:<sup>179</sup>

- SAP business system was installed in 2005, and is a past version, with database support ending later this year, and operating system support ending in 2022
- current GIS instalment is several versions behind the most recent version, with no security patches now being applied, and support having ended in 2018
- distribution management system is out of date, with support having ended in 2017
- the GIS requires new firewalls to protect against hacking – a key security risk.

### C.16.5.4 Benchmarking

Aurora Energy has had several external reviews done to identify the current state of its ICT capabilities and recommend what to do to bring Aurora Energy up to GEIP with regards to asset management and corporate information systems. These reviews have reviewed the risks inherent in the existing ICT systems and proposed the most efficient approach to addressing the key issues, without specifying applications.

<sup>179</sup> Aurora Energy, RFI No D452 - Core ICT Systems, 17 March 2020.

The estimated costs that Aurora Energy has used in its forecasts are its current best values, based on knowledge of these systems and costs for comparable installations seen elsewhere, including by its external advisor Deloitte.

To assess the efficiency of Aurora Energy's forecasts, we have benchmarked it against data reported to the AER by Australian EDBs.<sup>180</sup> In doing so, we have:

- **Used *total* recurrent ICT expenditure.** In assessing ICT expenditure, the AER benchmarks recurring total expenditure (totex) across all EDBs in the Australian national electricity market; that is, expenditure (capex and opex) that is related to maintaining existing ICT services, functionalities, capability and/or market benefits, and occurs at least once every five years.
- **Used a five-year average.** The AER notes that recurrent ICT expenditure can be 'lumpy', especially given that these expenditures occur on varying cycles (two, three, four and five years). To account for this, a rolling 5-year average to 'smooth' the historical data is used. For the purposes of benchmarking Aurora Energy with the Australian DNSPs, we have used a five-year average for recurring totex reported in the Australian EDB regulatory disclosures to the AER over the period 2015–19, converted to real \$RY20 terms. We have used the average annual recurring totex for the Aurora Energy review period in the benchmarking, converted to real \$RY20 terms, in *Australian* dollars, to allow for direct comparison.
- **Benchmarked expenditure per customer and ICT user.** Currently, the AER compares ICT expenditure per customer and ICT user as it has identified a strong correlation between recurring totex and these factors. We have adopted a similar approach in the benchmarking charts below for Aurora Energy, using the opex forecast as a proxy for the recurrent expenditure, and the total number of FTEs at Aurora Energy as the proxy for the number of IT users.<sup>181</sup>

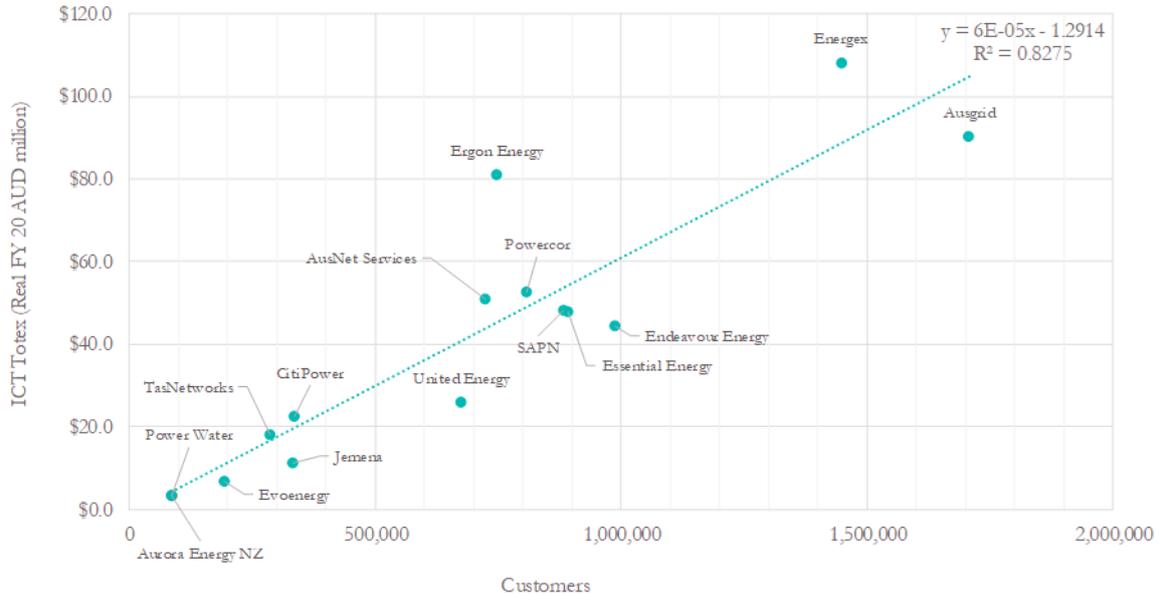
Our benchmarking results are shown in Figure C.16 and Figure C.17 below – which suggests that the planned recurring expenditure for Aurora Energy is comparable to Australian EDB peers.

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<sup>180</sup> See: AER, Non-network ICT capex assessment approach, 28 November 2019. We have used Australian EDB data because equivalent data is not available for New Zealand EDBs.

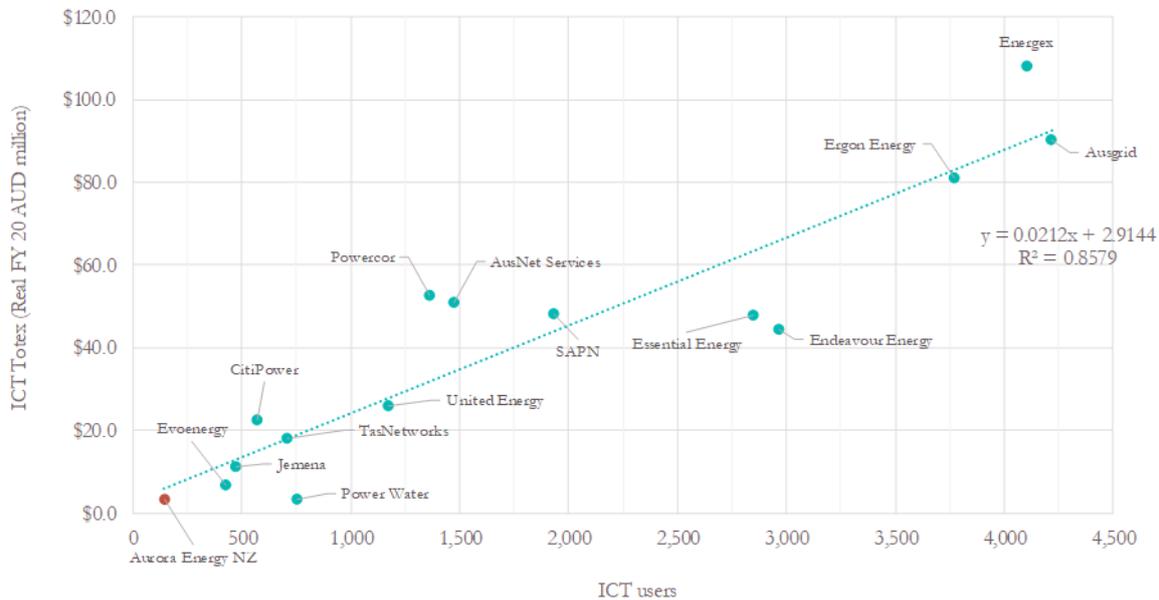
<sup>181</sup> Our analysis did not include the Victorian-based utilities as these entities are currently in consultation with the AER following submission of their next regulatory proposals, and their final ICT budgets have not been determined.

Figure C.16: ICT recurrent expenditure vs customer numbers (\$2020, AU\$million)



Source: AER RIN and Aurora Energy data. Farrierswier and GHD analysis.

Figure C.17: ICT recurrent expenditure vs ICT users (\$2020, AU\$million)



Source: AER RIN and Aurora Energy data. Farrierswier and GHD analysis.

As a comparison, Aurora Energy sought an alternative view on benchmarking with Australian utilities, which incorporated projected forecasts using the draft regulatory submissions of Victorian-based utilities to the AER, and an amended number of ICT users for Aurora Energy.<sup>182</sup> The findings of this review are consistent with our benchmarking, concluding that the revised ICT projections from Aurora Energy

<sup>182</sup> WSP, ICT benchmarking review, 28 April 2020. Aurora Energy subsequently advised that we should assume 160 ICT users for the CPP and review periods covering permanent employees and contractors.

compare favourably with the historical average expenditure benchmarks for electricity distribution utilities in Australia.

#### C.16.5.5 Contingency factors

We understand that no contingency factors have been included in this expenditure forecast.

#### C.16.5.6 Interaction with other forecast expenditures

ICT capex and opex will have benefits in work scheduling, cost control and delivery performance monitoring that will interact with all of the capex and opex programs, with the intention of identifying and achieving cost efficiencies and improved effectiveness of delivery.

##### **Benefits**

Based on AER definitions for recurrent and non-recurrent expenditure,<sup>183</sup> Aurora Energy reviewed the anticipated benefits towards capex and opex from the proposed system and other ICT improvements.

Recurrent expenditure is defined as that related to maintaining existing ICT services, functionalities, capability and/or market benefits, and is incurred at least once every five years. Non-recurrent expenditure includes upgrades or replacements of systems on a longer cycle than five years, or acquisition of new or expended ICT functionality or capability.

Aurora Energy considers that its proposed ICT expenditure will contribute significantly to it achieving improved works coordination and better decision making. In its modelling, Aurora Energy has assumed that ICT enhancements will constitute 50% of the benefits, with the balance being achieved through people and process changes.

From RY21, Aurora Energy projects the following NPVs (in constant RY20 dollars) based on its cost-benefit analysis:

- 5 Year NPV: (\$4.4 million)
- 10 Year NPV: \$8.2 million
- 15 Year NPV: \$9.6 million.

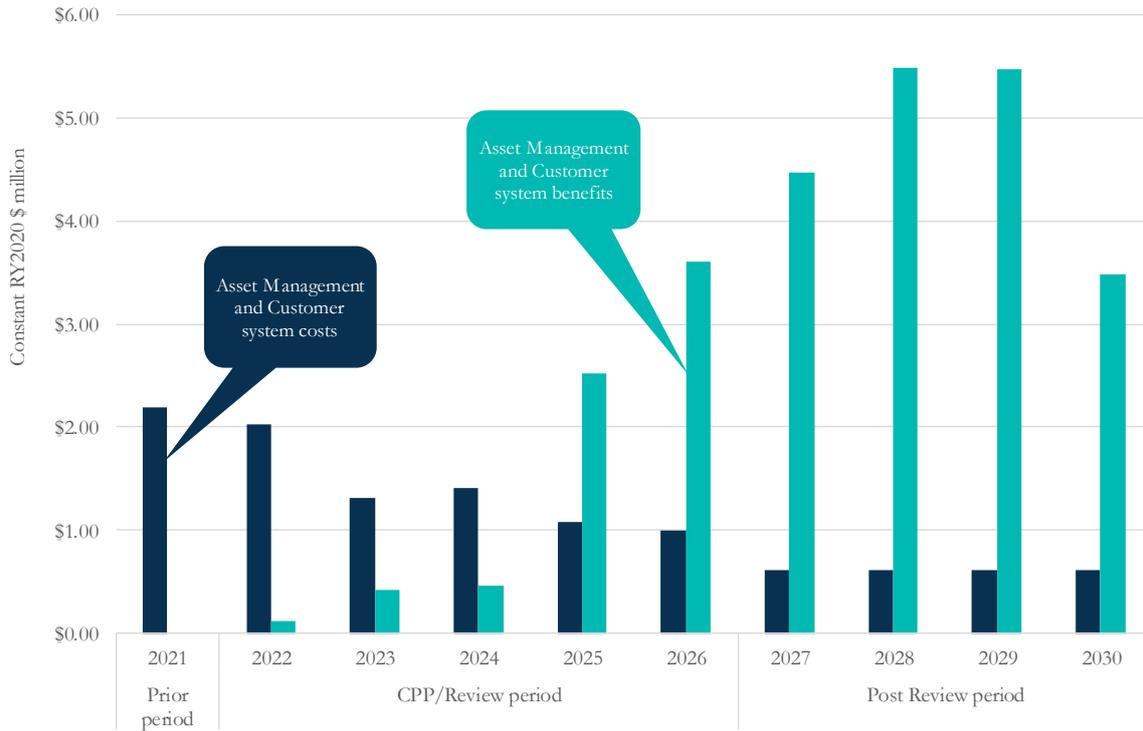
Figure C.18 shows the costs and benefits identified by Aurora Energy for non-recurrent expenditure particular to asset management and customer systems. Looking at the benefits more closely, Figure C.19 shows that there will be some benefits achieved in customer-related system costs, and in avoided costs for asset management resources (through avoiding recruiting additional staff) over the CPP period, with improved data and asset management systems providing for most of the benefits through deferral of asset renewal capex from RY25.

There are also modest savings forecast for preventive maintenance and vegetation management opex from RY25. For preventive maintenance, there is an initial 1% benefit forecast for RY24, increasing to 5% per year for RY26 and later for maintenance deferral through better informed decision making and work/inspection coordination. Vegetation management is projected to benefit by 0.5% per year from RY22 to 2.5% for RY26 and subsequent years.

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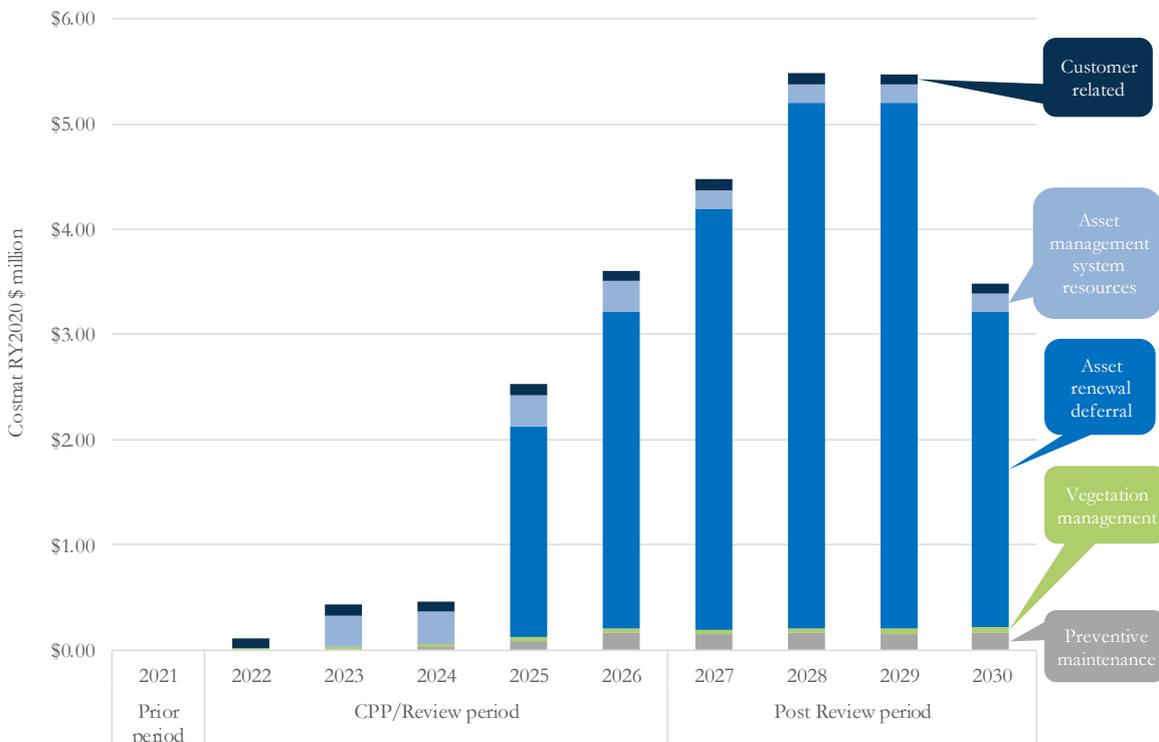
<sup>183</sup> AER, *Non-network ICT capex assessment approach*, 28 November 2019.

Figure C.18: ICT non-recurrent capex – cost/benefit analysis (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure C.19: ICT non-recurrent capex – benefit breakdown (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Aurora Energy has identified and quantified tangible benefits for non-recurring expenditure from the proposed ICT initiatives for asset management and customer systems.<sup>184</sup> This analysis has focused on those programs that are related to the following areas:

- **Asset management** – asset management system and asset performance management
- **Information architecture** – data integrity and warehouse
- **Integration** – technology to support the external service providers
- **Smart Grid** – SCADA
- **Customer systems** – billing and customer relations.

This cost-benefit analysis shows a negative NPV in the first five years from RY21, but a compensating large positive NPV once the next five years are included. This is based largely on an assessment of deferred capex for asset renewal from RY25 and later that has not been justified or supported, but appears to be a best engineering judgement.

The current cost-benefit analysis assumes only minor efficiency improvements in preventive maintenance, in contrast to our industry experience where the development or enhancement of asset management systems coupled with improved asset condition data from an enhanced inspection program would offer greater benefits than 1–5% annually.

In our view, Aurora Energy's cost benefit analysis for its proposed non-recurring expenditure is a reasonable first pass on assessing potential benefits and demonstrating the cost-effectiveness of its proposed strategy over the medium to long term. However, this analysis is not conclusive. Benefits realised in practice from the proposed initiatives should be documented during the CPP period to support any subsequent ICT expenditure proposals.

Limited support for the estimated benefits has made it hard for us to review them. Although we realise it can be hard to credibly estimate such benefits, Aurora Energy could help address this limitation by:

- detailing why the new asset management systems are anticipated to achieve only very minor efficiency improvements in preventive maintenance activities during the CPP period
- providing support for the nominal sums that have been assumed for deferred asset renewal expenditure, particularly as these nominal allowances represent approximately 90% of the anticipated annual benefits from RY25.

It was also unclear to us exactly how the benefits included in the cost benefit analysis relate to the top-down efficiency improvements that Aurora Energy applied to selected asset renewal and network maintenance programs. The basis for those adjustments was not immediately apparent, although there does appear to be some link between these adjustments and the benefits included in cost benefits analysis.

To overcome this limitation, Aurora Energy should confirm whether all of the proposed benefits from the ICT expenditure have been included in the capex and opex forecasts, through the top-down efficiency improvements. Given that recurrent expenditure can also lead to efficiency improvements,<sup>185</sup> it may be

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<sup>184</sup> Originally, Aurora Energy advised that operational and administrative benefits are expected from the proposed ICT initiatives, without being able to provide any quantitative target. The primary driver for the CPP and review periods is addressing clear deficiencies in the ICT services that Aurora Energy has and the constraints and risks these pose to business-as-usual operations. Aurora Energy also provided a qualitative assessment of the anticipated benefits for each initiative.

See: Aurora Energy, RFI No D465 - Budget details - Master\_04 29.01.2020 model.

<sup>185</sup> For instance, replacing an old system with a new system can fix technical issues, provide more functionality, and generally improve productivity.

that the *total* ICT related improvements are greater than the benefits used in the cost benefit analysis for the non-recurrent ICT expenditure.

Finally, the total amount of ICT non-recurring totex included in the cost benefit analysis made up just 36% of the total forecast,<sup>186</sup> excluding any expenditure associated with the GIS system, finance and human resources systems and applications. Although low, this is not unreasonable given that:

- ICT opex will largely by nature, especially where software-as-a-service solutions are being adopted
- some non-recurrent expenditure is required to address currently obsolete and unsupported applications that need replacement so Aurora Energy to function in line with GEIP.

Nevertheless, Aurora Energy should be clearer on:

- how its ICT expenditure is classified as either recurrent or non-recurrent – as this will make it easier for the Commission and stakeholders to better understand the rationale for each proposed initiative
- what, if any, non-recurring expenditure is excluded from the cost benefit analysis – for, even though it may meet the AER’s definition of non-recurrent expenditure, it is still prudent to consider costs and benefits before making investment decisions.

### C.16.6 Deliverability

External consultants on an as-required basis, mostly senior project managers and change managers will support implementation of the major ICT projects. Aurora Energy is confident that there are sufficient resources available in the local market and understands that there is a large resource pool in Christchurch.

Internal staff will carry out minor change projects such as upgrades and enhancements.

All of the ICT programs will be closely monitored against project milestones and deliverables. Aurora Energy staff have been trained in project management techniques to support the supervision of the delivery of the CPP expenditure.

### C.16.7 Our finding

In our view, Aurora Energy’s forecast ICT capex and opex expenditure for the CPP and review periods does not appear unreasonable based on the information that we have reviewed.

Our view is based on the following observations:

- there is an apparent need to address inherent risks associated with:
  - Aurora Energy’s existing asset management and business support applications – and the complex interactions between them,
  - the serious data integrity issues that are compromising efficient management and operation of its network
- moving from in-house software solutions to cloud-based solutions – as Aurora Energy is proposing – is consistent with GEIP and increasingly becoming a necessity in today’s ICT solutions marketplace to ensure that support is provided indefinitely and 24/7
- the proposed ICT initiatives and cost estimates are based on:
  - findings from external reviews that have identified key issues and recommended solutions that appear consistent with GEIP, including by clearly articulating and focusing on business needs

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<sup>186</sup> This includes 51% of the forecast ICT capex and 25% of the forecast ICT opex.

- feedback from consumers and the CAP on the need to improve the timeliness and proactivity of communication with customers around works that affect them
- the forecasting method appears appropriate, with the bottom-up estimating approach providing the best opportunity to schedule the proposed ICT initiatives during the CPP and review period, as well as allowing for prioritising the most critical ICT requirements to improve network assets management
- the four-stage approach used to generate and moderating the forecasts appears robust and rigorous – and, in our view, ensures that the business and consumer needs are fairly captured and analysed against the current needs as detailed by ISSP 2025 and prioritised appropriately.<sup>187</sup>

Based on these findings – and the robustness of the approach Aurora Energy has adopted for ICT expenditure – we consider the ICT capex of \$9.2 million and \$12.2 million forecast for the CPP and review periods respectively are verified. Similarly, we consider that the ICT *opex* of \$10.3 million and \$17.0 million for the two periods respectively is verified.

Our finding is subject to the following limitations:

- although Aurora Energy’s cost benefit analysis is a valid first pass, our experience suggests that actual benefits could be higher and could be realised sooner than that forecast – the reverse could also be true
- lack of support for estimated benefits meant that we could not confirm whether they were appropriate or not
- the direct relationship between the estimated benefits from the ICT expenditure and the top-down efficiency improvements applied by Aurora Energy to select renewal and maintenance programs was not immediately clear to us – and so there could be a mismatch (e.g. overstated estimates in the cost benefit analysis or understated efficiency improvements in the forecasts).

### C.16.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on ICT expenditure forecasts was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether Aurora Energy’s estimated benefits from the proposed expenditure are appropriate as to timing and magnitude
- whether these benefits have been appropriately reflected elsewhere across the capex and opex forecasts.

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<sup>187</sup> Aurora Energy’s preliminary budget appears to have been subject to close internal scrutiny and moderated by its board and executive to ensure that the forecasts are prudent and represent best assessment of efficient costs.

## C.17 PREVENTIVE MAINTENANCE (O1)

Table C.32: Verification summary – Preventive maintenance (\$2020, million)

<b>Expenditure category</b>	Preventive maintenance	
<b>Aurora Energy CPP forecast</b>	CPP period: \$19.0 million Review period: \$30.5 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$19.0 million Review period: \$30.5 million	<b>Unverified</b> CPP period: \$0 million Review period: \$0 million
<b>Expenditure outcome assessment</b>	<p>It is appropriate to use actual RY19 opex to inform efficient base opex, but should not presume it is efficient.</p> <p>Most step changes driven by justified enhancement of inspection activities and align with GEIP and to allow Aurora Energy to collect asset condition data needed to support its asset management planning and asset strategies.</p> <p>Scale growth is not unreasonable.</p>	<p>Although we have verified the base preventive maintenance forecast, we believe there remains scope for potential reductions due to:</p> <ul style="list-style-type: none"> <li>• the benchmarking being inconclusive with regards efficiency of base expenditure</li> <li>• efficiency improvements proposed by Aurora Energy being modest</li> <li>• cost reduction benefits from the new contractor arrangements likely being realisable sooner than that reflected in the top-down efficiency improvements adopted by Aurora Energy.</li> </ul>
<b>What needs to be done for our final verification report</b>	<p>Work with Aurora Energy to understand the efficiency of RY19 expenditure, including how they align with GEIP.</p> <p>Review of RY20 actual costs to assess the impact of the new FSA on preventive maintenance costs.</p>	
<b>Potential scope for improvement</b>	Better understand how preventative maintenance costs will evolve once asset management systems are improved.	

### C.17.1 Project description

Preventive maintenance relates to scheduled work needed to ensure the continued safety and integrity of assets, together with inspections, condition assessment, servicing and testing. The program includes gathering asset nameplate data and condition information for later analysis and planning of work; and is a key source of information feedback for asset management activities.

Aurora Energy acknowledged that in the past, some asset types were neglected, either as maintenance that was not planned, or planned maintenance that was not completed. The program for the CPP and review periods will include enhanced inspections to gather good asset data, both nameplate and condition to inform future asset management activities.

This is a new maintenance category for Aurora Energy adopted for the CPP and review periods, with preventive maintenance typically combined with corrective maintenance for regulatory purposes as routine and corrective maintenance and inspection (RCI).

### C.17.2 Cost estimate / expenditure forecast

Table C.33 shows the forecast expenditure during the CPP and review periods.

**Table C.33: Forecast expenditure – Preventive maintenance (\$2020, million)**

Item	RY22	RY23	RY24	RY25	RY26	CPP 3-year total	Review 5-year total
Expenditure	6.50	6.00	6.46	5.60	5.97	18.96	30.53

### C.17.3 Relevant policies and planning standards

Aurora Energy continues to evolve its policies and planning standards as part of its asset management journey. Key documents that we have seen that are currently influencing preventative maintenance expenditure include:

- asset management policy
- asset management plan
- vegetation management strategy
- maintenance standards
- maintenance checklists and testing forms (numerous – used to guide maintenance activities).

Aurora Energy does not yet have asset management strategy or framework documents, or maintenance strategy documents that we have seen. We understand that it intends to develop these as part of its asset management journey.

### C.17.4 Information provided

Table C.34 presents the information that has been provided by Aurora Energy in relation to the identified program.

**Table C.34: Information provided**

Title	Reference	Date
POD70 Preventive Maintenance	E-32	28 February 2020
MOD70 Preventive Maintenance Forecast Model	E-31	28 February 2020
Network Maintenance (Opex) presentation	V-140	31 March 2020
D032 - Preventive Maintenance Step Changes	V-124	27 March 2020
RFI Nos D028 D060 and D098 - Maintenance opex - benchmarking	V-126	28 March 2020

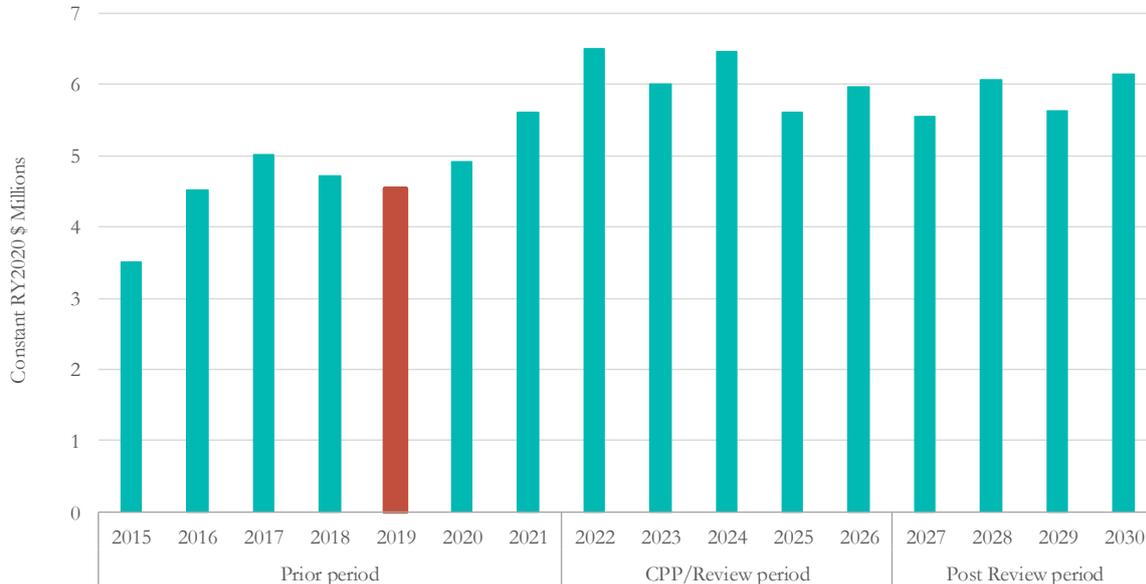
Title	Reference	Date
<b>Provided in response to our draft report</b>		
Maintenance Benchmarking Memo for IV - 29 April	PR-40	30 April 2020
PM Step Changes - Post IV Review	PR-39	30 April 2020
Preventive Maintenance Forecast Model - Post IV Review	PR-41	30 April 2020
200503 Aurora network opex benchmarking	PR-48	14 May 2020

## C.17.5 Assessment of forecast method used

### C.17.5.1 Expenditure trends

Figure C.20 shows the historical and forecast expenditure for the preventive maintenance program. Historical costs increased from RY15 to RY17 before reducing to \$4.5 million in RY19. Aurora Energy proposes an average annual increase of \$1.9 million and \$1.7 million over the CPP and review periods respectively from historical costs, an increase of 42% for CPP and 37% for Review periods on RY19. Expenditure is forecast to remain fairly flat over and following the CPP and review periods apart from the biannual volatility of inspection cycles (as shown in the figure).

Figure C.20: Preventive Maintenance – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Aurora Energy forecasts its expenditure over the CPP and review periods using the base, step and trend method. Aurora Energy applied this method using RY19 as its base year, making a minor adjustment, and adding step changes. It also applies scale escalation.

To address potential efficiency improvements that may be achieved through other initiatives – such as the introduction of an asset management system and other ICT initiatives, establishing new FSAs with three contractors and asset renewal capex that replaces end-of-life and poor performing assets – Aurora Energy

applied top-down efficiency improvements over the CPP and review periods. Forecast improvement for years after the review period were also shown.

The increase in expenditure is driven primarily by an increasing volume of activities, and by undertaking new inspection activities. Forecast increases in network scale have a minor impact on the increase.

### C.17.5.2 Expenditure justification

Aurora Energy has used actual RY19 expenditure as base opex as it considers that these costs reflect business-as-usual recurrent preventive maintenance costs and were the most recently audited data available. Aurora Energy acknowledged that historical data is poor, with no formal record keeping, and any records that were kept are all paper-based or scanned data.

For the CPP and review periods, Aurora Energy has also proposed several step changes to address historical shortfalls in maintenance of some asset types, together with enhancing the inspection program to improve the overall data integrity and asset condition assessments.

With reference to Appendix F, this is consistent with WSP's findings, where it noted examples of insufficient preventative maintenance in the past, including:<sup>188</sup>

- **Zone substation circuit breakers** – where the inspection, testing and maintenance of these assets appeared incomplete<sup>189</sup>
- **Zone substation transformers** – where transformer tap changers were showing signs of deterioration and some are behind their maintenance schedule
- **Support structures** – where, although the pole inspection program had recently been improved, it had not identified all poles that were in poor condition as it has not yet covered the whole network and crossarms were not being inspected adequately and many were found to be in poor condition
- **Distribution switchgear** – where maintenance had not been undertaken consistently and there was no regular inspection program in place.<sup>190</sup>

To address these concerns raised by WSP, Aurora Energy has proposed an enhanced preventive maintenance program for the CPP and review periods, which led it to propose step changes for the following specific activities:

- pole top/crossarm inspections
- LIDAR survey to provide quality data for vegetation management
- restart of ABS maintenance
- support consumer owned pole strategy
- inspections of distribution conductor condition, fittings and joints
- helicopter inspections of subtransmission lines
- LV enclosure inspections
- surge arrester inspections – to mitigate the risks posed by uncontained explosion hazard in public areas
- other inspections and electromechanical relay maintenance.

The top six step changes represent 86 per cent of the total step change increases for the CPP and review periods. The forecast changes for these step changes have been calculated on a volumetric basis.

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<sup>188</sup> WSP, *Design for a better future: Aurora Energy - Independent Review of electricity networks*, Final report, 21 Nov 2018

<sup>189</sup> *Ibid.*, Executive Summary, p. xi.

<sup>190</sup> *Ibid.*, section 9.2.3, p. 78.

These six step changes are considered in the following tables. Although we have not reviewed the other step changes in detail, we have not identified any concerns with them at this stage.

Table C.35: Pole top / crossarm inspections step change

Component	Description
Name	Pole top / crossarm inspections
Value	CPP period: \$1.4 million Review period: \$2.3 million
Description	Aurora Energy has calculated the work volumes based on the total number of poles and an inspection cycle of five years. For this initiative, an additional \$50 per pole top for inspection using camera mounted on a stick was assumed.
Driver	A key driver for this initiative is a WSP finding – the current inspection regime depends on ground-based inspection alone, which WSP identified as insufficient to adequately assess the crossarm and pole top condition. Aurora Energy has proposed to use stick mounted camera to inspect all poles during five-year inspection cycle.
Volumes	The program is based on a five-year inspection cycle for LV and distribution pole tops, which is consistent GEIP for overhead line inspection. All subtransmission pole tops will be covered by helicopter inspections, and so are not included in the volumes – which we consider is appropriate.
Unit rate	The proposed unit rate is comparable with costs for similar work undertaken by Australian EDBs.
Finding	<b>Verified</b> – the initiative is consistent with GEIP and will improve the quality and completeness of data for poles from the inspection program. It is not unreasonable to include this activity in the work undertaken when inspecting poles. The projected quantities for the CPP and review periods do not appear unreasonable.

Table C.36: LIDAR survey step change

Component	Description
Name	LIDAR survey
Value	CPP period: \$1.0 million Review period: \$1.5 million
Description	LIDAR surveys identify clearance violations, vegetation encroachment and natural terrain details. The vegetation management program for the review period includes consideration of LIDAR data to improve understanding of vegetation cutting needs, and to help drive overall cost efficiencies.  If undertaken, it would support Aurora Energy’s vegetation management standard.

Component	Description
Driver	Aurora Energy has historically relied upon ground inspections of vegetation and line clearances, which does not provide for accurate and robust data, or support any potential cost savings.
Volumes	Forecast work quantities are based on covering half of the aggregate network length (urban and rural) each year, starting in RY22, to support the vegetation catch-up stage.
Unit rate	The unit rate per kilometre included in the review period forecast was provided by a third-party supplier. This appears reasonable as it reflects market value for this work.
Finding	<b>Verified</b> – The forecast LIDAR surveys are reasonable. LIDAR surveys are consistent with good industry practice and will support vegetation management and are used by many EDBs across in New Zealand and Australia to identify line clearance issues and improve vegetation management practices. Undertaking the initiative over the CPP and review periods will allow Aurora Energy to do network resilience studies for weather and test the current design standards across its network. Deferring the start of these surveys will reduce vegetation effectiveness and reduce understanding of network conditions.

Table C.37: Air break switch step change

Component	Description
Name	Air break switch maintenance
Value	CPP period: \$0.9 million Review period: \$1.4 million
Description	Aurora Energy assessed three different options for this initiative and nominated a solution that requires an inspection of the air break switches, with longer-term full routine maintenance.  The switchgear will be maintained – or replaced if appropriate – based on condition and prioritised by criticality based on load served. The catch-up inspection cycle is set as two years, with the air break switches to be maintained on a four-yearly cycle.
Driver	WSP identified that maintenance of this distribution switchgear was planned but never completed, resulting in air break switches being in poor condition. Some are categorised as ‘Do Not Operate’ units, which represent a reliability issue.
Volumes	The proposed work volumes are not unreasonable, with the focus on addressing the switches that pose the greatest risk to network security, and allowing Aurora Energy to better understand the maintenance requirements and address the WSP comment.  Aurora Energy reduced the volumes to cover only 60% of the asset fleet following internal moderation, especially given the initiative is reliability driven rather than safety driven.

Component	Description
Unit rate	Aurora Energy has proposed a unit rate for maintenance work of \$2,000 per air break switch. The proposed unit rate is comparable with costs based on our commercial and industrial experience in the Australian electricity market. The unit rate proposed by Aurora Energy is reasonable when benchmarked against another distribution utility.
Finding	<b>Verified</b> – there is an obvious need to improve maintenance of this asset fleet and the unit rate and volumes are not unreasonable.

Table C.38: Consumer owned poles step change

Component	Description
Name	Consumer owned poles
Value	CPP period: \$0.9 million Review period: \$1.1 million
Description	Aurora Energy has forecast inspecting all of the 4,000 consumer owned poles that it estimates were installed prior to 1984 by RY27 before handing ownership of them over to consumers as part of its Consumer Owned Poles Strategy.
Driver	<p>As required by electricity regulations, before Aurora Energy can handover pre-1984 consumer owned poles it must ensure that they are in good condition – which requires both preventative and corrective maintenance. Historically, Aurora Energy did not specifically address the maintenance requirements for these poles, and attended any pole failures.</p> <p>There have been four unassisted failures in the consumer-owned population since July 2019 in a fleet of 4,000 poles. With reference to Appendix D.3, this is a higher failure rate than:</p> <ul style="list-style-type: none"> <li>the current unassisted pole failure rate for the broader Aurora Energy pole population of approximately four poles per 10,000 pa</li> <li>that for comparable Australian EDBs, which target less than 1 per 10,000 poles per year.</li> </ul> <p>To address this heightened safety risk three options were considered:</p> <ul style="list-style-type: none"> <li>do nothing – which was considered not to be in the best interest of consumers or the community due to public safety</li> <li>Aurora Energy approved test of consumer poles</li> <li>an unapproved third-party test of consumer poles.</li> </ul> <p>Consistent with the asset management approach for the Aurora Energy owned poles, the preferred option is to undertake Deuar tests on all consumer-owned wood poles and visual inspection of concrete poles.</p>

Component	Description
Volumes	<p>Aurora Energy assumes a three-year program to inspect all consumer owned poles, commencing RY21 and ending RY24. Initially, 400 poles are identified for RY21 with the remaining 3,600 poles spread evenly across CPP period to RY24.</p> <p>This volume profile appears consistent with the proposed timing for the step change, except for the 100 poles identified for RY25 and RY26, which Aurora Energy advised was included in error.</p>
Unit rate	<p>For inspection of the consumer poles, Aurora Energy has nominated a unit rate of \$250 per pole based on historical costs and allowance for additional customer liaison and access vegetation clearance. The proposed unit rate is comparable with costs based on our commercial and industrial experience in the Australian electricity market.</p>
Finding	<p><b>Verified</b> – the volume of work and unit rates do not appear unreasonable, and the approach is consistent with the asset strategy in place for the Aurora Energy owned poles (refer section D.3). The need to address the safety risk posed by the poles also appears apparent from the data provided to us.</p> <p>The Commission may want to consider this step change further, including as to whether it is appropriate for the costs to be included within the regulated cost base.</p>

Table C.39: Distribution conductor inspection step change

Component	Description
Name	Distribution conductor inspection
Value	<p>CPP period: \$0.5 million</p> <p>Review period: \$0.8 million</p>
Description	<p>Aurora Energy is proposing to introduce a distribution conductor inspection cycle to help address safety and reliability risks affecting that fleet.</p>
Driver	<p>The base year 2019 does not include any provisions for distribution conductor survey work. In its review of the Aurora Energy network, WSP found:<sup>191</sup></p> <p><i>there are 10 to 25 public safety incidents per year related to distribution overhead line conductors ... a common mode of failure for this asset class is failure of the conductor by way of corrosion or fatigue, both of which are related to age. Aurora [sic] does not have a dedicated inspection and testing program for overhead conductors but undertakes visual inspection on an opportunistic basis when inspecting other assets.</i></p> <p>WSP concluded:<sup>192</sup></p> <p><i>that distribution overhead lines pose a moderate risk to network reliability and safety, mostly due to their relatively high failure rate but low consequences to public safety when they fail.</i></p>

<sup>191</sup> WSP, Design for a better future: Aurora Energy - Independent Review of electricity networks, Final report, 21 Nov 2018, section 12.7, p. 116.

<sup>192</sup> *Ibid.*

Component	Description
Volumes	The program is based on a five-year inspection cycle, which is consistent GEIP for overhead line inspection.
Unit rate	<p>The unit rate for ground inspection work is considered reasonable, and Aurora Energy calculated the lengths of lines to be inspected by helicopter and ground-based on current estimates of line length and inaccessible length that required helicopter inspection.</p> <p>Aurora Energy has used a combination of unit costs – \$1,000 per km for helicopter inspection based on recent costs for similar activity and \$50 per km for ground inspection. These estimated rates are based on historical third-party costs. They do not appear unreasonable.</p> <p>The proposed unit cost for ground-based inspections is comparable with costs for similar work in the Australian electricity market.</p>
Finding	<b>Verified</b> – although the risk assessed by WSP may not necessarily be considered ‘intolerable’ as defined by Aurora Energy, the absence of any inspection program for overhead lines is not consistent with GEIP. The proposed inspection expenditure – based on proposed unit costs and volumes – is not unreasonable.

Table C.40: LV enclosure inspection step change

Component	Description
Name	LV enclosure inspections
Value	CPP period: \$0.3 million Review period: \$0.8 million
Description	Aurora Energy is proposing to introduce a distribution conductor inspection cycle to help address safety risks affecting that fleet.
Driver	Aurora Energy has historically had poor records on the age and condition of its LV enclosure fleet. At the same time, it has had several safety concerns raised about those assets, both to its staff and contractors, and the wider public.
Volumes	The assessment of the work volumes is based on rigorous review of the asset fleet population.
Unit rate	Aurora Energy has proposed a unit rate \$59 per enclosure for inspection. This is comparable with similar inspection costs for some Australian distribution utilities.
Finding	<b>Verified</b> – the forecast expenditure does not appear unreasonable and the initiative addresses one of WSP findings. It also supports the LV enclosures renewals program where these assets are classified, by Aurora Energy, as a high safety risk.

### C.17.5.3 Key assumptions used

#### Base opex

Aurora Energy has assumed that actual RY19 expenditure for preventative, corrective and reactive maintenance provides an appropriate base cost for forecasting expenditure over the CPP and review periods. It describes this expenditure as efficient.

We were unable to confirm whether that expenditure, in aggregate across the three maintenance programs, was efficient or not. Although benchmarking Aurora Energy's RY19 expenditure was inclusive on whether it is consistent or not with other EDBs in a statistical sense, other factors indicate that that expenditure *may* include some inefficiency, or at least that there is some room for improvement.

For instance:

1. Delta was the sole provider of maintenance services to Aurora Energy in RY19 and the contract in place at that time – and the rates charged under it – were not market tested<sup>193</sup>
2. Delta is a related party so we cannot presume that the rates charged to Aurora Energy reflect the outcomes of arms' length negotiations<sup>194</sup>
3. Aurora Energy was not undertaking many of the maintenance activities in RY19 that it now proposes to do and that other EDBs were doing at the time<sup>195</sup> – so even if total preventative maintenance costs appear lower than that of other EDBs, that could be because it undertook fewer preventative maintenance activities
4. As discussed in the next section, Aurora Energy's *total* RY19 maintenance expenditure appears higher than that of other New Zealand EDBs, although this is not statistical.<sup>196</sup>

#### Trend

Aurora Energy has also assumed that growth in the network will increase expenditure by between 1.03% and 1.18% per year over the CPP and review periods. Those growth rates are sourced from the Commission's DPP for the 2020–25 period.

This assumption appears reasonable. Output growth affects preventive maintenance as growth drives the need for new assets that will need to be added to preventive maintenance and inspection schedules, increasing the workload.

Although not factored into the trend directly, Aurora Energy has applied top-down efficiency adjustments to its maintenance expenditure forecasts. These reduced the forecast preventative maintenance

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<sup>193</sup> The costs charged by Delta were incurred prior to the new FSAs being introduced. The arrangement in place at the time did not have standard job rates. Without further information, it was not possible to assess whether those costs charged by Delta – and reflected in RY19 expenditure – were efficient. Aurora Energy has noted that it expects that the new arrangements will lead to savings. These savings were not included in the preventative maintenance expenditure forecast.

<sup>194</sup> We understand that Aurora Energy had engaged KPMG to review whether this was the case or not. At the time of writing, we had not seen KPMG's review.

<sup>195</sup> Aurora Energy advised that its historical preventative maintenance expenditure reflected too few inspections and routine maintenance that had been planned but not completed. Given this, it does not appear that RY19 reflects business as usual activities.

<sup>196</sup> As noted in the third bullet point, because EDBs may adopt different asset maintenance strategies (e.g. preventative vs reactive) we opted to combine all maintenance categories for benchmarking purposes. As discussed in the next section, because Aurora Energy's total expenditure falls within confidence intervals placed around the trend line it is not possible to conclude whether that expenditure is higher than the trend as the trend is statistically uncertain.

expenditure forecasts by 1% and 3% over the CPP and review periods, respectively, which is relatively modest.

#### C.17.5.4 Benchmarking

##### Expenditure benchmarking

Benchmarking – both of partial measures and full economic benchmarking – can be used to identify efficient or inefficiency expenditure. This can involve, for instance, comparing an EDB’s expenditure to that of its peers, or a trendline reflecting average expenditure.

Although by no means definitive, benchmarking can indicate whether an EDB’s expenditure is efficient relative to chosen criteria. How useful such analysis is depends on how strong the relationship is between the performance data and the trendline identified. Such strength is captured in the  $R^2$  regression statistic – a value that shows how well the trendline fits the data, and how well the y-value (vertical axis) is related to the x-value (horizontal axis) on a plotted chart. For instance, an  $R^2$  value of zero indicates no relationship between data and trendline, while an  $R^2$  value of one indicates a perfect *positive* relationship and an  $R^2$  value of negative one indicates a perfect *negative* relationship.

Nevertheless, despite its limitations,<sup>197</sup> benchmarking can provide useful insight into whether an EDB’s expenditure appears higher, lower or aligned with its peers.

As noted above, it is difficult to compare Aurora Energy’s RY19 preventative maintenance expenditure to its EDB peers because:

- the publicly available information disclosures for other EDBs does not include that expenditure category specifically, instead capturing it within the RCI expenditure category
- EDBs adopt different maintenance practices, meaning that some may spend more on reactive maintenance and less on preventative and corrective maintenance activities, or vice versa
- EDBs may also treat costs for specific maintenance categories in different ways (i.e. by including them in different expenditure categories).<sup>198</sup>

For these reasons, it is not unreasonable to compare *total* maintenance expenditure across comparable EDBs. The four figures below compare Aurora Energy’s RY19 RCI and ARR and total maintenance expenditure to the publicly available information disclosures for 12 peers, namely:<sup>199</sup>

- **Alpine Energy:** neighbouring South Island EDB with similar ICP density and a lower UG/OH ratio
- **Counties Power:** Counties have very similar network characteristics to Aurora Energy, with similar ICP density and UG/OH ratio
- **Electra:** smaller EDB in North Island considered comparable by Aurora Energy
- **Electricity Invercargill:** small EDB in South Island with larger ICP density
- **Mainpower NZ:** neighbouring South Island EDB with similar ICP density and a lower UG/OH ratio
- **Northpower:** similar size EDB with 2/3 the number of ICPs, similar ICP density with a lower UG/OH ratio
- **Orion NZ:** large EDB in a New Zealand city hub likely to represent industry good practice

<sup>197</sup> See discussion in section G.1.

<sup>198</sup> For instance, some EDBs capture maintenance costs in the asset replacement renewal (ARR) opex category while others do not.

<sup>199</sup> This list is similar to those used by Aurora Energy when undertaking its own benchmarking. See: Aurora Energy, *Network Opex Benchmarking*, 29 April 2020.

- **Powerco:** large EDB currently undertaking an uplift in network expenditure, likely to represent similar maintenance challenges being faced by Aurora Energy
- **Unison Networks:** large EDB in a New Zealand city hub likely to represent industry good practice
- **Vector Lines:** large EDB in a New Zealand city hub likely to represent industry good practice
- **WEL Networks:** smaller EDB with very similar ICP density and UG/OH ratio
- **Wellington Electricity:** similar size EDB in the North Island with a higher ICP density.

From this list, the larger and more commercially driven New Zealand EDBs with arms-length outsourced service providers will likely provide more insight into what is efficient.

Our high-level benchmarking of aggregate opex in Appendix G.4, Figure G.14 and Figure G.16 shows that Aurora Energy's total opex is comparable to the trendline for larger NZ EDBs. This assessment also shows that Aurora Energy's aggregate opex has increased the 2013–19 period, to be the highest in the comparison for RY19.

Our draft report included some initial benchmarking of Aurora Energy's maintenance expenditure. In response, Aurora Energy provided some of its own benchmarking,<sup>200</sup> which rightly highlighted that there is a high degree of uncertainty in the opex values. We accept that there is uncertainty in the opex data provided by EDBs to the Commission, including potentially due to different cost allocation approaches and reporting treatment being used. Such differences can make comparison with a trendline or line-of-best fit difficult, and the trendline may have a relatively low R<sup>2</sup> value.

Recognising this – and consistent with Aurora Energy's benchmarking – confidence intervals were added around the plotted trendlines below, which are shown as a band around.<sup>201</sup> As a guide, we have examined where the Aurora Energy metric value falls with regards to this band. If it falls within the band, it is not possible to conclude whether Aurora Energy's expenditure is statistically different from the trend (whether higher or lower). If it does not, then it is possible.

In all benchmarking figures below, Aurora Energy's RY19 maintenance expenditure is above the fitted trend line, but within the confidence interval. The first two (Figure D.9 and Figure D.10) show that on a per kilometre and per customer basis Aurora Energy's RCI and ARR expenditure is higher than many of its peers when normalised for customer density. Once other maintenance expenditure is included, the second two figures (Figure D.11 and Figure D.12) show that Aurora Energy's total maintenance is further above the trend line, but close to or on the upper limit of the confidence intervals.

As Aurora Energy falls within the confidence intervals we cannot conclude that its expenditure is statistically higher than the trendline of comparable EDBs. However, plotting at the higher end of those intervals nevertheless suggests that RY19 maintenance *may* include some inefficiency, especially once compared to likes of Powerco – a larger utility that has more mature asset management and maintenance practices and relies on a competitive service provider market. We just cannot be certain.

Opportunities for improvement could be achieved through (among other sources):

- new and enhanced ICT systems
- improved asset management through additional asset management and operations staff (refer SONS)

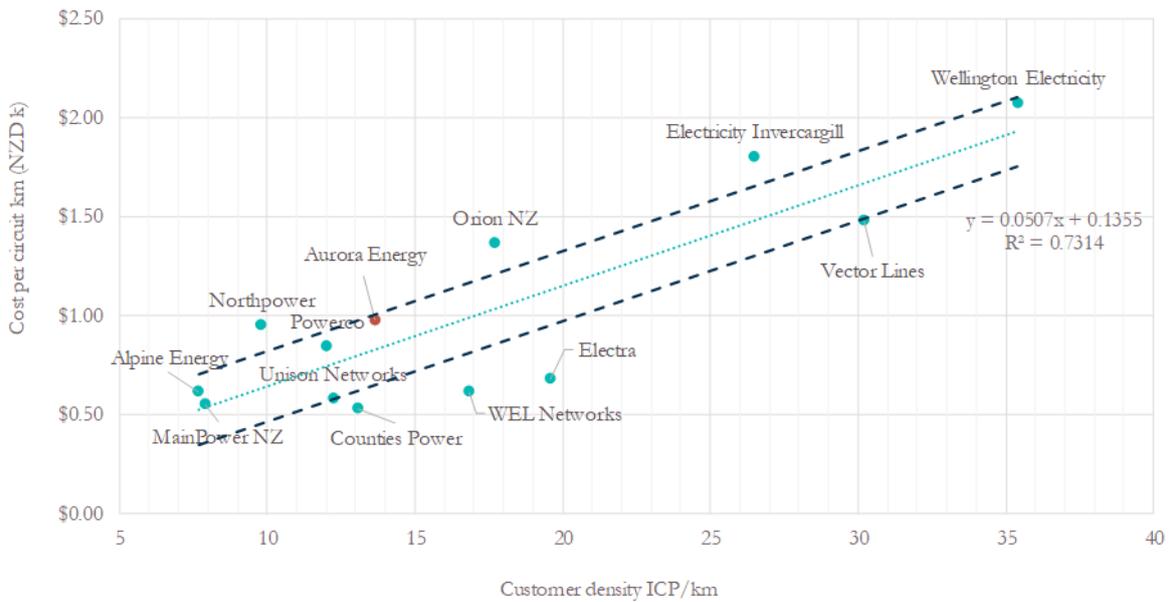
<sup>200</sup> Aurora Energy, *Network Opex Benchmarking*, 29 April 2020.

<sup>201</sup> The standard error of the fitted trendline was used to determine the confidence interval. Adding one standard error to the line gives the upper bound of the interval while removing one gives the lower bound. Generally, trendlines with relatively high R<sup>2</sup> values will have a narrow confidence interval, while those with low R<sup>2</sup> values will have a relatively wider confidence interval.

- enhanced planning through better asset condition data being retrieved through the expanded inspection program.

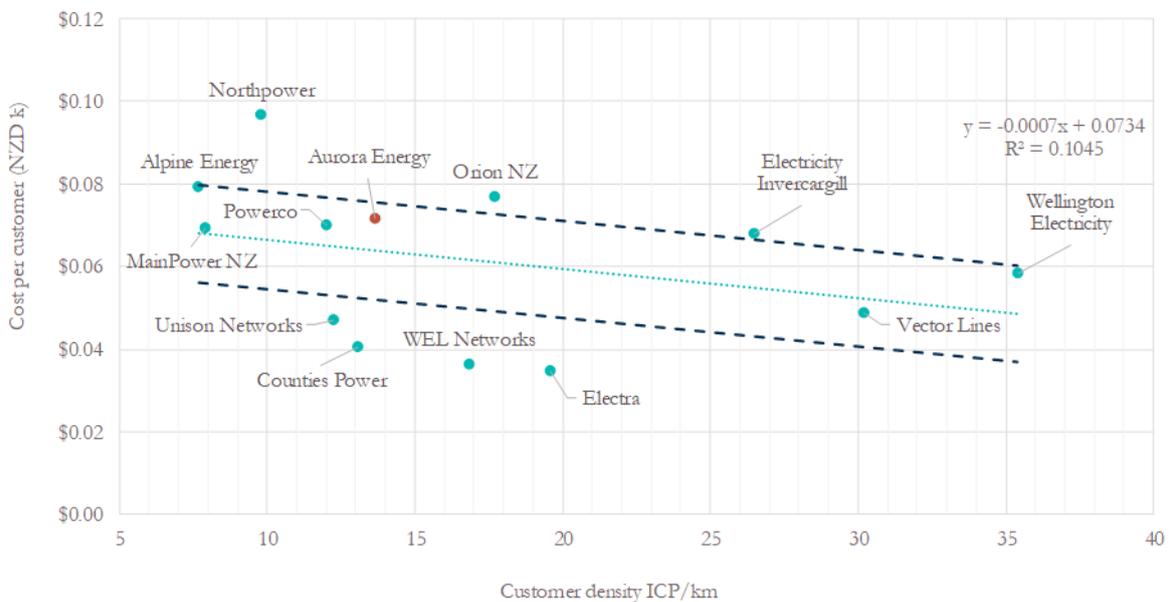
Finally, in its benchmarking Aurora Energy also looked at all New Zealand EDBs. Although we recognise that this is another valid comparison, we consider it less relevant when trying to assess whether Aurora Energy’s maintenance expenditure is efficient or not given the additional EDBs included are not directly comparable to Aurora Energy in terms of network scale and asset management maturity.

Figure C.21: RY19 RCI and ARR expenditure per circuit km vs customer density (selective EDBs, \$2020, \$000)



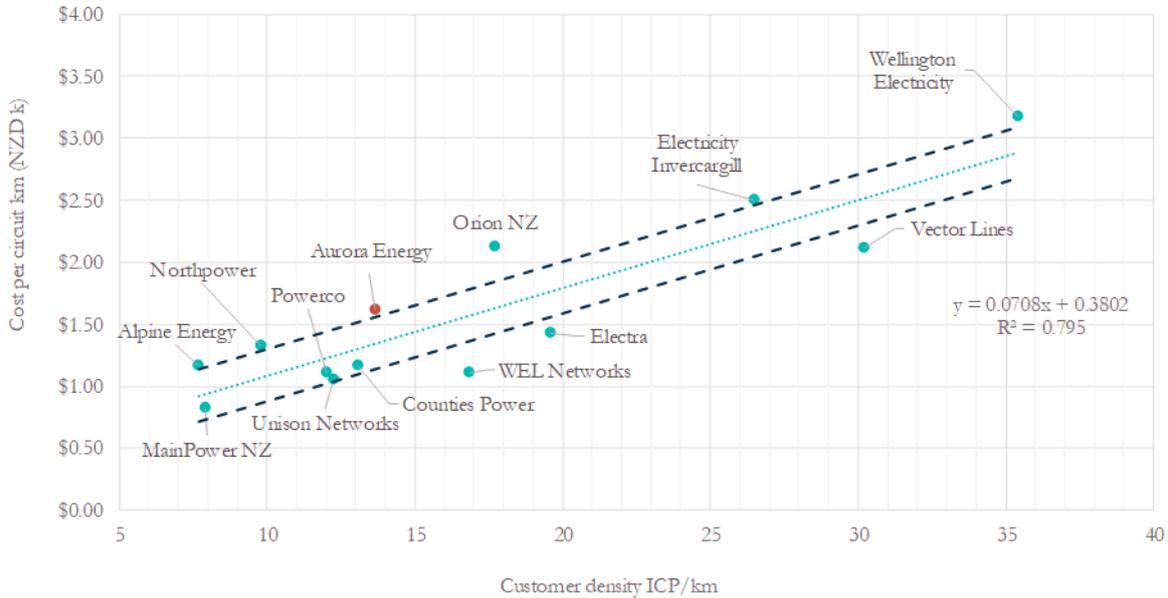
Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.22: RY19 RCI and ARR expenditure per customer vs customer density (selective EDBs, \$2020, \$000)



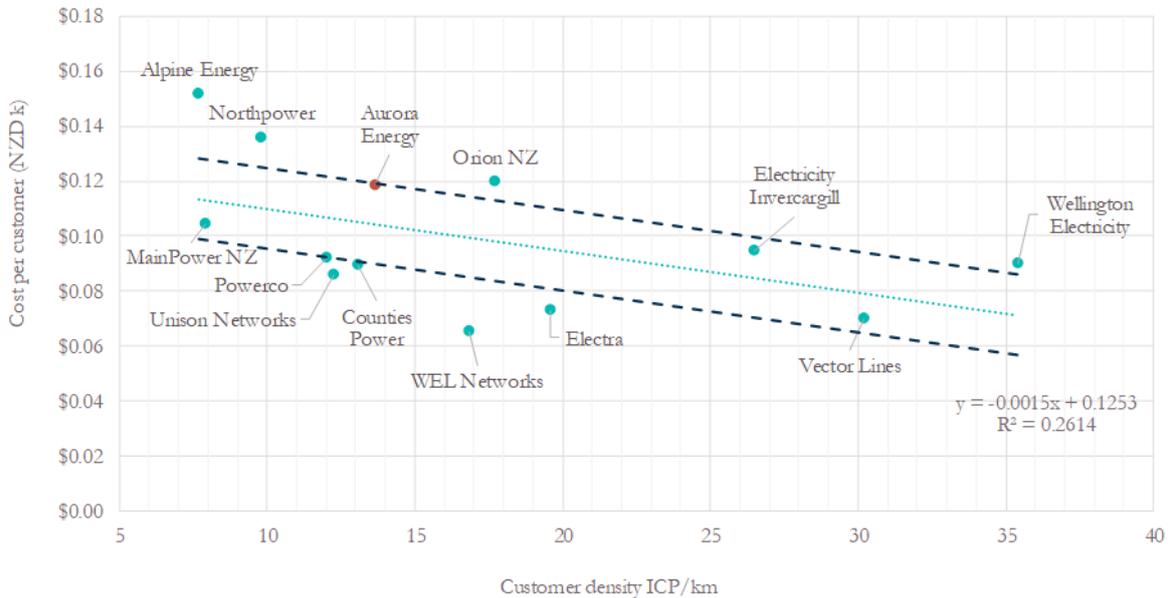
Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.23: RY19 network maintenance expenditure per circuit km vs customer density



Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.24: RY19 network maintenance expenditure per customer vs customer density



Source: Commerce Commission published data. Farrierswier and GHD analysis.

**Maintenance interval benchmarking**

As well as comparing expenditure *levels*, we have reviewed the inspection, testing and maintenance intervals Aurora Energy has nominated for different activities across the entire asset fleet, and compared them with other NZ EDBs and our experience with the Australian electricity industry. If these intervals are too long or too short, they may indicate that base expenditure is not comparable. Our comparison is contained in section F.2.5.

Overall, Aurora Energy's maintenance intervals were comparable to select New Zealand EDBs. We would expect that Aurora Energy will use improved condition assessment data obtained through its enhanced inspection programs to challenge and adjust these intervals during the CPP and review periods to ensure optimal maintenance activity and costs.

#### **C.17.5.5 Contingency factors**

No specific contingency factors have been allowed for.

#### **C.17.5.6 Interaction with other forecast expenditures**

Outcomes of expenditure undertaken in this program influences expenditure in the corrective maintenance and reactive maintenance opex programs as well as asset replacement capex; defects identified will be rectified in one of these categories, generally resulting in an increase in expenditure. By identifying defects and rectifying them in a controlled manner this should logically lead to a decrease in corrective or reactive maintenance opex over time as defects would be rectified as part of a program not on an emergency or reactive basis.

Aurora Energy has opted to capture this interaction qualitatively rather than quantitatively in its expenditure forecasts. In practice, as preventive maintenance work is completed more efficiently and completely than in past years, there should be a reduction in the number of network outages due to in-service asset failure. This would reduce both SAIDI and SAIFI as well as reactive maintenance requirements. Aurora Energy has included a notional reduction in its reactive maintenance forecast.

In addition, the projected efficiency benefits from the ICT expenditure (refer section C.16) should be reflected in the forecast expenditure. Although Aurora Energy applied some top-down efficiency improvements to the preventative maintenance expenditure forecast, we could not assess whether the timing or magnitude of these accurately reflected the expected benefits.

#### **C.17.6 Deliverability**

The forecast expenditure represents a step up from historical expenditures. Aurora Energy outsources all capital works to external contractors, with increases also require for internal resources (within SONS) to support the contractors.

Aurora Energy has undertaken modelling of the increased activities and has discussed this with its contractors, who are prepared to employ the additional staff required. Even though the increased activities require additional trained labour, we do not envisage that Aurora Energy will not be able to source the required resources. For instance, Aurora Energy has established new FSA with three contractors, with intention of ensuring work is undertaken to required timeline and quality.

The new arrangement should ensure that there are no deliverability issues for the preventative maintenance program.

It would be prudent for Aurora Energy to put in place and monitor measures that require service providers to demonstrate that performance targets and actual efficiency improvements are realised each year over the CPP and review periods.

#### **C.17.7 Our finding**

In our view, Aurora Energy's forecast preventative maintenance expenditure for the CPP and review periods appears consistent with the expenditure objective based on the information we have reviewed.

Our view is based on the following observations:

- the proposed change from a largely reactive to a more proactive maintenance approach is prudent and will likely result in lower whole of life costs – Aurora Energy has not yet modelled this, but has factored in some reduction to reactive maintenance expenditure
- the proposed asset maintenance strategies and initiatives for preventative maintenance are in line with GEIP<sup>202</sup> – and so the proposed step changes appear reasonable
- RY19 base year expenditure does not appear inefficient in a statistical sense when total maintenance opex is compared to similar expenditure incurred by comparable New Zealand EDBs – and so it does not appear to be an unreasonable starting point for applying the base, step and trend method
- improved contracting approach (with three service providers) and moving to a more structured and better approach to maintenance should lead to efficiency improvements to total maintenance expenditure over the CPP and review periods – such improvements are likely, to some degree, to be captured in the maintenance costs of comparator EDBs used in the benchmarking analysis above
- the nominated inspection, testing and maintenance intervals for routine and cycle work on the asset fleet are comparable to those used by other NZ EDBs and our experience with Australian electricity distributors (see section F.2.5)
- appropriate modelling has been undertaken to determine forecast expenditures, including using the network scale assumptions adopted by the Commission for the DPP.

Given this, we consider the preventative maintenance of \$19.0 million and \$30.5 million forecast for the CPP and review periods respectively is verified against the expenditure objective.

Importantly, although the base expenditure does not appear statistically inefficient when compared to compare New Zealand EDBs, it *may* nevertheless contain some inefficiency that would be removed through initiatives being undertaken by Aurora Energy since RY19, including the new FSAs and asset management improvements. Further reductions may also be possible to reflect on-going productivity improvements (e.g. from investment in ICT, SONS and people costs).

The top-down efficiency improvements that Aurora Energy has applied to its expenditure forecasts are relatively small over the CPP and review periods.<sup>203</sup> For instance, we would expect that the new initiatives that Aurora Energy has, or will have, in place before the CPP period should result in a greater efficiency gain than 0.5% in RY22. To understand this better, it would be sensible to review actual RY20 expenditure once this is known to determine what, if any, efficiencies may have been achieved in the first year of the FSA and use this to inform whether the base year should be adjusted or not.

Our finding is also subject to the following limitations:

- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments and reliability of reported data
- detailed analysis of the costs per maintenance activity in the RY19 may provide further insight into the efficiency base expenditure – which we have not been able to assess.

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<sup>202</sup> For instance, there appears to be a clear need to improve data integrity and asset condition information for pole tops and crossarms through an increase in inspections. There is also a need change practices. Aurora Energy identified previously uncompleted preventive maintenance, which has left some assets un-maintained (e.g. air break switches). It also noted that assets have been installed without proper consideration of equipment rating or co-ordination, which has seen potentially high-risk failures (such as uncontained explosions of electrically under-rated porcelain surge arresters).

<sup>203</sup> Specifically, Aurora Energy has proposed top-down adjustments of 0.5% per year for the first two years of the CPP period, increasing to 2.0% for RY24, 4.0% in RY25 and 6.5% for RY26 and later.

### C.17.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast preventative maintenance was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs<sup>204</sup>
- whether actual costs for preventive maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the preventive maintenance forecast for the CPP and review period are appropriate
- whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements
- reviewing the KPMG third party transaction report to the Aurora Energy Audit and Risk Committee and its findings in relation to the Delta rates.

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<sup>204</sup> To assess efficiency of RY19 expenditure, the Commission could:

- compare the volumes and unit rates of Aurora Energy's maintenance activities against its network peers
- undertake economic benchmarking, similar to what other economic regulators do (e.g. the AER)
- incorporate any efficiency improvements realised in RY20.

## C.18 CORRECTIVE MAINTENANCE (O2)

Table C.41: Verification summary – Corrective maintenance

<b>Expenditure category</b>	Corrective Maintenance	
<b>Aurora Energy CPP forecast</b>	CPP period: \$10.9 million Review period: \$17.1 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$10.2 million Review period: \$15.8 million	<b>Unverified</b> CPP period: \$0.7 million Review period: \$1.3 million
<b>Expenditure outcome assessment</b>	<p>It is appropriate to use actual RY19 opex to inform efficient base opex, but should not presume it is efficient.</p> <p>Most step changes are driven by rectification of current and projected defect backlog and enhancement of corrective maintenance activities that align with GEIP</p> <p>The reduction from improved asset condition is appropriate given significant renewal and preventative / corrective maintenance expenditure proposed</p>	<p>Although we have verified the base corrective maintenance forecast, we believe there remains scope for potential reductions due to:</p> <ul style="list-style-type: none"> <li>the benchmarking being inconclusive with regards efficiency of base expenditure</li> <li>efficiency improvements proposed by Aurora Energy being modest</li> <li>cost reduction benefits from the new contractor arrangements likely being realisable sooner than that reflected in the top-down efficiency improvements adopted by Aurora Energy.</li> </ul> <p>Although we agree that there will be more defects identified due to enhanced preventive maintenance inspections, we have not been able to verify the nominal 10% allowance for additional defects</p> <p>Scale growth does not appear appropriate for corrective maintenance over the CPP and review periods; such activities are driven more by defect correction than growth in new assets (which should be installed in a reliable condition)</p>
<b>What needs to be done</b>	<p>Work with Aurora Energy to understand the efficiency of RY19 expenditure, including how they align with GEIP</p> <p>Review of RY20 actual costs to assess the impact of the new FSA on corrective maintenance costs</p> <p>Further assess efficiency of proposed step change costs.</p>	

**Potential scope for improvement**

Better understand how corrective maintenance costs will evolve once asset management systems are improved.

### C.18.1 Project description

Corrective maintenance includes planned work relating to defects identified during inspection and preventative maintenance activities, and follow-up rectification work after a service restoration following a fault. This work addresses reliability and safety issues with the network; and excludes activities related to replacing assets and maintenance undertaken to extend the original expected in-service life of assets.

Aurora Energy acknowledged that in the past, some asset types were neglected, either as maintenance that was not planned, or planned maintenance that was not completed. The program for the CPP and review periods will include enhanced corrective actions and addressing current and future expected defect backlog, relying on more and better quality data created through the enhanced preventative maintenance activities.

This is a new maintenance category for Aurora Energy adopted for the CPP and review periods, with corrective maintenance typically combined with preventative maintenance for regulatory purposes as RCI.

### C.18.2 Cost estimate / expenditure forecast

Table C.42 shows the forecast expenditure during the CPP and review periods.

**Table C.42: Forecast expenditure – Corrective maintenance (\$2020, million)**

Item	RY22	RY23	RY24	RY25	RY26	CPP 3-year total	Review 5-year total
Expenditure	3.76	3.73	3.37	3.28	2.92	10.86	17.06

### C.18.3 Relevant policies and planning standards

Aurora Energy continues to evolve its policies and planning standards as part of its asset management journey. Key documents that we have seen that are currently influencing corrective maintenance expenditure include:

- asset management policy
- asset management plan
- vegetation management strategy
- maintenance standards
- maintenance checklists and testing forms (numerous – used to guide maintenance activities).

Aurora Energy does not yet have asset management strategy or framework documents, or maintenance strategy documents that we have seen. We understand that it intends to develop these as part of its asset management journey.

### C.18.4 Information provided

Table C.43 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.43: Information provided

Title	Reference	Date
Corrective Maintenance   Portfolio Overview Document	E-23	27 February 2020
Corrective Maintenance Forecast Model	E-24	27 February 2020
Network Maintenance (Opex)presentation	V-140	31 March 2020
D068 - Corrective Maintenance Step Changes	V-125	27 March 2020
RFI Nos D028 D060 and D098 - Maintenance opex - benchmarking	V-126	28 March 2020
<b>Provided in response to our draft report</b>		
Draft Verification Report Responses - Maintenance	PR-42	30 April 2020
Maintenance Benchmarking Memo for IV - 29 April	PR-40	30 April 2020
CM Step Changes - Post IV Review	PR-38	30 April 2020
Corrective Maintenance Forecast Model - Post IV Review	PR-37	30 April 2020
200503 Aurora network opex benchmarking	PR-48	14 May 2020

## C.18.5 Assessment of forecast method used

### C.18.5.1 Expenditure trends

Figure C.25 shows the historical and forecast expenditure for the corrective maintenance program. Historical costs increased from RY15 to RY17 before reducing to \$1.8 million in RY19. Aurora Energy proposes an average annual increase of \$1.8 million over the CPP and \$1.6 million for the Review periods from historical costs, an average annual increase of 90% on RY19 for the review period. Expenditure is forecast to rise steadily to RY22 where it reaches \$3.7 million before declining to \$2.9 million in RY26 and then further after the review period.

Figure C.25: Corrective Maintenance – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

As with preventative maintenance, Aurora Energy forecasts its corrective expenditure over the CPP and review periods using the base, step and trend method. Aurora Energy applied this method using RY19 as its base year and adding step changes. As with the preventative maintenance expenditure forecast, it also applies scale escalation.

To address potential efficiency improvements that may be achieved through other initiatives – such as the introduction of an asset management system and other ICT initiatives, establishing new FSAs with three contractors and asset renewal capex that replaces end-of-life and poor performing assets – Aurora Energy applied top-down efficiency improvements over the CPP and review periods. Forecast improvement for years after the review period were also shown.

The increase in expenditure is driven primarily by an increasing volume of activities, such as addressing new defects and remediating consumer owned poles. Forecast increases in network scale have a minor impact on the increase.

### C.18.5.2 Expenditure justification

Aurora Energy has used actual RY19 expenditure as base opex as it considers that these costs reflect business-as-usual recurrent preventive maintenance costs and were the most recently audited data available. Aurora Energy acknowledged that historical data is poor, with no formal record keeping, and any records that were kept are all paper-based or scanned data.

For the CPP and review periods, Aurora Energy has also proposed several step changes to address historical shortfalls in maintenance of some asset types, together with addressing identified and expected defect backlogs. Corrective maintenance is ongoing work, with the volume dependent upon the volume and nature of:

- defects identified during inspections
- rectification of in-service assets that have missing or damaged equipment, such as possum guards on poles,
- other initiatives, such as the Consumer Owned Pole Strategy.

Aurora Energy is proposing step changes for the following specific activities:

- consumer owned pole and line remediations
- expected new defects
- possum guard and cable guard retrofit program
- rectify backlog of cable corrective maintenance
- buildings and grounds corrective maintenance uplift
- zone substations transformer painting
- distribution buildings and grounds corrective maintenance backlog
- distribution assets repainting
- LV enclosure P160 cover replacements.

The top three step changes represent 92 per cent of the total step change increases for the CPP and review periods. The forecast changes for these step changes have been calculated on a volumetric basis.

These three step changes are considered in the following tables. As with preventative maintenance, although we have not reviewed the other step changes in detail, we have not identified any concerns with them at this stage. A previously identified step change relating to a classification correction for pole corrective maintenance costs was removed by Aurora Energy following further review.

**Table C.44: Consumer owned pole and line remediations step change**

Component	Description
Name	Consumer owned pole and line remediations
Value	CPP period: \$3.3 million Review period: \$5.6 million
Description	Aurora Energy has forecast correcting defects in – or otherwise remediating – any consumer owned poles installed prior to 1984 and with a remaining life of five years or less.
Driver	<p>As required by electricity regulations, before Aurora Energy can handover pre-1984 consumer owned poles it must ensure that they are in good condition – which requires both preventative and corrective maintenance. Historically, Aurora Energy did not specifically address the maintenance requirements for these poles, but rather attended any pole failures.</p> <p>There have been four unassisted failures in the consumer-owned population since July 2019 in a fleet of 4,000 poles. With reference to Appendix D.3, this is a higher failure rate than:</p> <ul style="list-style-type: none"> <li>• the current unassisted pole failure rate for the broader Aurora Energy pole population of approximately four poles per 10,000 per annum</li> <li>• that for comparable Australian EDBs, which target less than 1 per 10,000 poles per year.</li> </ul> <p>To address this heightened safety risk two options were considered:</p> <ul style="list-style-type: none"> <li>• do nothing – which was considered not to be in the best interest of consumers or the community due to public safety</li> <li>• remediate poles assessed as having less than five years of remaining life.</li> </ul>

Component	Description
	Consistent with the asset management approach for the Aurora Energy owned poles, the preferred option was to remediate poles in compliance with the regulations.
Volumes	<p>The work volume calculations are based on the current consumer pole population (sourced from GIS) and the proportion installed per-1984 that need rectification to be in good condition before transitioning ownership to consumers.</p> <p>Poles found to have a maximum of five years remaining life have been nominated as to be remediated in line with Aurora Energy policy, which it considers is consistent with relevant electricity regulations. Aurora Energy has noted that any further spend on these poles would not be prudent.</p> <p>Remediation of those poles was allocated evenly over the six years from RY22 to RY27. This was increased from five years following internal moderation for the expenditure forecast.</p> <p>Based on an estimated population of 4,000 poles and its knowledge of the network, Aurora Energy has assumed that 30% of the population, or 1,200 poles, will require remediation over a six year period</p>
Unit rate	<p>As no reliable cost data is available, Aurora Energy has assumed a unit rate of \$6,000 per pole. Aurora Energy considered this comparable to the \$8,000-9,000 that it uses for LV pole replacements.</p> <p>The rate is comparable to unit rates for wooden service poles included within the RIN data for Australian EDBs publicly available on the AER's website.</p>
Finding	<p><b>Verified</b> – the volume of work and unit rates do not appear unreasonable, and the approach is consistent with the asset strategy in place for the Aurora Energy owned poles (refer section D.3). The need to address the safety risk posed by the poles also appears apparent from the data provided to us.</p> <p>The Commission may want to look into this step change further, including as to whether it is appropriate for the costs to be included within the regulated cost base.</p>

Table C.45: Expected new defects step change

Component	Description
Name	Expected new defects
Value	CPP period: \$0.6 million Review period: \$0.9 million
Description	Aurora Energy has forecast a 10% increase in corrective maintenance from RY19 levels to address an expected increase in defects.
Driver	<p>Aurora Energy expects that an increased focus on preventive maintenance will increase number of defects requiring corrective maintenance, which is a logical assumption.</p> <p>Although it does not yet have a mature system for managing defects, Aurora Energy proposes implementing such a system through its ICT capex and opex</p>

Component	Description
	<p>programs. Once in place and there is more focus on preventative maintenance, it expects to find, log and then address more defects.</p>
<p>Volumes</p>	<p>Aurora Energy has assumed that there will be a 10% increase in the volume of defects requiring correction relative to RY19. No support for that assumption was provided and there was no direct quantitative link to its preventative maintenance forecast, apart from noting that it corresponds to the proposed 24% uplift in preventative maintenance.</p> <p>Even if the 24% uplift in preventative maintenance were to occur, it does not necessarily follow that there would be a 10% uplift in defects needing corrective maintenance. Enhanced inspections might simply identify more assets that do not have defects.</p> <p>Moreover, opportunities to prioritise defects, deferring those that are considered less of a priority, could offset the uplift in new defects. Aurora Energy advised that at present there is no formal backlog of defects maintained, and, other than for poles, defects are not graded.</p> <p>During RY19, Aurora Energy graded pole defects using three levels:</p> <ul style="list-style-type: none"> <li>• <b>Red</b> – poles at risk of failure under normal structural load; to be rectified within three months</li> <li>• <b>Orange</b> – poles incapable of supporting design load; to be rectified within 12 months</li> <li>• <b>Blue</b> – for poles with defects requiring repair or component replacement (crossarm/poletop); to be rectified within 24 months - this category of defect may be discontinued in the future.</li> </ul> <p>Crossarms and poletops are also graded (refer Appendix F.2.5) with crossarm defects classified D1 to D3 with short/medium/long term rectification based on the defect, and poletops graded as D4 or D5 depending upon whether the deterioration is significant or not.</p> <p>For all other assets, in general terms, defects were prioritised by safety risks and a reduction in defect volumes was considered as addressing unacceptable safety and reliability positions. The stated intention of RCI maintenance in the Aurora Energy AMP is addressing defects timely and systematically before they give rise to failure.</p> <p>Without more information we were unable to verify whether there would be a net increase in the volume of defects requiring correction over the CPP and review periods.</p>
<p>Unit rate</p>	<p>The step change implicitly assumes that the unit rates incurred in RY19 remain constant in real terms over the CPP and review periods. If deemed efficient, then that assumption is not unreasonable. However, as noted below, RY19 maintenance expenditure does not appear efficient.</p>
<p>Finding</p>	<p><b>Unverified</b> – we agree with Aurora Energy that it is likely to see an increase in the volume of defects <i>identified</i>, due to increased preventive inspections. The revised nominal assumption of 10% does not appear unreasonable, based on our engineering experience with Australian EDBs.</p> <p>However, with the introduction and implementation of the new asset management system as part of the ICT expenditure, and improved asset data, such an increase should be offset to some degree when Aurora Energy introduces a defect grading system to better prioritise defect rectification.</p>

Component	Description
	Based on the information available, we could not determine the net effect. <sup>205</sup> The Commission may wish to consider this further.

Table C.46: Possum guard and cable guard retrofits step change

Component	Description
Name	Possum guard and cable guard retrofits
Value	CPP period: \$1.0 million Review period: \$1.3 million
Description	Aurora Energy identified that many of its poles do not include possum guards and that this is contributing to recent quality standard breaches. It is proposing to retrofit possum guards on 13,440 poles (i.e. 24% of the current fleet) and cable guards on 1,500 cables (i.e. 30% of the fleet) by RY26.
Driver	<p>Aurora Energy considers that the current unguarded poles and cables pose unacceptable safety and reliability risks.</p> <p>Aurora Energy has identified a heightened fire risk due to <i>possum</i> guards being in poor condition or missing. Recent inspections have identified half of the pole population has no possum guard fitted. There is a direct safety benefit in rare instances of poles failing, and more frequent indirect safety benefits in high fire risk zones. There is also a reliability benefit from this initiative (one of the 39 reliability levers).</p> <p>The information provided does not clearly identify any specific safety risks that would be addressed by retrofitting <i>cable</i> guards, nor does it explain why it is prudent to do this work during the CPP and review periods (rather than at some other time).</p>
Volumes	<p>Aurora Energy has proposed staged retrofitting programs for possum and cable guards of six and four years respectively – which were determined after internal moderation.</p> <p>For the <i>possum</i> guard program, Aurora Energy has provided data for pole inspections that captured the condition of any existing guard and noted where guards are missing. This information supports the volume of work associated with possum guards.</p> <p>Aurora Energy estimated that half of its poles were in areas and that warranted having possum guards. Based on recent inspection data, it estimated that 48% of those poles that should have guards did not have them – leading it to estimate that 24% of all poles needed possum guards fitted.</p> <p>For the <i>cable</i> guard program, Aurora Energy estimated that 30% of its 5,000 cable terminations on poles needed guards fitted. Although no specific data was provided to support this, the assumption appears consistent with that for possum guards.</p>

<sup>205</sup> To be clear, the net effect could still be positive and could be 10%. This may occur if, for instance, the 10% uplift assumed by Aurora Energy was conservative and already factored in prioritisation stemming from a defect grading system and other initiatives.

Component	Description
Unit rate	Aurora Energy has assumed unit rates of \$150 for a possum guard, based on recent installation costs, and \$100 for a cable guard. Although we do not have any comparable rate data available, these unit rates do not appear unreasonable.
Finding	<p><b>Verified</b> – the possum guard retrofitting does not appear unreasonable given its safety and reliability benefits. The assumptions used to forecast that expenditure does not appear unreasonable.</p> <p>Although we have not been able to confirm the prudence of the cable guard retrofitting, there are likely to be efficiencies from undertaking this activity at the same time as the possum guard retrofitting and the net cost is minimal (i.e. \$0.1 million)</p>

### C.18.5.3 Key assumptions used

#### Base opex

Aurora Energy has assumed that actual RY19 expenditure for preventative, corrective and reactive maintenance provides an appropriate base cost for forecasting expenditure over the CPP and review periods. It describes this expenditure as efficient.

We have accepted the base expenditure as verified, with the same qualifications as described for preventive maintenance in sections C.17.5.3 and C.17.5.4. Although benchmarking was statistically inconclusive, there appears to be some scope to improve efficiency. As noted below, the Commission may want to consider this further.

#### Trend

Aurora Energy has also assumed that growth in the network will increase expenditure by between 1.03% and 1.18% per year over the CPP and review periods. Those growth rates are sourced from the Commission’s DPP for the 2020–25 period.

Although the assumed growth rate appears reasonable for preventative maintenance – as more inspections are required when new, growth-driven, assets are added to the fleet – this does not apply equally to corrective maintenance. Rather, corrective maintenance activities are driven by the need to address defects, which is more prevalent with older assets. Given the significant step change in corrective maintenance proposed for the CPP and review periods to address existing and expected defects, it appears inappropriate to also assume that growth in new assets will contribute in any material way to the corrective maintenance requirements over those periods.<sup>206</sup>

Aurora Energy has also assumed that asset renewals – and presumably corrective and reactive maintenance – will improve asset condition and that this will reduce corrective maintenance expenditure by 2.5% in RY22 up to 3.5% in RY24 and 4.5% in RY26. Although the assumed reductions are based on engineering judgement without any supporting information that we are aware of, the direction and magnitude does not appear unreasonable.

<sup>206</sup> Although the Commission in its recent DPP determination applied a general output trend to aggregate opex, this reflects a simplified approach suited to the lighter touch approach adopted for that process. In our view, that does not mean that the same general output trend should be applied to individual expenditure categories when a more thorough assessment of efficient opex for each category is undertaken.

Although not factored into the trend directly, Aurora Energy has applied top-down efficiency adjustments to its maintenance expenditure forecasts. These reduced the forecast corrective maintenance expenditure forecasts by 1% over the CPP and review periods, which is relatively modest.

#### C.18.5.4 Benchmarking

Benchmarking of RCI and network maintenance expenditure, including corrective maintenance, is covered in section C.17.5.4.

#### C.18.5.5 Contingency factors

No specific contingency factors have been allowed for.

#### C.18.5.6 Interaction with other forecast expenditures

Outcomes of expenditure undertaken in this program influences expenditure in the corrective maintenance and reactive maintenance opex programs as well as asset replacement capex; defects identified will be rectified in one of these categories, generally resulting in an increase in expenditure. By identifying defects and rectifying them in a controlled manner this should logically lead to a decrease in corrective or reactive maintenance opex over time as defects would be rectified as part of a program not on an emergency or reactive basis.

Aurora Energy has opted to capture this interaction with top-down assumptions rather than through a direct quantitative link between its expenditure forecasts. For instance, Aurora Energy has included – as a step change – a 10% increase in corrective maintenance in response to new defects identified through enhanced preventative maintenance. As noted above, a step up in expenditure is not unreasonable.

Aurora Energy has also recognised that improved asset condition should reduce corrective maintenance requirements over time by including through a negative trend. This is not unreasonable. Over time, as preventive maintenance work is completed more efficiently and completely than in past years – and any defect backlog addressed – there should be a reduction in corrective maintenance activities.

Similarly, rectification of more defects through the corrective maintenance program should reduce lead to fewer network outages due to in-service asset failure. This would reduce both SAIDI and SAIFI as well as reactive maintenance requirements. Aurora Energy has included a notional reduction in its reactive maintenance forecast.

In addition, the projected efficiency benefits from the ICT expenditure (refer section C.16) should be reflected in the forecast expenditure. Although Aurora Energy applied some top-down efficiency improvements to the preventative maintenance expenditure forecast, we could not assess whether the timing or magnitude of these accurately reflected the expected benefits.

### C.18.6 Deliverability

The forecast expenditure represents a significant step up from historical expenditures. Aurora Energy outsources all capital works to external contractors, with increases also require for internal resources (within SONS) to support the contactors.

Aurora Energy has undertaken modelling of the increased activities and has discussed this with its contractors, who are prepared to employ the additional staff required. Even though the increased activities require additional trained labour, we do not envisage that Aurora Energy will not be able to source the required resources. For instance, Aurora Energy has established new FSA with three contractors, with intention of ensuring work is undertaken to required timeline and quality.

We consider that the new arrangement should ensure that there are no deliverability issues for the preventive maintenance program.

It would be prudent for Aurora Energy to put in place and monitor measures that require service providers to demonstrate that performance targets and actual efficiency improvements are realised each year over the CPP and review periods.

### C.18.7 Our finding

In our view, Aurora Energy's forecast corrective maintenance expenditure for the CPP and review periods appears too high based on the information we have reviewed.

Our view is based on the following observations:

- the proposed change from a largely reactive to a more proactive maintenance approach is prudent and will likely result in lower whole of life costs – Aurora Energy has not yet modelled this, but has factored in some reduction to reactive maintenance expenditure
- the proposed asset maintenance strategies and initiatives for corrective maintenance are in line with GEIP – and so the *need* for most of the proposed step changes appears reasonable
- RY19 base year expenditure does not appear inefficient in a statistical sense when total maintenance opex is compared to similar expenditure incurred by comparable New Zealand EDBs – and so it does not appear to be an unreasonable starting point for applying the base, step and trend method
- improved contracting approach (with three service providers) and moving to a more structured and better approach to maintenance should lead to efficiency improvements to total maintenance expenditure over the CPP and review periods – such improvements are likely, to some degree, to be captured in the maintenance costs of comparator EDBs used in the benchmarking analysis above
- based on the information available, the proposed step change for new defects could not be justified against the expenditure objective
- the proposed increase in corrective maintenance to reflect scale growth over the CPP and review periods does not appear appropriate given it is defects of predominately older assets that drivers that expenditure, not new growth-driven assets being added to the fleet
- appropriate modelling has been undertaken to determine forecast expenditures.

Given this, we consider corrective maintenance of \$10.2 million and \$15.8 million forecast for the CPP and review periods respectively is verified against the expenditure objective. The \$0.7 million and \$1.3 million over the two periods respectively that we consider unverified at this stage reflects the impact of removing the expected new defects step change and the output growth trend.

Importantly, although the base expenditure does not appear statistically inefficient when compared to compare New Zealand EDBs, it *may* nevertheless contain some inefficiency that would be removed through initiatives being undertaken by Aurora Energy since RY19, including the new FSAs and asset management improvements. Further reductions may also be possible to reflect on-going productivity improvements (e.g. from investment in ICT, SONS and people costs).

The top-down efficiency improvements that Aurora Energy has applied to its expenditure forecasts are relatively small over the CPP and review periods.<sup>207</sup> For instance, we would expect that the new initiatives that Aurora Energy has, or will have, in place before the CPP period should result in a greater efficiency gain than 0.5% in RY22. To understand this better, it would be sensible to review actual RY20

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<sup>207</sup> Specifically, Aurora Energy has proposed top-down adjustments of 0.5% per year for the first two years of the CPP period, increasing to 1.0% for the following two years RY24-25, 1.5% in RY26 and 6.5% for RY27 and later.

expenditure once this is known to determine what, if any, efficiencies may have been achieved in the first year of the FSA and use this to inform whether the base year should be adjusted or not.

Our finding is also subject to the following limitations:

- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments and reliability of reported data
- detailed analysis of the costs per maintenance activity in the RY19 may provide further insight into the efficiency base expenditure – which we have not been able to assess.

### C.18.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast corrective maintenance was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs<sup>208</sup>
- whether actual costs for corrective maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the corrective maintenance forecast for the CPP and review period are appropriate
- whether the proposed costs of consumer owned pole and line remediation should be included in the regulated cost base
- whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements.

As an aside, data integrity issues and poor records on the number and type of defects identified during inspections make it difficult to efficiently manage corrective maintenance requirements. Given this, it will be important for Aurora Energy to focus on improving these records during the CPP and review periods to better inform its future maintenance planning and strategies, especially for rectification work.

Doing so may lead to additional efficiency improvements not yet reflected in the maintenance expenditure forecasts, such as by allowing Aurora Energy to defer rectification of lower priority defects without undermining safety or network operation. Corrective maintenance efficiency depends upon ensuring that defects that represent significant risks to safety and network operation are attended to quickly, while those with lower risk are properly grouped and planned to ensure that the work is done efficiently.

If not already planned, Aurora Energy should consider adopting a defect grading system together with measures to monitor backlogs and process in rectification against set timelines during the review period.

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<sup>208</sup> To assess efficiency of RY19 expenditure, the Commission could:

- compare the volumes and unit rates of Aurora Energy's maintenance activities against its network peers
- undertake economic benchmarking, similar to what other economic regulators do (e.g. the AER)
- incorporate any efficiency improvements realised in RY20.

## C.19 REACTIVE MAINTENANCE (O3)

Table C.47: Verification summary – Reactive maintenance (\$2020, million)

<b>Expenditure category</b>	Reactive maintenance	
<b>Aurora Energy CPP forecast</b>	CPP period: \$13.8 million Review period: \$22.8 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$13.3 million Review period: \$21.6 million	<b>Unverified</b> CPP period: \$0.5 million Review period: \$1.1 million
<b>Expenditure outcome assessment</b>	<p>It is appropriate to use actual RY19 opex to inform efficient base opex, but should not presume it is efficient.</p> <p>The step changes are not unreasonable.</p> <p>The reduction from improved asset condition is appropriate given significant renewal and preventative / corrective maintenance expenditure proposed.</p>	<p>Although we have verified the base preventive maintenance forecast, we believe there remains scope for potential reductions due to:</p> <ul style="list-style-type: none"> <li>the benchmarking being inconclusive with regards efficiency of base expenditure</li> <li>efficiency improvements proposed by Aurora Energy being modest</li> <li>cost reduction benefits from the new contractor arrangements likely being realisable sooner than that reflected in the top-down efficiency improvements adopted by Aurora Energy.</li> </ul> <p>Scale growth does not appear appropriate for reactive maintenance over the CPP and review periods; such activities are driven more by fault rectification than growth in new assets (which should be installed in a reliable condition).</p>
<b>What needs to be done</b>	<p>Work with Aurora Energy to understand the efficiency of RY19 expenditure, including how they align with GEIP</p> <p>Review of RY20 actual costs to assess the impact of the new FSA on reactive maintenance costs</p> <p>Consider further the assumed impact of improved asset condition.</p>	
<b>Potential scope for improvement</b>	<p>Monitor improvement in response times to support next CPP submission for period post RY24</p>	

### C.19.1 Project description

Reactive maintenance includes expenditure related to emergency and fault response, and switching in response to an unplanned event or incident that impact on normal network operations. This program helps to maintain network reliability, performance and safety through fault rectification activities. A key driver for this program is satisfying the proposed service standards and response times.

### C.19.2 Cost estimate / expenditure forecast

Table C.48 shows the forecast expenditure during the CPP and review periods.

Table C.48: Forecast expenditure – Reactive Maintenance (\$2020, million)

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Expenditure	4.64	4.62	4.56	4.51	4.43	13.82	22.76

### C.19.3 Relevant policies and planning standards

Aurora Energy continues to evolve its policies and planning standards as part of its asset management journey. Key documents that we have seen that are currently influencing reactive maintenance expenditure include:

- asset management policy
- asset management plan
- vegetation management strategy
- maintenance standards
- maintenance checklists and testing forms (numerous – used to guide maintenance activities).

Aurora Energy does not yet have asset management strategy or framework documents, or maintenance strategy documents that we have seen. We understand that it intends to develop these as part of its asset management journey.

### C.19.4 Information provided

Table C.49 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.49: Information provided

Title	Reference	Date
MOD72 Reactive Maintenance	E-13	21 Feb 2020
Reactive Maintenance Forecast Model	E-12	21 Feb 2020
Network Maintenance (Opex) presentation	V-140	31 Mar 2020
RFI Nos D028 D060 and D098 - Maintenance opex - benchmarking	V-126	28 March 2020

Title	Reference	Date
<b>Provided in response to our draft report</b>		
Draft Verification Report Responses - Maintenance	PR-42	30 April 2020
Maintenance Benchmarking Memo for IV - 29 April	PR40	30 April 2020
Reactive Maintenance Forecast Model - Post IV Review	PR-36	30 April 2020
200503 Aurora network opex benchmarking	PR-48	14 May 2020

## C.19.5 Assessment of forecast method used

### C.19.5.1 Expenditure trends

Figure C.26 shows the historical and forecast expenditure for the reactive maintenance program. Historical costs were quite flat from RY15 to RY18 at around \$4.4 million per year, with a spike of \$5.9 million in RY17. RY19 was between these two values at \$4.9 million.

Aurora Energy proposes an average annual decrease of \$0.3 million over the CPP and review periods from historical costs, a decrease of 6% on RY19. Expenditure is forecast to gently decline from RY22 to RY26 where it reaches \$4.4 million and continue declining after the review period.

Figure C.26: Reactive Maintenance – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

As with preventative and corrective maintenance, Aurora Energy forecasts its reactive expenditure over the CPP and review periods using the base, step and trend method. Aurora Energy applied this method using RY19 as its base year and adding or removing step changes. Like the other two programs, it also applies scale escalation. However, unlike those two programs, Aurora Energy has also included a negative trend to reflect improved network condition due to both the renewal and preventative / corrective maintenance programs.

The slight decrease in expenditure is driven primarily by both improved network condition trend and a negative step change for efficiencies from improved reactive maintenance practices. Forecast increases in network scale have a minor offsetting impact on the decrease.

### C.19.5.2 Expenditure justification

Aurora Energy has used actual RY19 expenditure as base opex as it considers that these costs reflect business-as-usual recurrent preventive maintenance costs and were the most recently audited data available. Aurora Energy acknowledged that historical data is poor, with no formal record keeping, and any records that were kept are all paper-based or scanned data.

For the CPP and review periods, Aurora Energy has proposed two step changes. One is for the cost of fault contractors providing a 24/7 fault / dispatch service, which will improve fault response times. The other is to reflect a modest expected improvement in field crew performance, including from the new contractual arrangements. The net impact is a slight reduction in expenditure of \$200,000 per year.

Both annual adjustments are nominal only. No supporting information was provided for these values other than being based on Aurora Energy's engineering judgement. We consider these step changes verified – in large part because, in aggregate, they are relatively minor and slightly negative over the CPP and review periods.

Unsurprisingly, reactive maintenance volumes are primarily driven the number of faults on the network, which is affected by:

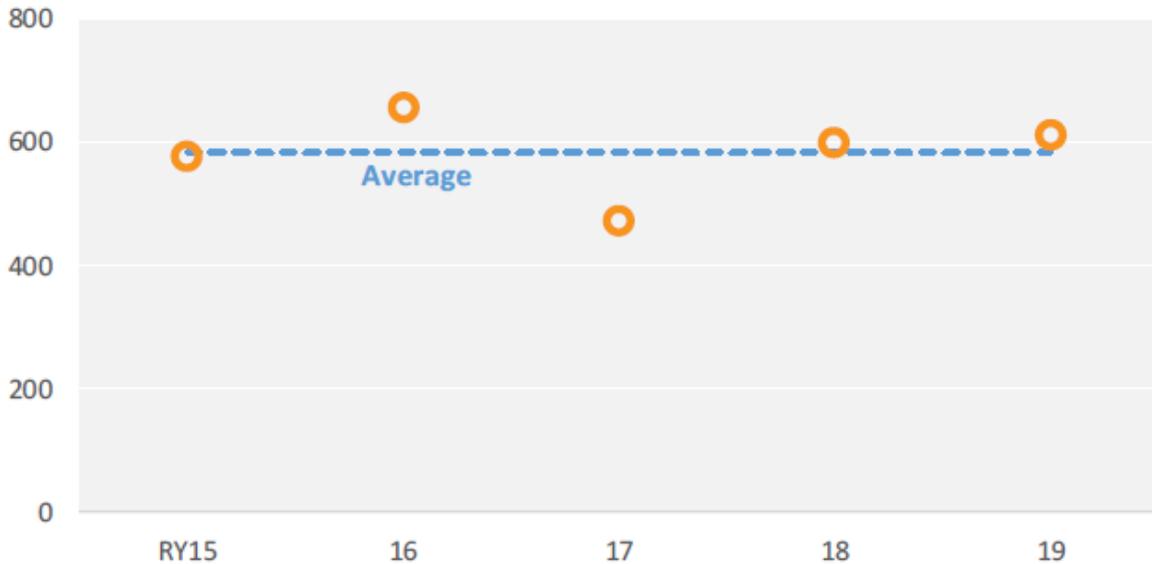
- asset age and condition
- physical location and environmental conditions
- level of automation available in the network to sectionalise the network and restore supply, and
- third-party incidents.

Aurora Energy has noted that the number of faults on the network during the period RY15 to RY19 has been relatively consistent year-on-year as shown in Figure C.27.<sup>209</sup> If implemented, the proposed renewal, vegetation management and preventative / corrective maintenance programs should reduce asset ages, improve condition, and reduce exposure to vegetation damage. These improvements should then reduce asset and vegetation related faults over the CPP and review periods relative to current levels.

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<sup>209</sup> Although the upward spike in reactive maintenance expenditure in RY17 corresponds with a downward spike in faults, this may be because there some extreme weather events in that year that were expensive to respond to but only led to a few recorded faults relative to other years.

Figure C.27: Reactive Maintenance – number of network faults



Source: Aurora Energy, POD 72 Reactive Maintenance, p. 4.

### C.19.5.3 Key assumptions used

#### Base opex

Aurora Energy has assumed that actual RY19 expenditure for preventative, corrective and reactive maintenance provides an appropriate base cost for forecasting expenditure over the CPP and review periods. It describes this expenditure as efficient.

We have accepted the base expenditure as verified, with the same qualifications as described for preventative maintenance in sections C.17.5.3 and C.17.5.4. Although benchmarking was statistically inconclusive, we consider there appears to be some scope to improve efficiency. As noted below, the Commission may want to consider this further.

#### Trend

Aurora Energy has assumed that growth in the network will increase expenditure by between 1.03% and 1.18% per year over the CPP and review periods. Those growth rates are sourced from the Commission's DPP for the 2020–25 period.

Although the assumed growth rate appears reasonable for preventative maintenance – as more inspections are required when new, growth-driven, assets are added to the fleet – this does not apply equally to reactive maintenance. Rather, reactive maintenance activities are driven by the need respond to faults, which are more common in older assets and those with deteriorating condition. Given this, including a scale trend does not appear appropriate.

Aurora Energy has also assumed that asset renewals – and presumably corrective and reactive maintenance – will improve asset condition and that this will reduce reactive maintenance expenditure by 1.5% in RY22 up to 2% in RY24 and 2.5% in RY26. Although the assumed reductions are based on

engineering judgement without any supporting information that we are aware of, the direction and magnitude does not appear unreasonable.<sup>210</sup>

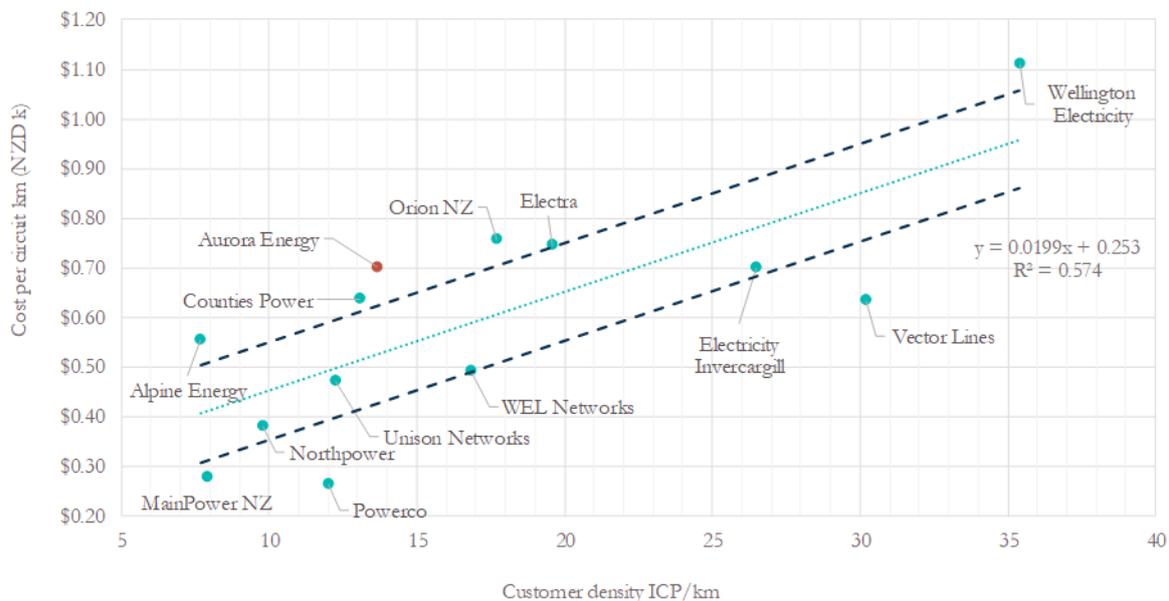
### C.19.5.4 Benchmarking

Benchmarking of *total* maintenance expenditure, including corrective maintenance, is covered in section C.17.5.4. In a similar way, Figure C.28 and Figure C.29 compare Aurora Energy’s RY19 reactive maintenance expenditure against the same 12 comparators on a per circuit kilometres and per failure rate per 100 kilometres basis.<sup>211</sup> The comparisons also use customer density as a normalising factor.

Figure C.28 shows that Aurora Energy’s reactive maintenance per circuit kilometre benchmarks well above the confidence interval, which perhaps is unsurprising giving the poor condition of many asset fleets and that Aurora Energy’s network is split between two distinct geographical locations with areas of remote access. However, it may also be explained by inefficiencies in base expenditure – which is somewhat confirmed by Aurora Energy itself proposing a negative step change for improved reactive maintenance practices and a positive step change to introduce a 24/7 dispatch service to improve response times.

However, in relation to the nominated comparable EDBs, Aurora Energy benchmarks well for reactive maintenance costs per failure rate per 100 kilometres, as shown in Figure C.29. This indicates that the field service provider was relatively efficient compared with the selected EDBs with regards to fault rectification time.

**Figure C.28: 2019 Reactive Maintenance expenditure per circuit km vs customer density (selective EDBs, \$2020, \$000)**

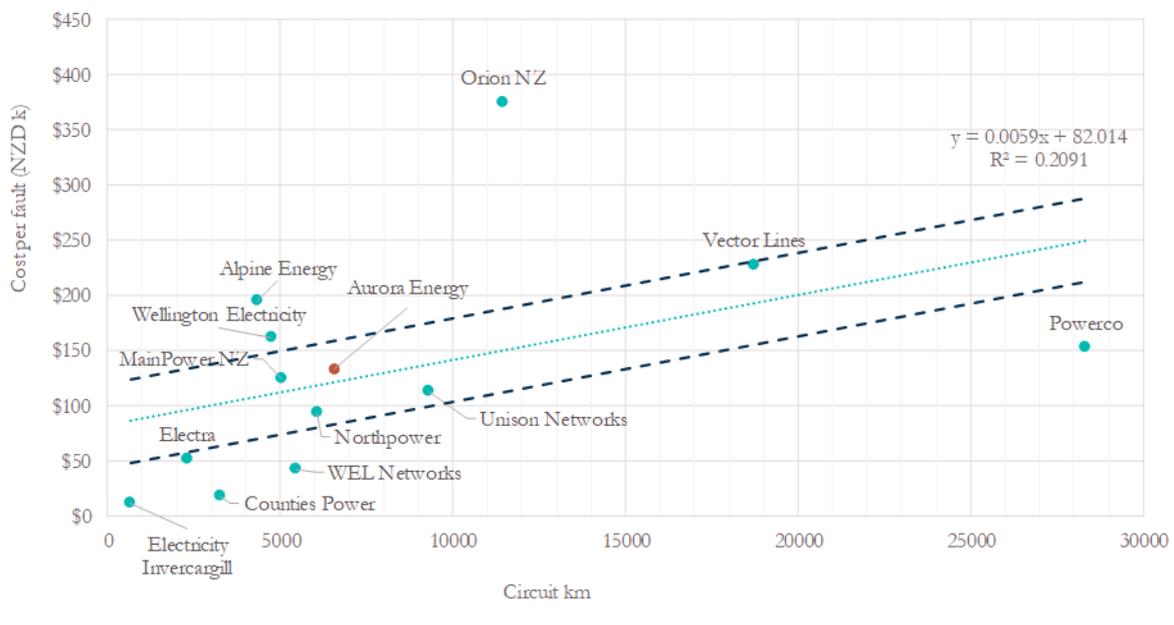


Source: Commerce Commission published data. Farrierswier and GHD analysis.

<sup>210</sup> The proposed reduction appears modest in comparison to the extensive renewal programs, although lack of reliable asset data makes it hard to be precise about potential efficiencies for the CPP and review periods. Greater efficiencies should be achievable as the asset management system is implemented and the quality of asset data improves.

<sup>211</sup> These comparators are: Alpine Energy, Counties Power, Electra, Electricity Invercargill, Mainpower NZ, Northpower, Orion NZ, Powerco, Unison Networks, Vector Lines, and WEL Networks. These comparators are similar to those adopted by Aurora Energy in its benchmarking analysis document, ‘Industry benchmarking maintenance opex’ and EDBs identified as comparable by Aurora Energy.

Figure C.29: 2019 Reactive Maintenance per failures/100 km vs customer density (selective EDBs, \$2020, \$000)



Source: Commission published data. Farrierswier and GHD analysis.

### C.19.5.5 Contingency factors

No specific contingency factors have been allowed for.

### C.19.5.6 Interaction with other forecast expenditures

Outcomes of expenditure undertaken in asset renewal, vegetation management and preventative / corrective maintenance programs influence reactive maintenance opex. Any improvement in asset age and condition or risk of vegetation will reduce the risk of faults – and therefore likely reactive maintenance requirements.

Within the reactive maintenance forecast, Aurora Energy has captured these interactions with an assumed negative trend adjustment. Ordinarily, such a reduction would be expected to align with reductions in SAIDI and SAIFI as well.

### C.19.6 Deliverability

The forecast reduction in reactive maintenance expenditure does not suggest any material deliverability concerns. Aurora Energy’s proposal for its faults contractors to provide a 24/7 dispatch service will help improve response times.

The new arrangement should ensure that there are no deliverability issues for the reactive maintenance program. As noted above for the preventative and corrective maintenance, it would be prudent for Aurora Energy to put in place and monitor measures that require the fault/outage service providers to demonstrate that performance targets and actual efficiency improvements are realised each year over the CPP and review periods.

Moreover, although the 24/7 dispatch services come at a nominal cost, Aurora Energy is also proposing that changes to the contractual arrangements will improve performance of field crews that address network faults.

### C.19.7 Our finding

In our view, Aurora Energy's forecast reactive maintenance expenditure for the CPP and review periods appears unreasonable based on the information we have reviewed.

Our view is based on the following observations:

- the proposed change from a largely reactive to a more proactive maintenance approach is prudent and will likely result in lower whole of life costs – Aurora Energy has not yet modelled this, it has factored in some reduction to reactive maintenance expenditure
- the proposal to require fault contractors to provide 24/7 dispatch services is in line with GEIP
- although RY19 reactive maintenance expenditure appears inefficient to some degree when compared to similar expenditure incurred by comparable New Zealand EDBs, this is not so in a statistical sense when looking at *total* maintenance expenditure – given our conclusions on RY19 for preventative and corrective maintenance expenditure, RY19 base year expenditure does not appear to be an unreasonable starting point for applying the base, step and trend method
- improved contracting approach and moving to a more structured and better approach to maintenance should lead to efficiency improvements to total maintenance expenditure over the CPP and review periods – Aurora Energy has included a step change that picks this up
- the proposed increase in reactive maintenance to reflect scale growth over the CPP and review periods does not appear appropriate given it is faults affected by primarily by asset age and condition that drivers that expenditure, not new growth-driven assets being added to the fleet – and so it is appropriate to include the negative trend adjustment for improving asset condition, but not the scale growth trend adjustment
- appropriate modelling has been undertaken to determine forecast expenditures.

Given this, we consider reactive maintenance of \$13.3 million and \$21.6 million forecast for the CPP and review periods respectively is verified against the expenditure objective. The \$0.5 million and \$1.1 million over the two periods respectively that we consider unverified at this stage reflects the impact of removing the output growth trend.

Importantly, although the base expenditure does not appear statistically inefficient when compared to compare New Zealand EDBs, it *may* nevertheless contain some inefficiency that would be removed through initiatives being undertaken by Aurora Energy since RY19, including the new FSAs and asset management improvements. Further reductions may also be possible to reflect on-going productivity improvements (e.g. from investment in ICT, SONS and people costs).

The top-down efficiency improvements that Aurora Energy has applied to its expenditure forecasts are relatively small over the CPP and review periods.<sup>212</sup> For instance, we would expect that the new initiatives that Aurora Energy has, or will have, in place before the CPP period should result in a greater efficiency gain than 0.5% in RY22. To understand this better, it would be sensible to review actual RY20 expenditure once this is known to determine what, if any, efficiencies may have been achieved in the first year of the FSA and use this to inform whether the base year should be adjusted or not.

Our finding is also subject to the following limitations:

- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments and reliability of reported data

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<sup>212</sup> Specifically, Aurora Energy has proposed top-down adjustments of 0.5% per year for the first two years of the CPP period, increasing to 1.0% for the following two years RY24-25, 1.5% in RY26 and 6.5% for RY27 and later.

- detailed analysis of the costs per maintenance activity in the RY19 may provide further insight into the efficiency of base expenditure – which we have not been able to assess.

### C.19.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast reactive maintenance was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether RY19 expenditure is efficient and whether it is appropriate to use the information disclosure data to benchmark it against other EDBs<sup>213</sup>
- whether actual costs for corrective maintenance in RY20 identify any efficiencies achieved through the introduction of the FSAs and whether the current top-down efficiency adjustments in the reactive maintenance forecast for the CPP and review period are appropriate
- whether further productivity improvements – beyond the top-down efficiency adjustments already included – should be factored into the forecast trend to capture expected benefits from the proposed investment in ICT systems and people or changes to contracting arrangements.

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<sup>213</sup> To assess efficiency of RY19 expenditure, the Commission could:

- compare the volumes and unit rates of Aurora Energy’s maintenance activities against its network peers
- undertake economic benchmarking, similar to what other economic regulators do (e.g. the AER)
- incorporate any efficiency improvements realised in RY20.

## C.20 VEGETATION MANAGEMENT (O4)

Table C.50: Verification summary – Vegetation management (\$2020, million)

<b>Expenditure category</b>	Vegetation management	
<b>Aurora Energy CPP forecast</b>	CPP period: \$14.1 million Review period: \$21.2 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$13.3 million Review period: \$20.4 million	<b>Unverified</b> CPP period: \$0.8 million Review period: \$0.8 million
<b>Expenditure outcome assessment</b>	<p>The vegetation strategy and standard are consistent with GEIP and provide a good and robust base for forecast work volumes in CPP and Review periods.</p> <p>The volume forecasts do not appear unreasonable</p> <p>Aurora Energy has included projected efficiency improvements in forecasts for over the CPP and review periods.</p>	<p>Benchmarking suggests that the Aurora Energy RY18 vegetation management costs are higher than other EDBs by 42–56%; but is inconclusive in identifying a potential efficiency saving.</p> <p>As a minimum, the efficiencies proposed by Aurora Energy for later in the review period (of 8.5% per year) should apply from RY22 as any efficiencies resulting from the vegetation management strategy and standard be realised by then.</p> <p>Further efficiency improvements may also be available.</p>
<b>What needs to be done</b>	In lieu of relying upon historical costs from RY18 and RY19 to determine a unit rate for the CPP and review period volumetric estimates, Aurora Energy should investigate market rates to determine an efficient cost and consider modelling costs in more detail with unit rates for specific activities.	
<b>Potential scope for improvement</b>	Market test unit rate for vegetation work, rather than relying on self-assessment of costs.	

### C.20.1 Project description

Effective vegetation management is essential to ensure the operation of the system network is not compromised by vegetation affecting the overhead lines. An important component of the vegetation management strategy is the liaisons with the tree owners, together with applying good industry practice to optimise costs whilst supporting a safe and reliable supply to customers.

To this end, the vegetation management program is to manage vegetation growing near the electricity network, including:

- inspection of affected lines and cables where the inspection is substantially or wholly directed to vegetation management

- liaison with landowners including the arrangement of access to land, issue of trim/cut notices and follow-up calls on notices
- the felling or trimming of vegetation to meet externally imposed requirements or internal policy
- administration of the database associated with notification records and agreements.

### C.20.2 Cost estimate / expenditure forecast

Table C.51 shows the forecast expenditure during the CPP and review periods.

**Table C.51: Forecast expenditure – Vegetation Management (\$2020, million)**

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Expenditure	5.40	5.01	3.67	3.60	3.51	14.08	21.19

### C.20.3 Relevant policies and planning standards

Vegetation management is undertaken generally in accordance with Electricity (Hazards from Trees) Regulations 2003 (Tree Regulations), which state that Aurora Energy is responsible for the first cut, while the tree owner is responsible for the second and subsequent cuts.

Other relevant legislation, regulation and standards includes:

- Tree (Electric Lines) Regulations 1986
- Conservation Act 1987
- Electricity Act 1992
- Government Roothing Powers Act
- National Parks Act
- NZECP 34:2001
- Resource Management Act
- ANSI A300:2008 Part 1: Pruning and Part 7: Integrated Vegetation Management
- AS 4373:2007 Pruning of Amenity Trees
- BS 3998: 2010 Tree Work.

### C.20.4 Information provided

Table C.52 presents the information that has been provided by Aurora Energy in relation to the identified program. To inform our benchmarking, we also relied upon RIN data published by the AER by Australian EDBs for the period 2014/15 to 2018/19.

**Table C.52: Information provided**

Title	Reference	Date
POD73 Vegetation Management	E-77	6 March 2020
Vegetation Management Forecast Model	E-76	6 March 2020

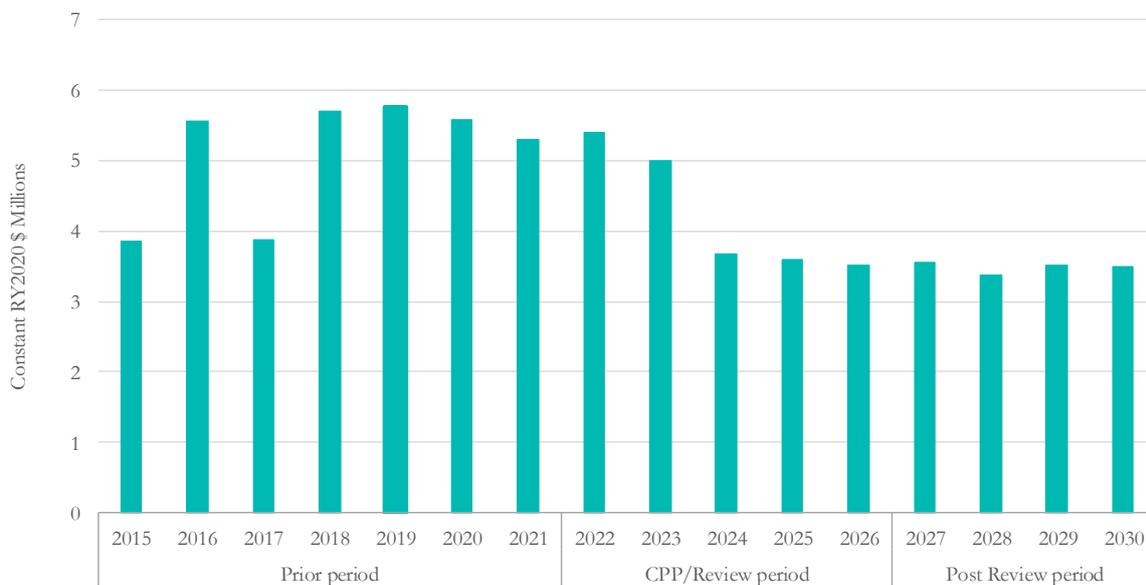
Title	Reference	Date
RFI No D260 - Vegetation Management Strategy v1.0	V-142	17 March 2020
RFI No D261 - Vegetation Management Standard v1.0	V-143	17 March 2020
P05 - Vegetation Management v0.8	V-92	26 March 2020
<b>Provided in response to our draft report</b>		
200519 Vegetation Memo for IV	PR-74	20 May 2020

## C.20.5 Assessment of forecast method used

### C.20.5.1 Expenditure trends

Figure C.30 shows the historical and forecast expenditure for the vegetation management program. Actual expenditure over the RY18 to RY23 period reflects a noticeable step change above historical levels – except for RY16, which appears to be an outlier – of about \$1.4 million per year. Expenditure reduces from RY23 to RY24 to reflect the completion of the first clearance cut.

Figure C.30: Vegetation Management – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Aurora Energy’s historical costs are based on a reactive approach to vegetation management, where cutting or other vegetation management activities were undertaken only when Aurora Energy – or its service provider, Delta – become aware that a tree does not meet the clearance requirements set out in the tree regulations.

Forecast costs are based on the introduction of cyclic cutting on a five-year cycle in all areas. Cyclic cutting is being introduced over five-year periods in both the Central Otago and Dunedin network areas, with staggered starts and finishes. Over the CPP period, the forecast costs also include expenditure to address the tree site backlog – referred to as the ‘catchup programme’ by Aurora Energy.

The catch up spend contributes \$6.7 million over the CPP and review periods. With the remaining \$7.4 million and \$14.4 million over those periods respectively reflecting the ongoing vegetation management program reflecting a five-year cutting cycle.

### C.20.5.2 Expenditure justification

The key driver is to reduce public safety risk and vegetation related outages on the network. Aurora Energy categorises vegetation affecting the distribution network as a ‘very high risk’ according to its corporate risk framework – and so started implementing a new vegetation management standard that requires a five-year cutting cycle.

Adopting a five-year cycle *is* consistent with GEIP; however, not all EDBs adopt proactive vegetation management practices. In Aurora Energy’s case, it identifies four drivers for its proposed expenditure and the change in strategy that it reflects:

- complying with tree regulations
- providing a safe network for the public, its staff and contractors
- reducing the risk of vegetation related events damaging network equipment
- providing a reliable network for customers, while meeting agreed service levels.

These are reasonable drivers. However, Aurora Energy does not appear to have compared the forecast costs of its changes in strategy to expected benefits. For instance, although it identifies improved reliability and safety outcomes, these have not been quantified, nor have any efficiencies been demonstrated.

Without establishing the benefits to be gained by the increased expenditures, the expenditure increase cannot easily be demonstrated to be prudent and hence *required* to meet the expenditure objectives. At the same time, forecasting expenditure at historical levels would also not appear prudent as this would continue the current reactive approach – which is clearly unsustainable and (in Aurora Energy’s case) inconsistent with the tree regulations.

On balance, given the historical safety and reliability concerns and the alignment with GEIP, Aurora Energy’s new vegetation management strategy does not appear inappropriate.

As the more extensive cutback takes effect, Aurora Energy expects that the costs associated with trees that require more frequent attention (12-18 months) will become the responsibility of tree owners. Aurora Energy will remain responsible for vegetation in public areas and tress regarded as “Declared No Interest” by consumers.

Tree cutting responsibility falls into two categories:

- Aurora Energy is responsible for costs associated with *all* tress in public areas and trees that are privately owned and classed as “Declare No Interest” – these trees will be managed through the routine cutting cycle detailed in the Vegetation Management Standard
- Privately owned trees where the owner has declared an interest in the management of the tree – in these instances, the cutting of the tree will follow liaison with the tree owner, and the costs associated with the cutting will be the responsibility of the tree owner.

Clearly, the categorisation of trees therefore affects the costs that Aurora Energy incurs. Other key inputs or factors relevant to those costs are:

- the affected lengths in each of the Dunedin and Central Otago networks
- the amount of catch-up to be completed in each network

- assumptions for the amount of consumer poles and private tree-owners who retain an interest in the tree management.

### C.20.5.3 Key assumptions used

#### Cost per km of exposed vegetation

Vegetation management expenditure over CPP and review periods is forecast by multiplying an assumed unit rate by the forecast vegetation quantities, split between those needed for the catchup program and those part of the ongoing maintenance of a five-year cutting cycle.

In the absence of alternative information, Aurora Energy used the average cost from RY18 per km of exposed vegetation – namely, an aggregate of liaison costs of \$536,510 and trimming costs of \$4,067,897 divided by 57.1 kilometres of exposed vegetation cut in the year. The resulting unit rate of \$98,907 per km covers trimming, customer liaison, traffic management and administrative costs. Aurora Energy was not able to provide us with any other cost information, either from its own historical records or from its current service provider, Delta. This means that the unit rate implicitly reflects the mix of activities and costs incurred in RY18 in different areas (urban/semi-rural and rural) and different regions (Dunedin/Central Otago).

Aurora Energy's assumed unit rate does not appear efficient to us for four reasons:

1. As with maintenance previously, Delta was the sole provider of vegetation services to Aurora Energy in RY18 and the contract in place at that time – and the rates charged under it – were not market tested.<sup>214</sup>
2. Delta is a related party so we cannot presume that the rates charged to Aurora Energy reflect the outcomes of arms' length negotiations.
3. Aurora Energy was not undertaking a proactive vegetation management strategy in RY18 and so it is likely that the mix of activities required over the CPP and review periods differ from those reflected in the assumed unit rate.
4. As discussed in the next section, Aurora Energy's vegetation management expenditure appears noticeably higher than that of other New Zealand EDBs.

Aurora Energy noted that cutting vegetation to the plan generated by the recently introduced vegetation management standard will drive efficiency improvements, with allowances included in the forecast for projected cost savings.<sup>215</sup>

#### Exposed vegetation quantities

Volumes comprise those needed for both the initial cutting cycle – referred to as the catch-up program – and ongoing maintenance.

Aurora Energy used a detailed analysis of estimated exposed vegetation by feeder to determine the need and then sequence both the catch up and ongoing cutting requirements:

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<sup>214</sup> The costs charged by Delta were incurred prior to the new field service arrangements being introduced. The arrangement in place at the time did not have standard job rates. Without further information, it was not possible to assess whether those costs charged by Delta – and reflected in RY18 expenditure – were efficient. Aurora Energy has noted that it expects that the new arrangements will lead to savings. These savings were not included in the vegetation management expenditure forecast.

<sup>215</sup> Aurora Energy included efficiency improvements in the forecast expenditure of 0.5% in RY22, 4% in RY23, 5.5% in RY24, 7% in RY25 and 8.5% in RY26

- **Initial cutting cycle** – the catch-up maintenance cycle was prioritised before transitioning to the routine cycle, focusing on the ‘catchup’ maintenance required on 81 out of 112 Dunedin feeders and 22/44 Central Otago feeders. Exposed vegetation (in km) was estimated using the overall route length of each feeder and the expected vegetation density along each feeder.
- **Routine maintenance cycle** – once the initial cutting cycle is complete, the vegetation management in each region is planned to begin a five-yearly routine cycle. Feeders are scheduled into a five-year program and allocated a year from 1–5, which determines when vegetation management for that feeder will be carried out in the routine cycle. Where the feeder exposed vegetation is known – i.e. for those feeders already under routine maintenance – this is used to calculate the forecast quantities per year. Where the feeder exposed vegetation is not known estimates are used based on the known quantities of other feeders.

This approach recognised different environmental and community conditions across the Central Otago and Dunedin network areas with regards to traffic management.

The assumptions used to forecast the quantity of exposed vegetation requiring management are not unreasonable.

### Top-down efficiencies

In the forecast, Aurora Energy has included allowances for efficiency improvement for the CPP and review period, with a modest projection of 0.5% in RY22, increasing each year of the review period to 8.5% in RY26.<sup>216</sup>

#### C.20.5.4 Benchmarking

Although subject to limitations,<sup>217</sup> benchmarking can provide useful insight into whether an EDB’s expenditure appears higher, lower or aligned with its peers.

Publicly available vegetation management data does not give a complete view of the vegetation management practices and cost reporting of comparable EDBs. The information disclosure information provides the length of each EDB’s network that is affected by vegetation, and the annual spend, but not the amount of affected length that is addressed (i.e. cut) each year. Consequently, a straight-forward comparison of costs per affected length may not be valid.

As an illustration, Figure C.31 compares Aurora Energy’s vegetation costs per overhead circuit kilometre with selected EDB peers for the five-year period RY15–19, but only as an indication as to the efficiency or otherwise of the Aurora Energy costs.<sup>218</sup> Overhead circuit length was used to normalise results. The chart retains the same comparator EDBs as that used above for maintenance and indicates that Aurora Energy’s vegetation management costs appear noticeably high than that for other EDBs – about 56% above the trend line and 42% above the upper confidence bound.<sup>219</sup>

The observation remains even if we use SAIDI related to outages caused by vegetation as an alternative normalising factor – as shown in Figure C.32. Using vegetation affected density as a normalising factor –

<sup>216</sup> These efficiency improvements in the forecast expenditure are nominal allowances of 0.5% in 2022, 4% in 2023, 5.5% in 2024, 7% in 2025 and 8.5% in 2026. To date, we have not received any information supporting these allowances, particularly to understand why the RY22 allowance is so modest.

<sup>217</sup> See discussion in section G.1.

<sup>218</sup> Average costs over RY15–RY19 were used to compensate for utilities being at different parts of their cutting cycles.

<sup>219</sup> These comparators are: Alpine Energy, Counties Power, Mainpower NZ, Northpower, Orion NZ, Powerco, Unison Networks, Vector Lines, and WEL Networks. These comparators are similar to those adopted by Aurora Energy in its benchmarking analysis document, ‘Industry benchmarking maintenance opex’.

as shown in Figure C.33 – does not help the analysis because Aurora Energy becomes an outlier in terms of both cost and the density (i.e. both axes).<sup>220</sup>

However, the *scale* of the difference between Aurora Energy’s data point and that for other EDBs does not appear realistic given what we know about the networks. Although the benchmarking suggests that Aurora Energy’s vegetations costs are significantly higher than the selected EDB peers, the R<sup>2</sup> of the trendlines are very low – indicating that there is little relationship between the spend per overhead kilometre and overhead circuit length or related SAIDI *based on the data points shown*. This may be due to Aurora Energy being an outlier – for, if it were removed from the regressions used to determine the trendlines, then the R<sup>2</sup> values improve noticeably.<sup>221</sup>

Other contributory factors to the low R<sup>2</sup> value are:

- variance in vegetation density by location (urban and rural)
- different strategies such as severity of cut, and level of consumer pays
- variance in vegetation status (first cut or routine cut).

For this reason, the benchmarking charts are somewhat inconclusive in *quantifying* any potential efficiency improvement relative to other NZ EDBs.

Given these challenges, we also compared Aurora Energy’s vegetation costs against those of Australian EDBs using RIN data published by the AER. As shown in Figure C.34,<sup>222</sup> this comparison suggests that Aurora Energy’s vegetation costs *are* consistent with that of Australian EDBs – somewhat in contrast to that of the New Zealand benchmarking. Although care should be taken when interpreting these results in particular,<sup>223</sup> the chart suggests that the New Zealand comparison may be affected by factors not readily adjusted for using the data available. For instance,

- in considering total circuit length, the ratio of overhead to underground is important – for that reason, our indicative Australian EDB comparison has excluded CitiPower, as this is an urban distributor in Melbourne with a high proportion of underground
- together with the overhead to underground ratio, the nature of the EDB – as shown in Figure C.34, EDBs below the trendline are generally rural, while those above are urban, suggesting that additional factors such as traffic control may influence cost comparisons.

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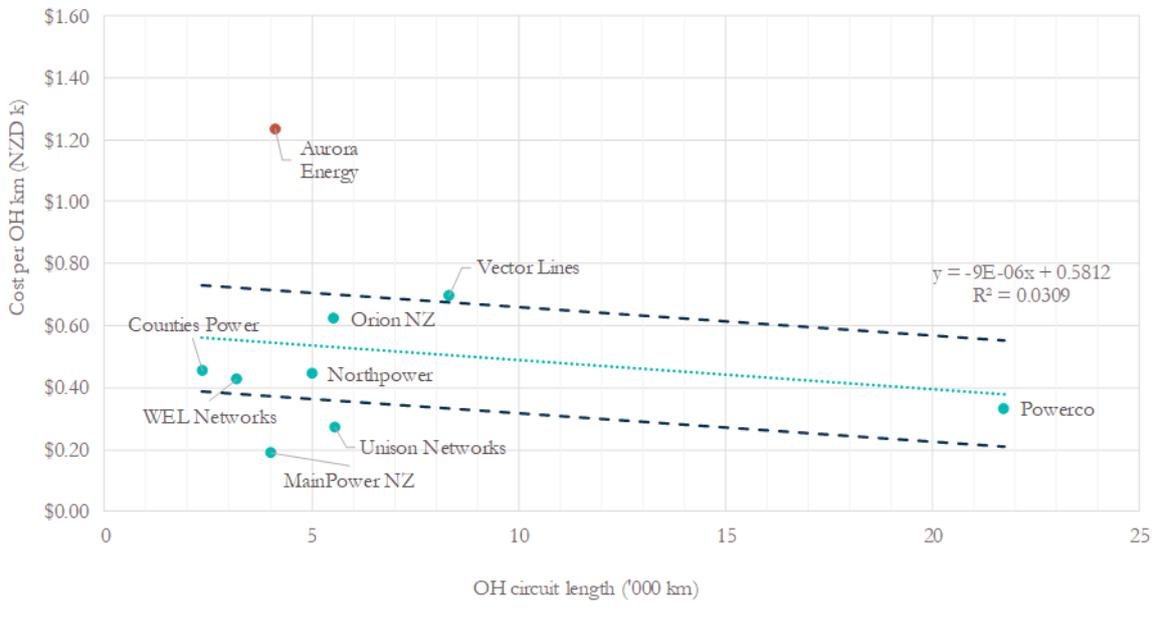
<sup>220</sup> We note there are some differences in the public reporting of vegetation-affected circuit length by the New Zealand EDBs, which may contribute to the result.

<sup>221</sup> By way of example, the R<sup>2</sup> for the trendline in Figure C.34 is 0.0374 with Aurora Energy included and 0.2313 with it removed.

<sup>222</sup> As with the New Zealand EDB benchmarking, we used five-year average costs to address the cycles for the different Australian EDBs.

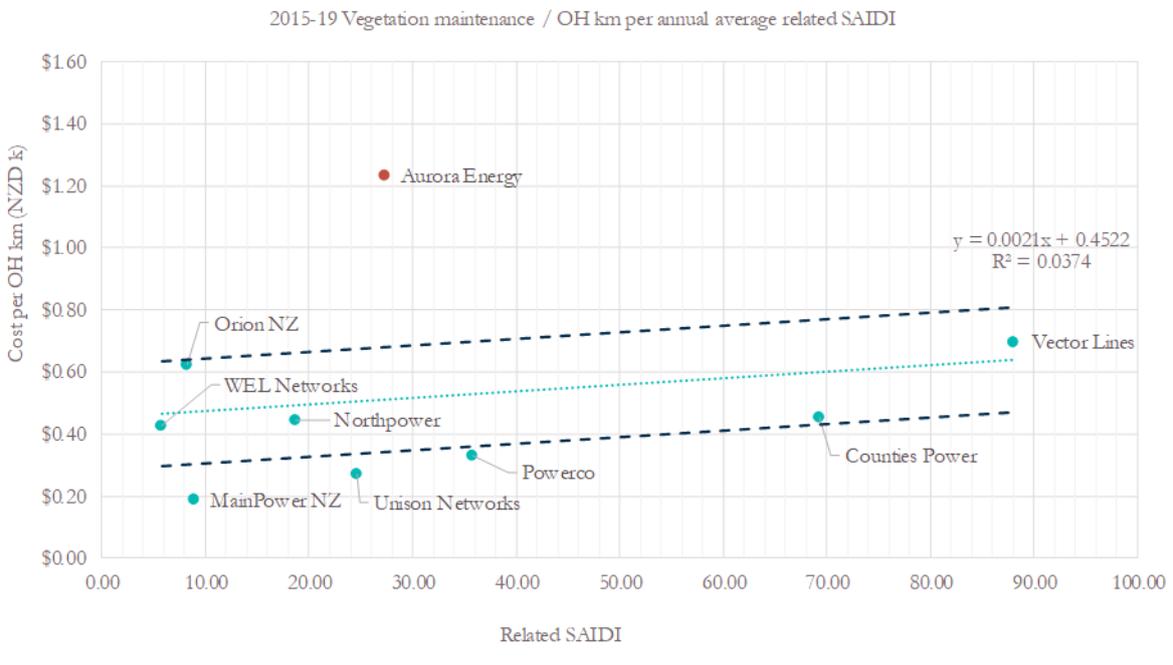
<sup>223</sup> For instance, vegetation management data is reported against different reporting obligations across the Australian and New Zealand jurisdictions and so the reported costs may not be comparable. Moreover, different operating environments may also make direct comparisons inappropriate unless these differences are adjusted for in some way.

Figure C.31: RY15–RY19 vegetation management per overhead circuit km vs overhead circuit length (\$000, \$2020)



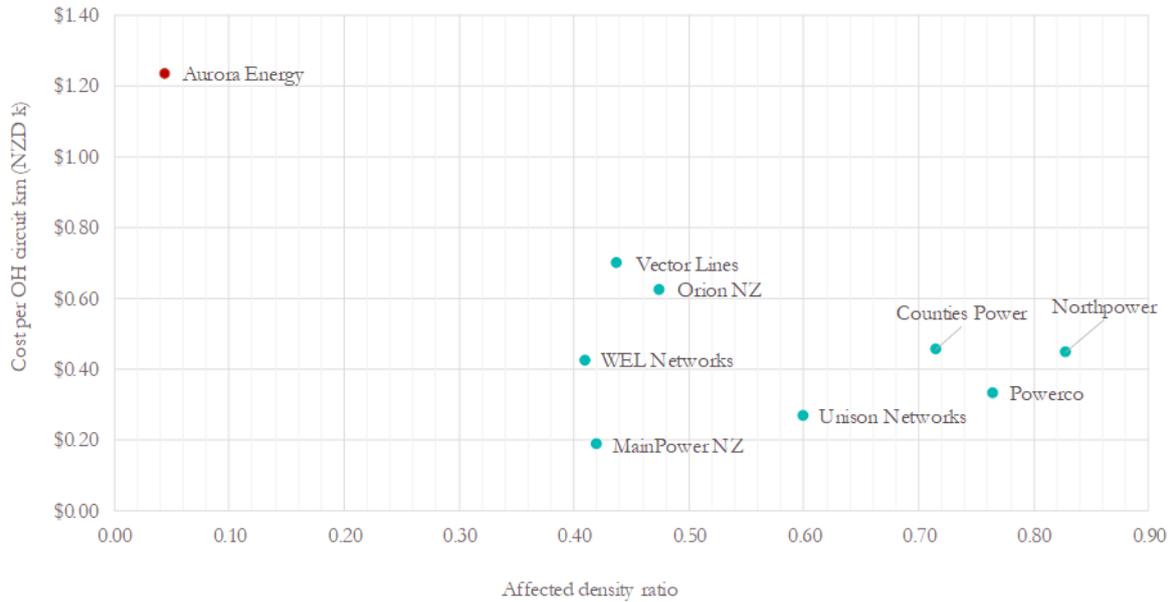
Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.32: RY15–RY19 vegetation management per overhead circuit km vs average annual related SAIDI (\$000, \$2020)



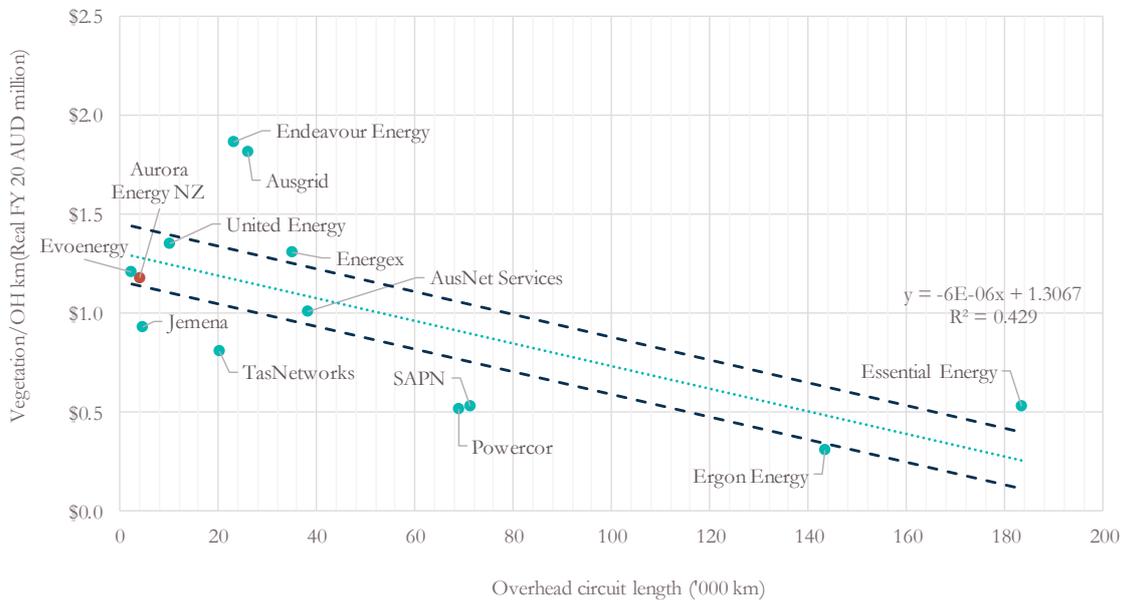
Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.33: RY15–RY19 vegetation management per circuit km vs affected density (\$000, \$2020)



Source: Commerce Commission published data. Farrierswier and GHD analysis.

Figure C.34: 2015–19 vegetation management per OH circuit km vs OH circuit length (AU\$million, \$2020)



Source: Commerce Commission published data for Aurora Energy. AER published data for Australian EDBs. Farrierswier and GHD analysis.

- (a) Aurora Energy cost data converted to Australian dollars with a notional exchange rate of 1 AUD to 1.05 NZDs. Higher or lower exchange rates will affect this comparison.

As part of auditing Aurora Energy’s related third-party transactions for 2019, KPMG reviewed vegetation costs and concluded:<sup>224</sup>

*We compared Aurora with the most comparable networks being those in the South, or only the lower South Island. Both of these comparisons show that Aurora’s ratio of expenditure is below the average, and therefore we can conclude that vegetation management services were at a value no greater than arms length.*

As reported by Aurora Energy, KPMG’s benchmarking relied upon a cost per kilometre comparison as the primary benchmark. Based on data available for total vegetation spend, length of overhead line, and the length of overhead requiring vegetation management, Aurora Energy advised that KPMG generated comparative rates as shown in Table C.53.

**Table C.53: Comparison of vegetation costs per km**

Utility	Comparative cost per km
Aurora - Vegetation management expense per km	1,309
NZ average - vegetation management expense per km	1,394
South Island average - vegetation management expense per km	1,843

Nevertheless, the significantly higher costs incurred by Aurora Energy suggests that there is room for improvement. From a review of the performance of Delta during RY20, which was the first full year of the FSA, an improvement in a broad set of metrics<sup>225</sup> was achieved, with the annual cost being \$5.43 million or approximately 10% lower than the RY19 costs of \$6.04 million.

#### C.20.5.5 Contingency factors

No contingency factors have been included in the forecast expenditures.

#### C.20.5.6 Interaction with other forecast expenditures

A stated benefit is a reduction in vegetation related faults and hence an improvement in safety outcomes and reliability of supply. Although Aurora Energy has factored in some impact on planned SAIDI from vegetation management expenditure, it has not done so for unplanned SAIDI or SAIFI. Aurora Energy stated in response to questioning that transitioning to a five-year cutting cycle will improve reliability.

Such improvement will also likely reduce reactive and corrective maintenance requirements as fewer vegetation related outages leads to fewer callouts and damage to network assets. Neither of these links appear to have been reflected in the respective expenditure forecasts.

### C.20.6 Deliverability

The forecast expenditure represents a step up from historical expenditures. Aurora Energy has indicated that the increased field activity can be provided by its external contractor, Delta, while increases in the SONS (see opex program review at D.20) will also be required.

<sup>224</sup> KPMG quote provided in Aurora Energy, *Memo – Vegetation management forecast*, 19 May 2020, p. 1.

<sup>225</sup> These metrics include site assessments, number of trees trimmed or cut, meters cut and the average number of cutting operations per day.

Aurora Energy has modelled the increased activities and has discussed this with Delta, who – we understand – is prepared to employ the additional staff required. Aurora Energy considers that Delta is being asked to undertake more extensive work for the same unit rate – and therefore will be under pressure to find cost efficiencies. It also considers that the higher level of urban work will impose pressure on Delta to deliver the program efficiently. This, and the possibility of being replaced as preferred contractor if the work is not delivered to the required standards, are seen by Aurora Energy as creating market pressure on Delta to provide an efficient service.

Even though the increased activities require additional trained labour, we do not envisage that Aurora Energy will not be able to source the required resources. Under the current FSA with Delta, Aurora Energy could look to alternative contractors if Delta does not deliver agreed performance outcomes or that agreement reaches its two-year anniversary. Such contractual renewal provides Aurora Energy an opportunity to find alternative or additional contractual resources if Delta is unable to deliver the volume of work required.

Finally, Aurora Energy also notes that the auditing of vegetation work is currently undertaken by Delta. In our view, this arrangement introduces at least a perceived conflict of interest and does not reflect GEIP for identifying and achieving efficiencies in cost or delivery. We agree with Aurora Energy that it should assume more control of the auditing to ensure that the vegetation management standard is being complied with and cost and delivery efficiencies are being realised.

### C.20.7 Our finding

In our view, Aurora Energy's forecast vegetation management for the CPP and review periods appears too high based on the information we have reviewed.

Our view is based on the following observations:

- transitioning to a five-year cutting cycle is consistent with good industry practice and is appropriate to meet the regulatory requirements
- the proposed unit rate for undertaking the work – of \$98,907 – is based on RY18 expenditure that appears inefficient when compared to other New Zealand EDBs, indicating that the unit rate is also high
- apart from the unit rate, appropriate modelling has been undertaken to determine the forecast expenditure.

As shown above, Aurora Energy's vegetation management costs appear between 42–56% higher than that of other New Zealand EDBs – suggesting that there is some room for improvement. However, it is not clear how much, if at all, operating environment factors or inconsistent reported data are contributing to this difference.

Nevertheless, Aurora Energy has recognised that there *is* some room for improvement by proposing top-down efficiencies starting at 0.5% in RY22 and increasing to 8.5% in RY26. The starting point appears modest to us. Absent other information, it is unclear why Aurora Energy could not realise efficiencies of at least 8.5% per year from the *start* of the CPP and review periods, especially given that:

- Aurora Energy's vegetation management strategy and standard will have been in place since RY21
- the credible threat of Aurora Energy going to market for vegetation management services under its new contracting arrangements should introduce some competitive tension to the costs charged by

Delta (or whatever service provider or providers Aurora Energy ends up engaging) by the start of the CPP and review periods<sup>226</sup>

- Delta achieved a 10% saving in costs for RY20 compared with RY19 and improved performance across a broad range of metrics, including length of circuit cut, number of trees trimmed and cut, cutting operations and site assessments completed.

Reducing the proposed unit rate by 8.5% reduces forecast expenditure by \$0.8 million to \$13.3 million over the CPP period, or by \$0.8 million to \$20.4 million over the review period. As noted below, the Commission may consider further what, if any, efficiency adjustments should be made Aurora Energy's proposed unit rate.

Despite our view on efficiency, the proposed strategy appears prudent to us based on the information reviewed. Aurora Energy's vegetation management strategy and standard are comprehensive and consistent with GEIP. This approach provides an excellent platform going forward to complete the first-pass on all affected sections, and aim to reduce future work volumes through prudent cutting of vegetation to allow a five-year cycle, instead of the present 12–18 months – which should reduce lifecycle overall costs, in theory.

Our finding is also subject to the following limitations:

- it is not clear that the expected benefits from the change in strategy justify the forecast costs – if not, then it may not be prudent to implement the strategy at this time
- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments, have different overhead or underground configurations, or report data differently
- detailed analysis of the costs per maintenance activity in the RY19 may provide further insight into the efficiency of base expenditure – which we have not been able to assess.

### C.20.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast vegetation management was generally sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether RY18 expenditure – which was used to determine the unit rate – is efficient and whether it is appropriate to use the information disclosure data to benchmark that expenditure against other EDBs
- whether additional year on year productivity improvements should be factored into the forecast to reflect performance improvements and associated reduced costs from the start of the CPP period, rather than gradual improvements as currently proposed by Aurora Energy.

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<sup>226</sup> Aurora Energy advised that Delta is only currently engaged for the next two years and it may go to market after this point if not satisfied with the services provided. This arrangement – and the credible threat of going to market – should drive efficiency improvements from Delta from the start of the CPP period, rather than later.

## C.21 SYSTEM OPERATIONS AND NETWORK MANAGEMENT (SONS) (O5)

Table C.54: Verification summary – System Operations and Network Support (\$2020, million)

<b>Expenditure category</b>	SONS	
<b>Aurora Energy CPP forecast</b>	CPP period: \$49.2 million Review period: \$80.4 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$47.6 million Review period: \$77.1 million	<b>Unverified</b> CPP period: \$1.6 million Review period: \$3.3 million
<b>Expenditure outcome assessment</b>	Benchmarking of SONS costs in 2019 shows that Aurora Energy is comparable to New Zealand EDB peers of similar size and asset management maturity.  Evidence that Aurora Energy ELT has reviewed and limited growth in FTEs since July 2017 to only fill roles required during the CPP and review periods.	We do not consider that it is appropriate to apply a network growth rate as growth in number of network assets does not drive increase in SONS work, at least over the timeframe being considered.  We consider that the step change for insurance is too high.
<b>What needs to be done</b>	Work with Aurora Energy to understand the scope for future efficiency improvements from the significant proposed investment in systems, people and processes  Assess consistency between capitalised and expensed SONS expenditure.	
<b>Potential scope for improvement</b>	Monitor effectiveness of SONS to support and deliver the ambitious renewal and other expenditure programs proposed.	

### C.21.1 Project description

SONS costs Aurora Energy’s internal costs to manage and operate the network, including management of all network capex and opex programs. Functions carried out include:

- asset management and planning
- operations and network performance
- works programming and service delivery
- operational technology
- customer initiated works and contact centre
- planning and delivery process design.

Key focus areas for the business include:

- improving Aurora Energy’s asset management capability by achieving ISO55001 certification by RY23
- preparing for the anticipated impact of renewable generation and load – such as solar PV and electric vehicles – on the distribution network
- preparing for delivery of increased works programs.

This work will be supported by initiatives in the ICT capex and opex program (refer section C.16).

### C.21.2 Cost estimate / expenditure forecast

Table C.55 shows the forecast expenditure during the CPP and review periods.

Table C.55: Forecast expenditure – SONS (\$2020, million)

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Expenditure	15.94	17.17	16.03	15.85	15.37	49.15	80.37

### C.21.3 Relevant policies and planning standards

Aurora Energy continues to evolve its policies and planning standards as part of its asset management journey. Key documents that we have seen that are currently influencing SONS expenditure include:

- asset management policy
- asset management plan
- vegetation management strategy
- maintenance standards
- maintenance checklists and testing forms (numerous – used to guide maintenance activities).

Aurora Energy does not yet have asset management strategy or framework documents, or maintenance strategy documents that we have seen. We understand that it intends to develop these as part of its asset management journey.

### C.21.4 Information provided

Table C.56 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.56: Information provided

Title	Reference	Date
POD80 - SONS	E-35	28 February 2020
MOD80 - SONS Forecast Model	E-82	9 March 2020
P17 - Non Network Opex - SONS and people costs (final) - Post Workshop	V-120	27 March 2020
<b>Provided in response to our draft report</b>		
Appendix 1 - Major SONS and People Step Changes and Guide to Supporting Information	PR-23	23 April 2020
Appendix 2, 3, 4 and 5 - SONS People - App 2 to 5	PR-16	23 April 2020
Attachment 1 - Revised SONS BST Forecasting Model	PR-21	23 April 2020
Attachment 2 - Revised PEOPLE BST Forecasting Model	PR-20	23 April 2020

Title	Reference	Date
Attachment 3 - Summary of Non-network forecast changes since March 19 workshop	PR-26	23 April 2020
Attachment 4 - IV CPP Cost Forecasts	PR-27	23 April 2020
Attachment 5 - Non-network Opex - SONS and People Workshop Slides	PR-15	23 April 2020
Attachment 6 - Aurora Energy Remuneration Standard	PR-17	23 April 2020
Attachment 7 - IV Remuneration Benchmarking Analysis - Strategic Pay (SP10) Analysis	PR-18	23 April 2020
Attachment 8 - Network Evolution Model	PR-19	23 April 2020
Attachment 9 - Insurance Forecast spreadsheet	PR-24	23 April 2020
Attachment 10 - Crombie Lockwood Report	PR-25	23 April 2020
Memo Responding to Insurance Step Changes	PR-71	16 May 2020
Memo Responding to Insurance Step Changes - 28 May 2020	PR-86	28 May 2020

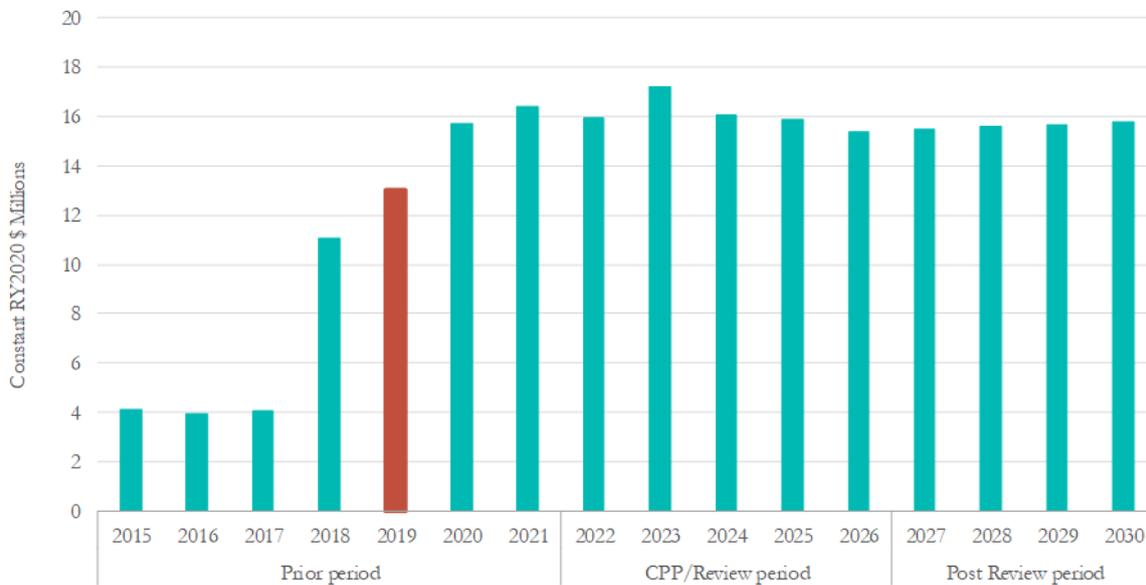
## C.21.5 Assessment of forecast method used

### C.21.5.1 Expenditure trends

Figure C.35 shows the historical and forecast expenditure for the SONS program. Expenditure in RY17 is forecast to increase from \$4.1 million in RY17 to \$15.7 million in RY20, an increase of \$11.3 million, or 276%. This step up is not a surprise given that in RY17 Aurora Energy effectively had no SONS staff.

From RY20 onwards SONS expenditure largely remains flat, with a slight rise in RY23 to cover the expected costs of a second CPP application for the five years from RY25 (of \$1.4 million over RY23 and RY24). This rise is followed by a gentle reduction through to RY26.

Figure C.35: SONS – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Aurora Energy forecasts its expenditure over the CPP and review periods using the base, step and trend method. Aurora Energy applied this method using RY19 as its base year, making two minor negative accounting adjustment, and adding step changes. It also applies scale escalation.

The increase in expenditure is driven by the recruiting resources to establish and deliver the SONS function. Forecast increases in network scale have a minor impact on the increase.

### C.21.5.2 Expenditure justification

The forecast expenditure represents a significant step up from historical expenditures. The key driver for this was the need for Aurora Energy to establish its own asset management capability rather than rely on Delta.

Prior to July 2017, Aurora Energy paid an annual fee to Delta to provide asset management and SONS services. Aurora Energy effectively had no SONS staff of its own. Following a review by Deloitte – which recommended a new operating structure and governance arrangements for asset management activities – Aurora Energy has identified and sought to fill the roles needed so it could develop and implement new asset management systems and support the expenditure programs over the CPP and review periods.

Within this, Aurora Energy identify three specific drivers for its SONS expenditure over the CPP and review periods, namely:

- improvement in asset management capability to drive better network performance, deliver a safe and more reliable network and achieve lower costs through an extended field services arrangement
- a co-ordinated approach to the management of network operations and performance, customer engagement and works delivery
- preparation of the distribution network for the anticipated increase in penetration of photo-voltaic (PV) installations and electric vehicles (EV).

Most of the identified roles have now either been filled or committed to, with many of these costs reflected in the RY19 base year expenditure.

Relative to that expenditure, Aurora Energy proposes \$13.4 million worth of step changes over the CPP period, or \$20.6 million over the review period. The major step changes are:

- recruiting further resources to establish its asset management capability
- preparing a CPP over RY23 and RY24
- additional technology costs
- additional field audit costs
- supporting its network evolution plan
- increasing insurance costs.

These six step changes are considered in the following tables. Although we have not reviewed the other step changes in detail (which sum to \$0.1 million in the CPP and \$0.3 million in the review period), we have not identified any concerns with them.

**Table C.57: Staff costs step change**

Component	Description
Name	Staff costs
Value	CPP period: \$7.2 million Review period: \$11.9 million
Description	Resource requirements for ongoing development of the business to improve asset management maturity and customer engagement
Driver	<p>With separation from Delta in July 2017, Aurora Energy required structural reorganisation to manage and operate the distribution network and to bring in-house business support previously done by Delta.</p> <p>Key drivers were:</p> <ul style="list-style-type: none"> <li>• Deloitte report identified need for business separation</li> <li>• WSP report – independent report on state of the network</li> <li>• ACML AMMAT assessment has identified areas for improvement to meet ISO55001.</li> </ul> <p>Three key areas of focus:</p> <ul style="list-style-type: none"> <li>• asset management maturity</li> <li>• supporting the step changes in investment</li> <li>• preparations for network evolution.</li> </ul> <p>There is also a need to further develop and maintain Aurora Energy’s specific standards and procedures required as a result of business separation.</p> <p>Additional resources are required to continue adopting GEIP across these focus areas in Aurora Energy’s business.</p>
Volumes	During the CPP period, Aurora Energy is planning to fill an additional 30.8 FTE roles, and forecasting a decrease of 7 FTEs through staff leaving or being transferred to the business support functions (within people costs), resulting in a net gain of 23.8 FTEs.
Unit rate	N/A

Component	Description
Finding	<p><b>Verified</b> – we consider that the recruitment process, guided by the external reviews that recommended changes to organisational structure to meet the needs for an EDB to operate, is in line with GEIP.</p> <p>Board approval is required for any new appointments – which meant that each role has been closely scrutinised as to its need before being filled. Staff remuneration has been benchmarked against the national median salary for a similar role, with salaries set within a band of 85–115% of the median value for each role. We reviewed and confirmed most salaries fell within this band and the overall average for Aurora Energy is 96% of the median (refer section C.20.5.4).</p> <p>Consequently, it appears that the need is being used to prioritise roles that are required for, with a focus on essential needs. Benchmarking suggests the salaries for these roles are reasonable relative to the NZ market.</p>

Table C.58: CPP preparation step change

Component	Description
Name	CPP preparation costs
Value	CPP period: \$1.4 million Review period: \$1.4 million
Description	Costs associated with preparing 2 <sup>nd</sup> CPP application
Driver	<p>Aurora Energy is proposing a first CPP from RY22 to RY24 and then a further CPP from RY25. Aurora Energy is incurring the costs of preparing an application for the first CPP present.</p> <p>If it prepares for a second CPP, then the costs of doing so will be incurred during the first CPP period.</p>
Volumes	Work activities have been based on actuals for current CPP application, with a review of whether the activity needs to be repeated for the 2 <sup>nd</sup> CPP application, or if the output of the first application can be re-used or updated.
Unit rate	<p>Costs for CPP preparation are split on an equal basis with People portfolio. Aurora Energy has benchmarked the costs for the first CPP application against those incurred by Orion (CPP), Powerco (CPP) and Transpower (IPP), and found that its costs compared favourably against these industry peers.</p> <p>For the 2<sup>nd</sup> application, Aurora Energy expects the costs to be lower as a number of one-off establishment costs have been incurred in preparing the current application. A percentage adjustment based on Aurora Energy's best judgement has been applied to the actual costs for the current application to generate the forecast.</p>

Component	Description
Finding	<b>Verified</b> – we consider it reasonable for Aurora Energy to rely on actual costs for the current application and as basis for forecasting costs for the 2 <sup>nd</sup> application, and acknowledge its consideration in identifying those work tasks that will not require to be redone. We have reviewed the list of activities across Network and Asset Management, Consultation support, Finance and Regulatory and Project Management, and consider the assessment of those tasks that will need to be done, and the percentage allowances on the 1 <sup>st</sup> CPP actual costs for forecasting expenditure for the 2 <sup>nd</sup> CPP as reasonable.

Table C.59: Technology costs step change

Component	Description
Name	Technology costs
Value	CPP period: \$1.0 million Review period: \$1.6 million
Description	Operational technology costs associated with: <ul style="list-style-type: none"> <li>• maintenance and support of the company’s Advanced Distribution Management System (ADMS), also known as SCADA, which is used to operate the Aurora Energy electricity network</li> <li>• maintenance and support of the ADMS IT infrastructure encompassing software licenses, hardware support and third-party services</li> <li>• maintenance and support of the ADMS communications infrastructure encompassing the network connections (including fibre, microwave, radio telephone etc) integral to switching instructions and stable and secure messaging across the Aurora Energy network</li> </ul>
Driver	Operational network needs
Volumes	The level of work has been based on current technology requirements.
Unit rate	Costs have been based on new software support, service level agreements and equipment rentals initiated during RY20.
Finding	<b>Verified</b> – the costs are based on market rates, and the need for the expenditure has been established in supporting operational business activities.

Table C.60: Field audit costs step change

Component	Description
Name	Field audit costs
Value	CPP period: \$0.9 million Review period: \$1.5 million

Component	Description
Description	As part of its ongoing risk-based business assurance programs, Aurora Energy engages independent third parties to undertake field-based audits of the health & safety practises and network compliance standards of contractors operating on its network.
Driver	Compliance
Volumes	Additional 20 audits per annum
Unit rate	Average nominal allowance of \$15 k per audit
Finding	<b>Verified</b> – the increase in the number of field audits is consistent with the additional checks required through the FSA arrangement, and the nominal allowance is considered reasonable based on actual auditing costs during 2019 for Dunedin and Central Otago.

Table C.61: Network evolution step change

Component	Description
Name	Network evolution costs
Value	CPP period: \$2.3 million Review period: \$2.9 million
Description	Network Evolution Plan costs
Driver	Aurora Energy has developed a Network Evolution Plan to enable it to respond to projected increase in distributed energy resources on its network. This covers: <ul style="list-style-type: none"> <li>• uptake of photo-voltaics (PVs) and electric vehicles (EVs)</li> <li>• increasing electrification to support a low-carbon environment</li> <li>• evolving asset management through use of digital technology.</li> </ul>
Volumes	Support work to understand the capacity of local LV distribution networks for increase in penetration of PVs and EVs, technical modelling of distributed energy resources and load growth on the sub-transmission network, and investigating network stability and pricing methodologies based on distributed energy resource equipment.
Unit rate	The forecast has been generated bottom-up using standard external hourly rates for engineers, specialist advisors and analysts, and projection of hours related to the support work initiatives described above.
Finding	<b>Verified</b> – the basis for the estimate of hours appears reasonable, with conservative allowances for external support based on nominal hours for data to be compiled, checked and modelled. The hourly rates for external support appear reasonable, and the need for the project, and timing for this support work, has been well defined in the Network Evolution Plan.

Table C.62: Insurance step change

Component	Description
Name	Insurance costs
Value	CPP period: \$0.5 million Review period: \$1.0 million
Description	Forecast increases in insurance premiums relating to sub-station buildings, plant and equipment (material damages and business interruption), contract works, SONS motor vehicles and a share of the company's general liability policy costs are captured within SONS. Other insurance costs are captured within the premises, plant and insurance portfolio.
Driver	Based on advice from Crombie Lockwood – an insurance broker – provided in January 2020, <sup>227</sup> Aurora Energy considers that insurance premiums for the following cover types will increase over the RY20 to RY24 period, in real terms, and then stay constant: <ul style="list-style-type: none"> <li>• material damages and business interruption</li> <li>• contract works</li> <li>• motor vehicle</li> <li>• liability.</li> </ul>
Volumes	Aurora Energy has assumed that the sums insured across the four cover types will remain constant at levels expected for RY20.
Unit rate	Crombie Lockwood provided ranges of expected premia increases, by cover type on a like for like sums insured basis, as follows over the next 3 to 5 years: <ul style="list-style-type: none"> <li>• material damages and business interruption: 5–10%</li> <li>• contract works: 5–15%</li> <li>• motor vehicle: 5–15%</li> <li>• liability: 10–20%.</li> </ul> From these ranges, Aurora Energy adopted real year on year increases of 10%, 10%, 10%, and 15% over the RY20 to RY24 period.
Finding	<b>Unverified</b> – although it is quite feasible that insurance premia will increase over the CPP and review periods in real terms and the proposed level of cover appears appropriate, it is unclear to us whether the year-on-year premia increases provided by Crombie Lockwood remain accurate. <sup>228</sup>  The Crombie Lockwood report is dated 17 January 2020 and was based on analysis undertaken between 12 December 2019 and 17 January 2020 <sup>229</sup> – which was before when the potential impact of the COVID-19 pandemic was known. Since then, many commentators have highlighted the significant

<sup>227</sup> Crombie Lockwood, *Letter from Pierre Jones to Gary Dixon*, 17 January 2020.

<sup>228</sup> The Crombie Lockwood report made no mention of the COVID-19 pandemic, which is not surprising given that it was provided to Aurora Energy in January 2020.

<sup>229</sup> See: Aurora Energy, *Memo Responding to Insurance Step Changes*, 28 May 2020, p. 1.

Component	Description
	<p>effect that the pandemic will likely have on domestic and global insurance markets.<sup>230, 231</sup></p> <p>For this reason, we are unclear whether the projected real increases in insurance premia satisfy the expenditure objective. As noted below, we recommend that the Commission work with Aurora Energy to better understand what impact the pandemic and economic fallout may have on insurance premia over the CPP and review periods relative to base opex.</p> <p>Moreover, the PPI escalator forecasts provided by Sapere and adopted by Aurora Energy are likely to, at least notionally, reflect projected changes in insurance costs (as insurance is a producer cost).<sup>232</sup> As part of its review of the information, the Commission may want to ensure that there is no double counting of changes in insurance costs over the CPP and review periods.</p>

### C.21.5.3 Key assumptions used

#### Base opex

Aurora Energy has assumed that actual RY19 expenditure for SONS expenditure provides an appropriate base cost for forecasting expenditure over the CPP and review periods. It describes this expenditure as efficient.

Aurora Energy's RY19 expenditure does not appear inefficient to us for the following reasons:

1. Establishing a standalone asset management capability is consistent with GEIP and for the reasons explained by Deloitte outsourcing the SONS function to Delta led to significant challenges for Aurora Energy – and so the *need* for the SONS resources is clear.
2. To establish that capability, costs incurred in RY19 followed a robust process with significant external support and board oversight – given that the step up from prior years was effectively self-funded, it is not unreasonable to assume that Aurora Energy's board and senior management were incentivised to only incur costs for what was needed in the immediate term.

<sup>230</sup> See, for instance: Fitch Ratings, *COVID-19's impact on the global insurance industry*, 21 April 2020, <https://www.insurancebusinessmag.com/nz/news/breaking-news/fitch-ratings-covid19s-impact-on-the-global-insurance-industry-220125.aspx>, which highlights the pressure that insurance companies will be under as a result of the pandemic and the economic fallout.

See also: Insurance Information Institute, *Global Macro and Insurance Outlook*, 4 March 2020, [https://www.iii.org/sites/default/files/docs/pdf/global\\_macro\\_industry\\_outlook\\_q1\\_2020.pdf](https://www.iii.org/sites/default/files/docs/pdf/global_macro_industry_outlook_q1_2020.pdf), which suggests that a decrease in global GDP growth will cause lower insurance premium growth.

See also: Oliver Wyman, *COVID-19 considerations for insurers in Asia*, 9 April 2020, which notes that most lines of business for insurers will face reduce demand for cover. If so, then this may be expected to reduce premia for such cover, at least in the short term.

<sup>231</sup> Although Aon subsequently advised Aurora Energy that it was 'not aware of any suggestion that the pandemic will drive insurance cost reductions moving forward', it recognised that the global situation was still evolving. As noted in footnote 230, other commentaries *have* recognised that this situation could lead to cost reductions, at least in the short term. However, we also recognise that they could increase for various reasons. In the absence of clear analysis and advice, we cannot confirm whether insurance premia will likely increase, decrease, or stay constant in real terms over the CPP and review periods.

See: Aurora Energy, *Memo Responding to Insurance Step Changes*, 28 May 2020, p. 1.

<sup>232</sup> See, for instance, Statistics New Zealand, *Producer price index industry-by-commodity weight tables: 2020*, 17 May 2019, which shows that the historical PPI series for the heavy and civil engineering and professional services (and other) industries include positive weights for insurance costs. Given that Sapere used these historical series to project forward future changes, it is likely that – at least notionally – some future changes in insurance costs are captured in the forecasts.

3. Adjustments to the RY19 base year (decrease of \$1.5 million) for:
  - a. error correction for costs transferred twice from business support for SONS rentals (decrease of \$0.1 million)
  - b. transfer of rental costs for Hillside Road and Terrace Junction to business support (decrease of \$0.1 million)
  - c. removal of payroll costs, one-off type consultancies, recruitment and training costs, and other financial costs (decrease of \$0.8 million)
  - d. cost reduction for stores and logistics through new arrangements from RY20 (decrease of \$0.4 million).
4. Remuneration for the roles that were filled were market tested and guided by external benchmarking – and so it is not unreasonable to assume that the unit costs were efficient.
5. As discussed in the next section, Aurora Energy’s RY19 SONS expenditure is consistent with that of other large New Zealand EBDs and headcount proposed is lower than or otherwise comparable to equivalent Australian EDBs.

### Step changes

A second key assumption is that resourcing levels need to further increase from RY19 to properly establish Aurora Energy’s asset management capability.

For similar reasons as those describe above for the RY19 expenditure, the step up from RY19 to a higher base cost is not unreasonable (refer section C.20.5.2).

### Trend

Aurora Energy has also assumed that growth in the network will increase expenditure by between 1.03% and 1.18% per year over the CPP and review periods. Those growth rates are sourced from the Commission’s DPP for the 2020–25 period.

This assumption does not appear reasonable. Although network growth will likely affect SONS expenditure in the longer term – as a larger network leads to more asset management activities – it is unlikely to affect that expenditure over the CPP and review periods. When establishing the SONS capability and identifying the roles needed, it is highly likely that Aurora Energy factored in the requirements over those periods including from the significant investment planned for the network. It would be a concern if it did not.

### C.21.5.4 Benchmarking

Although subject to limitations,<sup>233</sup> benchmarking can provide useful insight into whether an EDB’s expenditure appears higher, lower or aligned with its peers. Below we consider expenditure, headcount (i.e. volumes), and salaries (i.e. unit rates).

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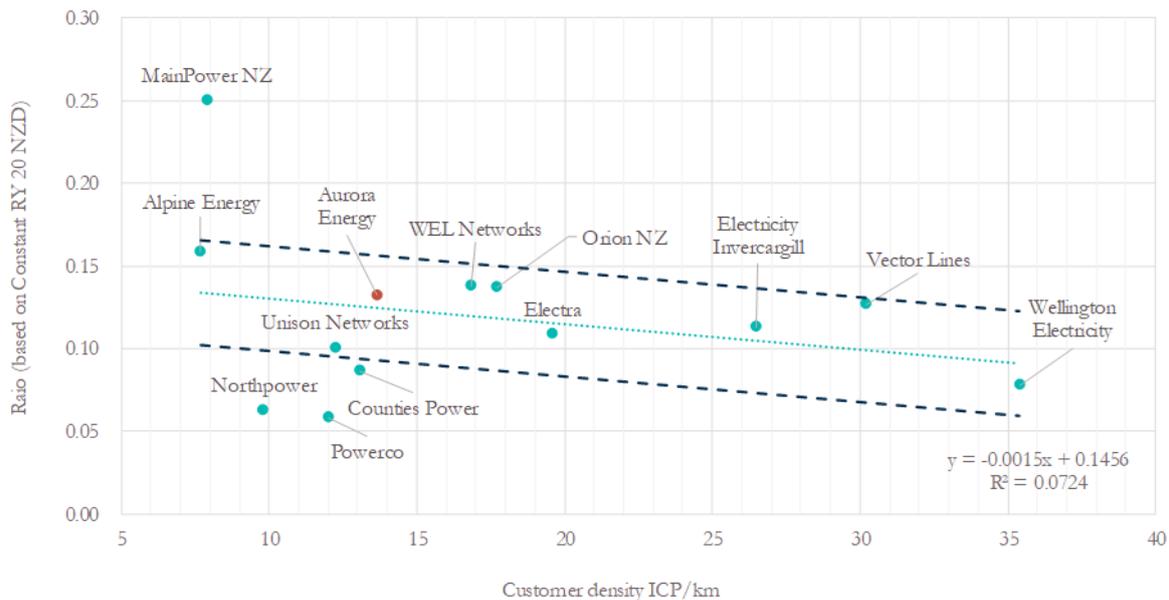
<sup>233</sup> See discussion in section G.1.

**Expenditure**

Figure C.36 compares the SONS costs incurred by Aurora Energy in RY19 with eight comparable EDBs on a cost per total opex and capex basis.<sup>234</sup> Customer density has been used to normalise the results.

From the benchmarking, Aurora Energy is comparable to a range of different sized EDBs – and has an organisational structure in place with costs that are close to average spend per total capital and operational expenditure. This suggests that Aurora Energy has undertaken a robust process to determine its staffing needs.

**Figure C.36: 2019 SONS expenditure per totex ratios vs customer density (\$2020, \$million)**



Source: Commerce Commission published data. Farrierswier and GHD analysis.

**Headcount**

As an alternative benchmark, Aurora Energy’s proposed network headcount (of 95 FTEs) and SONS costs to totex ratio (0.132) is consistent with that of smaller Australian EDBs that have been subject to AER regulation for some time, including:

- TasNetworks – which is the Tasmanian EDB has a ratio 0.109 and 172.15 FTEs
- Evoenergy – the ACT EDB with a ratio 0.169 and 130 FTEs.

Both comparisons suggest that RY19 expenditure and the actual and proposed staffing levels are comparable with that of similar sized and larger EDBs. As such, RY19 expenditure does not appear inefficient.

**Salaries**

Figure C.37 shows the current spread of salaries for SONS and People staff, compared to the national median salary for similar roles. Aurora Energy’s remuneration standard states that base salaries are determined by role size, complexity and the remuneration midpoint applicable to that role.<sup>235</sup> Individual

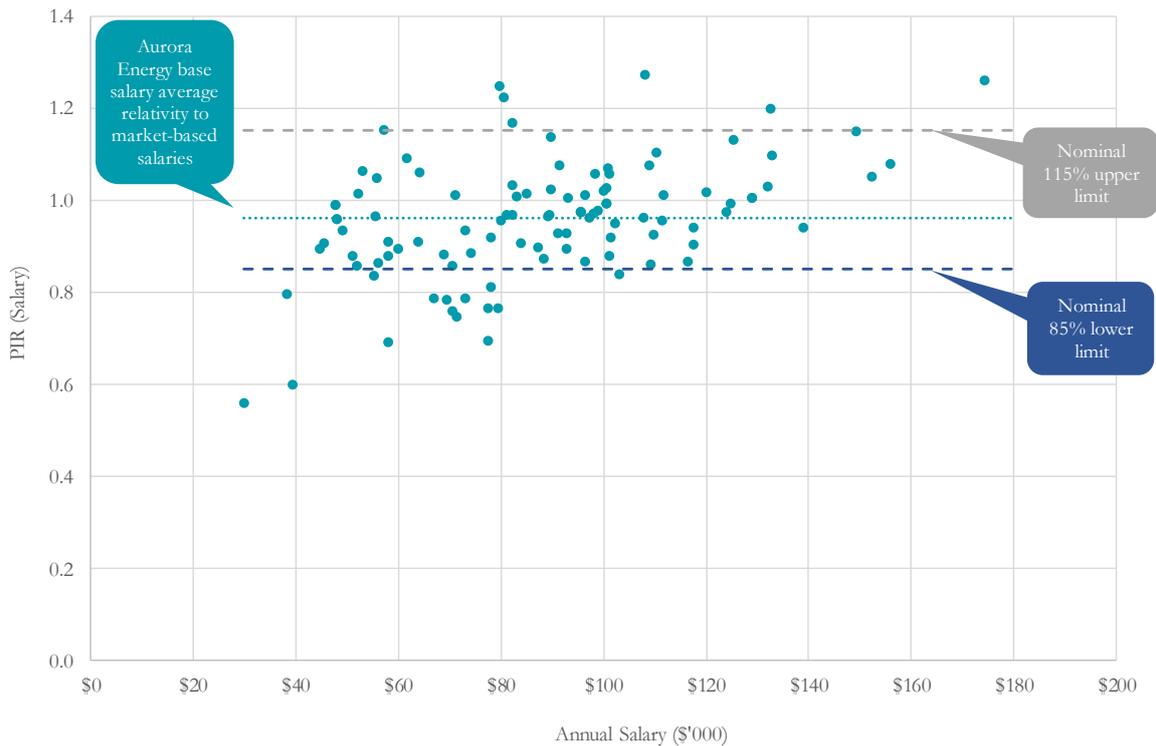
<sup>234</sup> The comparator firms are Alpine Energy, Counties Power, Electra, Electricity Invercargill, Mainpower NZ, Northpower, Orion NZ, Powerco, Unison Networks, Vector Lines, WEL Networks, and Wellington Electricity.

<sup>235</sup> Aurora Energy, AE-SH07-S Remuneration Standard, version 1.0, 31 March 2020

salaries are generally set between 85% and 115% of the market midpoint (median), dependent upon competency and performance.<sup>236</sup>

As shown, overall, the total Aurora Energy remuneration is approximately 96% of market-based remuneration levels. This indicates that the *unit rates* (i.e. the salaries) agreed to by Aurora Energy are reasonable.

Figure C.37: Salaries compared to national median



Source: Strategic Pay 2019 New Zealand data as collated by Aurora Energy. Farrierswier and GHD analysis.

### C.21.5.5 Contingency factors

No contingency factors have been included in the forecast expenditures.

### C.21.5.6 Interaction with other forecast expenditures

Expenditure for SONS does not directly interact with other expenditures, although it is consistent with Aurora Energy’s plans for improved asset management and the associated improvement in network reliability and performance, and the aim of achieving ISO 55000 certification by RY23. However, some of the improvement initiatives forecast for SONS in the CPP period are subject to the implementation of some increased technology expenditure in the ICT strategy.

There is some overlap with people costs in regulation and commercial work, noting that the majority of this expenditure are allocated to Business Support.

Although not modelled, Aurora Energy’s investment in systems, processes and people should lead to some efficiency improvements in the SONS program. It is also not clear exactly what, if any, SONS costs

<sup>236</sup> Ibid., section 2.1, p. 6

are reflected in the proposed capital expenditure forecasts. We intend to engage with Aurora Energy on both points further before finalising our report.

### C.21.6 Deliverability

The forecast expenditure represents a significant step up from historical expenditures. For the most part, Aurora Energy is already either incurring or has committed to incurring the costs of the increase in SONS staff that account. Although it still needs to fill some roles with trained labour, we do not envisage that Aurora Energy will be unable to source the required resources.

One exception to that may be restrictions that result from the COVID-19 pandemic, including on people movements. However, at the time of writing, it was unclear how likely this would be.

Although there is some risk that rapidly establishing a new team as Aurora Energy is doing leads to delivery challenges – especially with all of the other business transformation going on – we have not seen any evidence that suggests this is the case.

### C.21.7 Our finding

In our view, Aurora Energy's base SONS expenditure does not appear unreasonable based on the information reviewed, except for applying a network scale trend and the step change for insurance.

Our view is based on the following observations:

- establishing its own SONS capability is consistent with the Deloitte recommendations and GEIP – such capability helps ensure that Aurora Energy can deliver safe, reliable and affordable electricity to its consumers
- given the significant step up in recruitment required, Aurora Energy's board and senior management appeared to have applied significant top-down challenge to ensure that the new roles are appropriate and meet an immediate need in improvement asset management capability<sup>237</sup>
- Aurora Energy funded the step up in expenditure over RY19 and RY20 without any expected regulatory revenues to cover this – which aligns with the apparent level of challenge applied by the board and senior management
- comparison to other EDBs suggests that RY19 SONS expenditure is not inefficient
- the information provided by Aurora Energy is sufficient to verify the need and forecast costs for the proposed step changes
- although the size of the network may drive SONS expenditure in the future, this is unlikely to be the case over the CPP and review periods where the key driver of that spend is ramping up Aurora Energy's asset management capability to support delivery of significant renewal, maintenance and other programs – which largely factors in network growth already.

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<sup>237</sup> For instance, the information provided indicate that the challenge process led to several positions identified by managers being deferred to a later time and ensured that those that were approved had been closely examined to ensure that they were prudent and efficient.

Removing the scale trend and the insurance step change reduces forecast SONS expenditure from \$49.2 million over the CPP period to \$47.6 million, and from \$80.4 million to \$77.1 million over the review period.

Although there are several limitations with the proposed forecast, we do not consider that these materially affect our view above. These limitations include:

- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments and reliability of reported data
- it is not year clear exactly how capitalised SONS expenditure is factored into the capex forecasts – although forecast capitalised internal labour costs appear consistent with those in RY19 based on the information provided,<sup>238</sup> we could not verify whether that forecast is consistent with the SONS opex forecast
- it is also not clear to us how the global and domestic insurance markets will be affected by the COVID-19 pandemic and what this may mean to insurance premia.

### C.21.8 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast SONS expenditure was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may want to consider:

- whether it is appropriate to:
  - rely on board and management oversight to ensure that the step up in actual SONS expenditure in recent years is prudent and efficient
  - use a base, step and trend approach to forecast SONS given that it is effectively standing up a new team, where historical costs are less relevant
- updating the base year to RY20 – which at the time of writing was not available, but which will be available for the Commission’s determination
- the assumption that SONS expenditure will grow over the CPP and review periods in line with network scale
- what level of staffing is efficient for a network like Aurora Energy’s
- how the COVID-19 pandemic may affect insurance premia over the CPP and review periods and how best to reflect this in the expenditure forecasts<sup>239</sup>
- consistency between capitalised and expensed SONS costs across the entire capital and operating program – which we have not been able to verify

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<sup>238</sup> Aurora Energy advises that its forecast capitalised internal labour is relatively flat over the CPP and review periods and consistent with RY19 actuals. Aurora Energy provided a spreadsheet showing that capitalised internal labour is expected to make up between 2.6% and 3.1% of gross capex over the CPP and review periods, compared with 2.6% in RY19. Similarly, it shows that capitalised internal labour is expected to make up 13.0% of total employee labour costs over the periods, compared with 12.8% in RY19.

See: Aurora Energy, *Capitalised Labour - Summary for IV*, 20 May 2020.

Although we have not audited the accuracy of the data provided or validated whether it aligns with the expenditure forecasts that we have reviewed, the spreadsheet suggests that proposed capitalisation over the CPP and review periods is consistent with actual capitalisation in RY19 – and, therefore, the capitalisation policy applied over that year.

<sup>239</sup> The Commission may want to consider whether the proposed opex escalators already factor in potential increases in insurance costs. Insurance costs, for instance, form part of the Statistics New Zealand’s producer price index measure.

- although outside of our scope, if the Commission does not accept Aurora Energy's proposal for a three-year CPP and subsequent five-year CPP, then the proposed CPP step change may no longer be appropriate.

## C.22 PEOPLE COSTS (O6)

Table C.63: Verification summary – people costs (\$2020, million)

<b>Expenditure category</b>	People costs	
<b>Aurora Energy CPP forecast</b>	CPP period: \$24.7 million Review period: \$40.3 million	
<b>Recommendation</b>	<b>Verified</b> CPP period: \$23.3 million Review period: \$37.7 million	<b>Unverified</b> CPP period: \$1.4 million Review period: \$2.6 million
<b>Expenditure outcome assessment</b>	Benchmarking of people costs in 2019 shows that Aurora Energy is comparable to New Zealand EDB peers of similar size and asset management maturity.  Evidence that Aurora Energy ELT has reviewed and limited growth in FTEs since Jul 2017 to only fill roles required during the CPP and review periods.	Do not consider appropriate to apply network growth rate as growth in number of network assets does not drive increase in people tasks, including any non-network work, at least over the timeframe being considered.  We have not been able to verify the increased training costs per employee.
<b>What needs to be done</b>	Work with Aurora Energy to understand the scope for future efficiency improvements from the significant proposed investment in systems, people and processes.  Assess consistency between capitalised and expensed people costs.	
<b>Potential scope for improvement</b>	Monitor effectiveness of people costs to support the ambitious renewal and other expenditure programs proposed.	

### C.22.1 Project description

This portfolio covers the cost of employing business support staff and external service providers. It also includes costs for the communication staff involved in ongoing customer and stakeholder engagement.

It covers the people costs for the following corporate functions:

- human resources and communications
- accounting, finance and risk assurance
- regulatory and commercial
- information technology (IT).

The cost category excludes expenditure on capital projects, costs and staff directly relating to the management and operation of the network, premise and plant costs, operational technology, and governance and management costs that are not directly related to employment.

### C.22.2 Cost estimate / expenditure forecast

Table C.64 shows the forecast expenditure during the CPP and review periods.

Table C.64: Forecast expenditure – People Costs (\$2020, million)

Item	RY22	RY23	RY24	RY25	RY26	CPP3-year total	Review 5-year total
Expenditure	7.73	8.82	8.11	7.81	7.83	24.66	40.29

### C.22.3 Relevant policies and planning standards

People services are provided in accordance with several internal policies, including those relating to treasury, finance, insurance, recruitment, remuneration, travel, learning and development, and wellness.

These policies themselves based on relevant legislative and regulatory requirements, including:

- statutory reporting requirements
- economic and other regulatory requirements
- employment law
- health and safety law.

### C.22.4 Information provided

Table C.65 presents the information that has been provided by Aurora Energy in relation to the identified program.

Table C.65: Information provided

Title	Reference	Date
POD81 - People	E-36	28 Feb 2020
MOD81 - People Costs Forecast Model	E-81	9 March 2020
P17 - Non Network Opex - SONS and people costs (final) - Post Workshop	V-120	27 March 2020
<b>Provided in response to our draft report</b>		
01 - Memo to Verifier - 21 April 2020	PR-22	23 April 2020
Appendix 1 - Major SONS and People Step Changes and Guide to Supporting Information	PR-23	23 April 2020
Appendix 2, 3, 4 and 5 - SONS People - App 2 to 5	PR-16	23 April 2020
Attachment 2 - Revised PEOPLE BST Forecasting Model	PR-20	23 April 2020
Attachment 3 - Summary of Non-network forecast changes since March 19 workshop	PR-26	23 April 2020
Attachment 4 - IV CPP Cost Forecasts	PR-27	23 April 2020
Attachment 5 - Non-network Opex - SONS and People Workshop Slides	PR-15	23 April 2020
Attachment 6 - Aurora Energy Remuneration Standard	PR-17	23 April 2020

Title	Reference	Date
Attachment 7 - IV Remuneration Benchmarking Analysis - Strategic Pay (SP10) Analysis	PR-18	23 April 2020

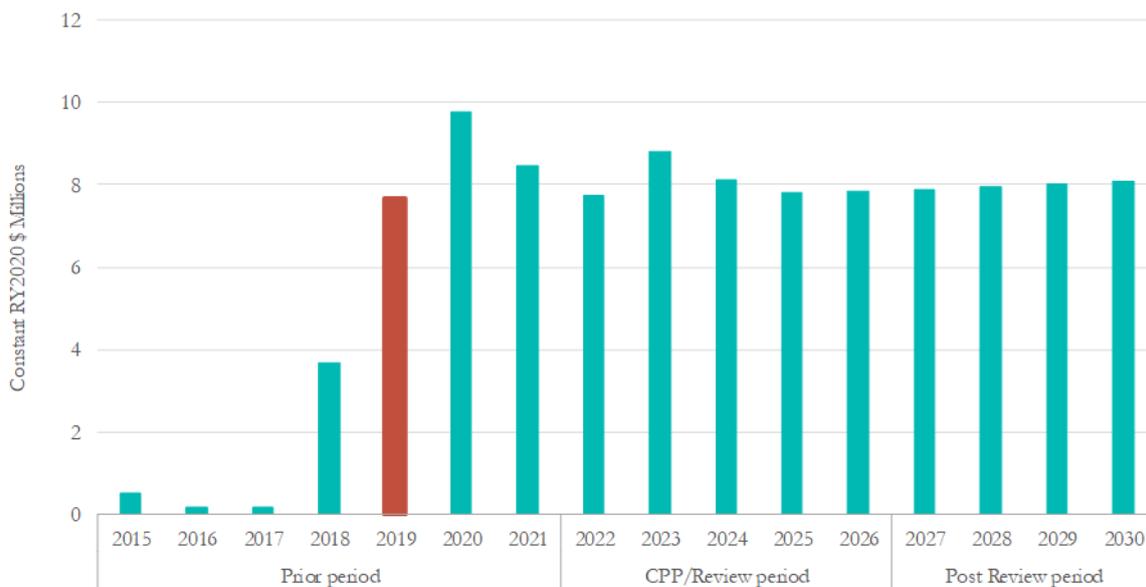
## C.22.5 Assessment of forecast method used

### C.22.5.1 Expenditure trends

Figure C.38 shows the historical and forecast expenditure for the people costs program. Much like the SONS portfolio above, expenditure in RY17 is forecast to increase from \$0.2 million in RY17 to \$9.8 million in RY20, an increase of \$9.6 million, or 60-fold. This step up is not a surprise given that in RY17 Aurora Energy effectively had no People staff.

From RY20 to RY21 people costs reduce by \$1.3 million to \$8.5 million and then remains flat with a slight rise in RY23 to cover the expected costs of a second CPP application for the five years from RY25 (of \$1.4 million over RY23 and RY24). This rise is followed by a gentle reduction through to RY26.

Figure C.38: People Costs – historical and forecast expenditures (\$2020, \$million)



Source: Aurora Energy data. Farrierswier and GHD analysis.

Aurora Energy forecasts its expenditure over the CPP and review periods using the base, step and trend method. Aurora Energy applied this method using RY19 as its base year, making two minor negative accounting adjustment, and adding step changes. It also applies scale escalation.

The increase in expenditure is driven by the recruiting resources to establish and deliver the people costs function. Forecast increases in network scale have a minor impact on the increase.

### C.22.5.2 Expenditure justification

The forecast expenditure represents a significant step up from historical expenditures. The key driver for this was the need for Aurora Energy to establish its own business support capability rather than rely on Delta.

Prior to July 2017, Aurora Energy paid an annual fee to Delta to provide business support services. Aurora Energy effectively had no people costs staff of its own. Following a review by Deloitte – which recommended a new operating structure and governance arrangements for asset management activities – Aurora Energy has identified and sought to fill the roles needed so it could develop and implement new asset management systems and support the expenditure programs over the CPP and review periods.

Based on this recommendation – and a clear business need – Aurora Energy scoped and started filling the roles it considered were needed for it to effectively provide the business support that it needed. Most of the identified roles have now either been filled or committed to, with many of these costs reflected in the RY19 base year expenditure.

Relative to that RY19 expenditure, Aurora Energy proposes a modest \$3.1 million worth of step changes over the CPP period, or \$4.3 million over the review period. Step changes cover:

- recruiting further resources to establish its business support capability along with associated staff training – \$1.7 million over the CPP and \$2.7 million for the review period
- preparing a CPP application over RY23 and RY24 – \$1.4 million over the CPP period
- reduced consultancy costs – a \$1.8 million reduction per year reflecting both one-off consultancy expenditure undertaken in RY19 that is not expected to repeat and lower reliance on external support to deliver business support services as the internal capability is established.

The three main step changes are considered in the following tables. Although we have not reviewed the other step changes in detail (which sum to \$0.07 million for the CPP and \$0.12 million for the review period), we have not identified any concerns with them.

**Table C.66: Staff costs step change**

Component	Description
Name	Staff costs
Value	CPP period: \$0.9 million Review period: \$1.5 million
Description	Resource requirements for ongoing development of the business support functions
Driver	With separation from Delta in July 2017, Aurora Energy required structural reorganisation to manage and operation the distribution network and provide business support previously done by Delta. Additional resources are required to continue establishing GEIP across business support areas.
Volumes	During the CPP period, Aurora Energy is planning to fill an additional 9.2 FTE roles, and forecasting a decrease of 10 FTEs through staff leaving or being transferred to SONS, resulting in a net reduction of 0.8 FTEs. Whilst there is a net reduction, the roles being added as more senior to those that are leaving or transferred, resulting in a net increase in salary costs.
Unit rate	N/A

Component	Description
Finding	<p><b>Verified</b> – we consider that the recruitment process, guided by the external reviews that recommended changes to organisational structure to meet the needs for an EDB to operate, is in line with GEIP.</p> <p>Board approval is required for any new appointments – which meant that each role has been closely scrutinised as to its need before being filled. Staff remuneration has been benchmarked against the national median salary for a similar role, with salaries set within a band of 85–115% of the median value for each role. We reviewed and confirmed most salaries fell within this band and the overall average for Aurora Energy is 96% of the median (refer section C.20.5.4).</p> <p>Consequently, it appears that the need is being used to prioritise roles that are required for, with a focus on essential needs. Benchmarking suggests the salaries for these roles are reasonable relative to the NZ market.</p>

Table C.67: Staff recruitment and training costs step change

Component	Description
Name	Staff recruitment and training
Value	CPP period: \$0.7 million Review period: \$1.2 million
Description	Recruitment and training of business support staff within People portfolio
Driver	Resource requirements Maintaining staff skills and safety requirements
Volumes	Forecast based on staff turnover rate of 13%. Recruitment costs related to staff turnover (\$14 k per annum) Additional staff training and safety investments of \$1500 per employee per year (\$234 k per annum)
Unit rate	N/A
Finding	<p><b>Unverified</b> – the additional staff training costs are driven by an increase in the number of staff (refer SONS) and projected increase in costs per employee from \$1,235 to \$2,735. However, we did not see sufficient supporting evidence for the increase in training costs per employee.</p> <p>As such, although the increase may be justified against the expenditure objective, we have treated this component of the step change (\$0.7 million for the CPP period and \$1.1 million for the review period) as unverified.</p> <p>The estimated staff turnover rate appears reasonable – and is based on a nominal average recruitment and relocation cost allowance of \$12,500 per role. This is comparable with historical costs in RY19, which we have independently benchmarked as being comparable with NZ EDB peers. We have verified the additional recruitment costs as being reasonable.</p>

Table C.68: CPP application step change

Component	Description
Name	CPP preparation costs
Value	CPP period: \$1.4 million Review period: \$1.4 million
Description	Costs associated with preparing 2 <sup>nd</sup> CPP application
Driver	Regulatory requirement for Commerce Commission approval of planned expenditure beyond CPP RY22-24 period
Volumes	Work activities have been based on actuals for current CPP application, with a review of whether the activity needs to be repeated for the 2 <sup>nd</sup> CPP application, or if the output of the first application can be re-used or updated.
Unit rate	Costs for CPP preparation are split on an equal basis with SONS portfolio. Aurora Energy has benchmarked the costs for the first CPP application against those incurred by Orion, Powerco and Transpower, and found their costs compared favourably against these industry peers.  For the 2 <sup>nd</sup> application, Aurora Energy expects the costs to be lower as a number of one-off establishment costs have been incurred in preparing the current application. A percentage adjustment based on Aurora Energy's best judgement has been applied to the actual costs for the current application to generate the forecast.
Finding	<b>Verified</b> – we consider it reasonable for Aurora Energy to rely on actual costs for the current application and as basis for forecasting costs for the 2 <sup>nd</sup> application, and acknowledge its consideration in identifying those work tasks that will not require to be redone. We have reviewed the list of activities across Network and Asset Management, Consultation support, Finance and Regulatory and Project Management, and consider the assessment of those tasks that will need to be done, and the percentage allowances on the 1 <sup>st</sup> CPP actual costs for forecasting expenditure for the 2 <sup>nd</sup> CPP as reasonable.

### C.22.5.3 Key assumptions used

#### Base opex

Aurora Energy has assumed that actual RY19 expenditure for people costs provides an appropriate base cost for forecasting expenditure over the CPP and review periods. It describes this expenditure as efficient.

As with the SONS expenditure described above, Aurora Energy's RY19 people costs does not appear inefficient to us for the following reasons:

1. Establishing a standalone business support capability is consistent with GEIP and for the reasons explained by Deloitte outsourcing the business support function to Delta led to significant challenges for Aurora Energy – and so the *need* for the people costs resources is clear.
2. To establish that capability, costs incurred in RY19 followed a robust process with significant external support and board oversight – given that the step up from prior years was effectively self-

funded, it is not unreasonable to assume that Aurora Energy’s board and senior management were incentivised to only incur costs for what was needed in the immediate term.

3. Adjustments to the RY19 base year for the removal of one-off consultancy costs (decrease of \$1.8 million) offset in part by increases in payroll costs for staff joining part way through RY19 (\$0.9 million) and additional recruitment and training costs for SONS roles (\$0.2 million).
4. Remuneration for the roles that were filled were market tested and guided by external benchmarking – and so it is not unreasonable to assume that the unit costs were efficient.
5. As discussed in the next section, Aurora Energy’s RY19 people costs are consistent with that of other large New Zealand EDBs and headcount proposed is lower than or otherwise comparable to equivalent Australian EDBs.

### Step changes

A second key assumption is that resourcing levels need to further increase from RY19 to properly establish Aurora Energy’s business support capability.

For similar reasons as those describe above for the RY19 expenditure, the step up from RY19 to a higher base cost is not unreasonable, especially given that Aurora Energy has also recognised that this will lead to lower consultancy costs.

### Trend

Aurora Energy has also assumed that growth in the network will increase expenditure by between 1.03% and 1.18% per year over the CPP and review periods. Those growth rates are sourced from the Commission’s DPP for the 2020–25 period.

This assumption does not appear reasonable. Although network growth will likely affect people expenditure in the longer term – as a larger network leads to more business support activities – it is unlikely to affect that expenditure over the CPP and review periods. When establishing the business support capability and identifying the roles needed, it is highly likely that Aurora Energy factored in the requirements over those periods including from the significant investment planned for the network. As noted above for SONS. It would be a concern if it did not.

### C.22.5.4 Benchmarking

Although subject to limitations,<sup>240</sup> benchmarking can provide useful insight into whether an EDB’s expenditure appears higher, lower or aligned with its peers.

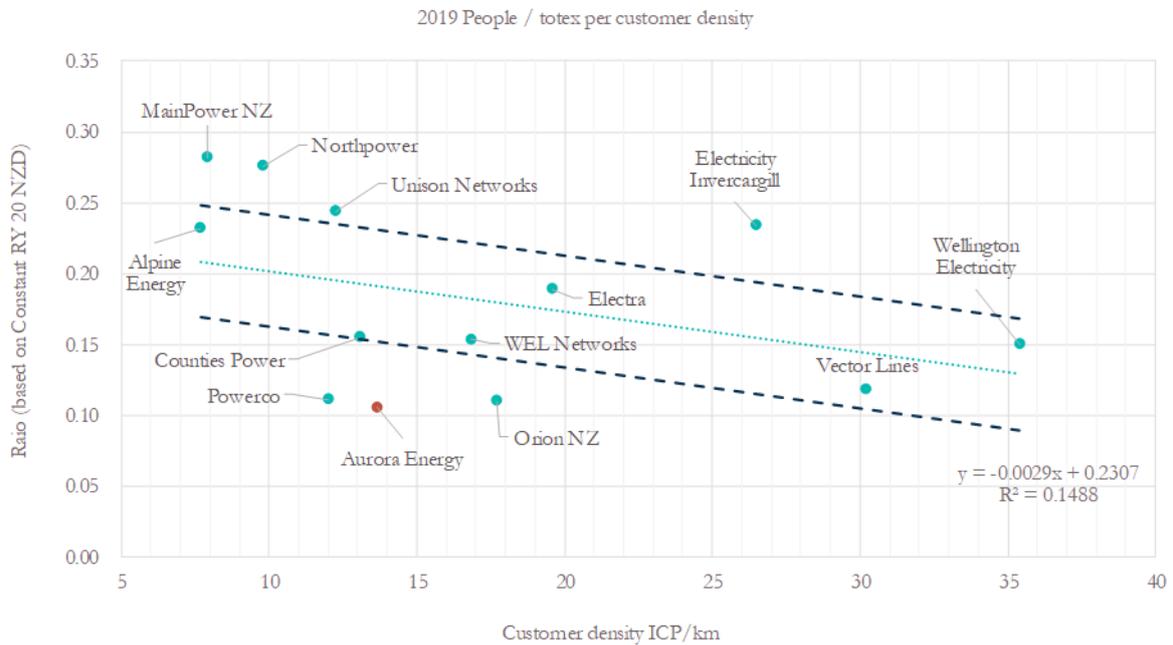
Figure C.39 and Figure C.40 compare the people costs incurred by Aurora Energy in RY19 with nine comparable EDBs on a cost per total opex and capex basis and a cost per total non-network expenditure basis.<sup>241</sup> Customer density has been used to normalise the results.

From the benchmarking, Aurora Energy is comparable to a range of different sized EDBs – and has an organisational structure in place with costs that are below the respective trend lines. This suggests that Aurora Energy’s RY19 expenditure is efficient and has undertaken a robust process to determine its staffing needs. Importantly, the ratios are comparable to larger EDBs with a more mature organisational structure, such as Powerco and Orion.

<sup>240</sup> See discussion in section G.1.

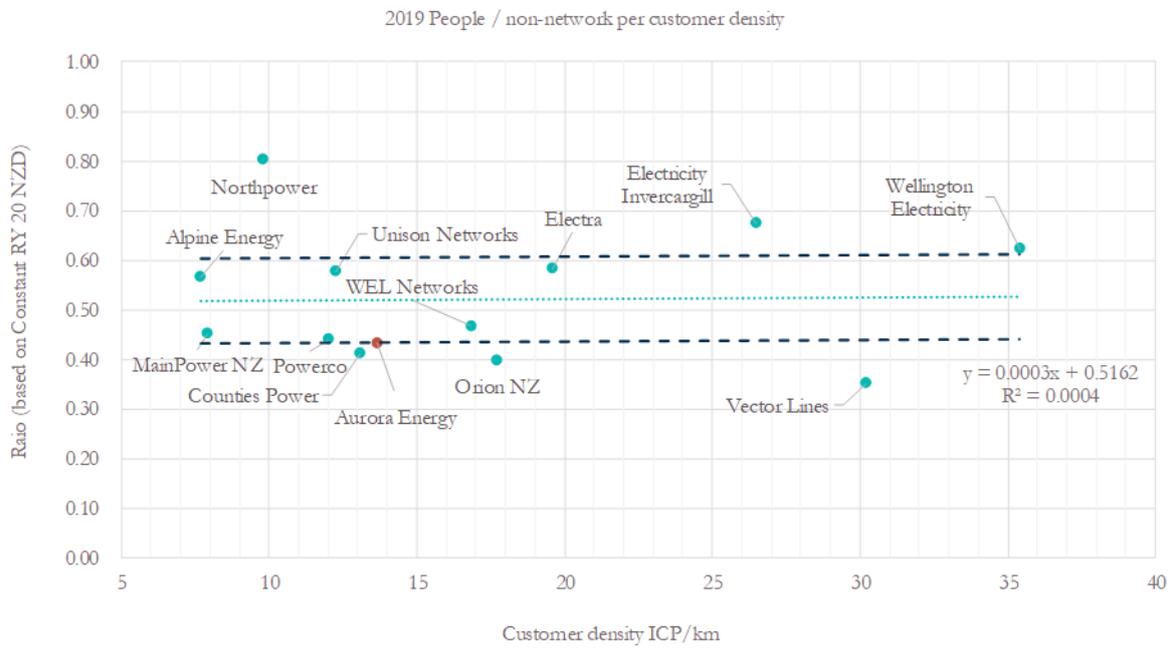
<sup>241</sup> The comparator firms are Alpine Energy, Counties Power, Electra, Electricity Invercargill, Mainpower NZ, Northpower, Orion NZ, Powerco, Unison Networks, Vector Lines, WEL Networks, and Wellington Electricity.

Figure C.39: 2019 People expenditure per totex ratios vs customer density (\$2020, \$million)



Source: Commission published data. Farrierswier and GHD analysis.

Figure C.40: People expenditure per non-network totex vs customer density (\$2020, \$million)



Source: Commission published data. Farrierswier and GHD analysis.

As an alternative benchmark, Aurora Energy’s proposed business support headcount (of 50 FTEs) and people costs to totex ratio (0.106) is consistent with that of smaller Australian EDBs that have been subject to AER regulation for some time, including:

- TasNetworks – which is the Tasmanian EDB has a ratio 0.103 and 164.08 FTEs
- Evoenergy – the ACT EDB with a ratio 0.166 and 106 FTEs.

Both comparisons suggest that RY19 expenditure and the actual and proposed staffing levels are comparable with that of similar sized and larger EDBs. As such, RY19 expenditure does not appear inefficient.

Refer section C.21.5.4 for benchmarking of salaries, which illustrates that the average Aurora Energy role attracts a salary approximately 96% of the national median salary for a similar role.

#### C.22.5.5 Contingency factors

No contingency factors have been included in the forecast expenditures.

#### C.22.5.6 Interaction with other forecast expenditures

There are no obvious direct interactions between the people costs program and other expenditure projects or programs. The program relates covers employment, consultancy, and related costs only for business support work, and is not directly affected by changes in network condition, updated asset management approaches or system operation requirements.

Aurora Energy has applied nominal top-down efficiency improvements to the people costs forecast. This appears to reflect Aurora Energy's proposed investment in systems, processes and people leading to efficiency improvements in the people costs program.<sup>242</sup>

#### C.22.6 Deliverability

As with the SONS program, the forecast people costs represent a significant step up from historical expenditures. For the most part, Aurora Energy is already either incurring or has committed to incurring the costs of the increase in people costs staff that account. Although it still needs to fill some roles with trained labour, we do not envisage that Aurora Energy will be unable to source the required resources.

Although there is some risk that rapidly establishing a new team as Aurora Energy is doing leads to delivery challenges – especially with all of the other business transformation going on – we have not seen any evidence that suggests this is the case.

#### C.22.7 Our finding

In our view, Aurora Energy's base people costs forecast does not appear unreasonable based on the information reviewed, except for applying a network scale trend and the step change increase in staff training costs.

For similar reasons to the SONS program discussed above, our view is based on the following observations:

- establishing its own in-house business support capability is consistent with the Deloitte recommendations and GEIP – such capability helps ensure that Aurora Energy can deliver safe, reliable and affordable electricity to its consumers
- given the significant step up in recruitment required, Aurora Energy's board and senior management appeared to have applied significant top-down challenge to ensure that the new roles are appropriate and meet an immediate need in improvement capability<sup>243</sup>

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<sup>242</sup> In particular, Aurora Energy proposes top-down efficiency adjustments of 0.5% in RY24, increasing to 1.5% in RY26.

<sup>243</sup> For instance, the information provided indicate that the challenge process led to several positions identified by managers being deferred to a later time and ensured that those that were approved had been closely examined to ensure that they were prudent and efficient.

- the reality that Aurora Energy had to fund the step up in expenditure over RY19 and RY20 without any expected regulatory revenues to cover this – which aligns with the apparent level of challenge applied by the board and senior management
- comparison to other EDBs suggests that RY19 people costs is not inefficient
- the information provided is insufficient for us to validate the proposed training costs step change
- although the size of the network may drive people costs indirectly in the future, this is unlikely to be the case over the CPP and review periods where the key driver of that spend is ramping up Aurora Energy’s business support capability to indirectly support delivery of significant renewal, maintenance and other programs – which largely factors in network growth already.

Removing the scale trend and step change for staff training reduces forecast people costs from \$24.7 million over the CPP period to \$23.3 million, and from \$40.3 million to \$37.7 million over the review period.

Although there are several limitations with the proposed forecast, we do not consider that these materially affect our view above. These limitations include:

- benchmarking suffers from challenges such as difficulty comparing EDBs that operate in different environments and reliability of reported data
- it is not yet clear exactly how capitalised people costs are factored into the capex forecasts – although forecast capitalised internal labour costs appear consistent with those in RY19 based on the information provided,<sup>244</sup> we could not verify whether that forecast is consistent with the people costs opex forecast
- it is also not clear exactly how the proposed step changes were calculated or what support there are for them – and therefore, whether they are prudent and efficient.

### C.22.8 Completeness and key issues for the Commission

Most of the information provided by Aurora Energy on forecast people costs was sufficient for us to undertake our verification.

We are not aware of any information that we consider was omitted by Aurora Energy. When undertaking its own assessment of the information, the Commission may want to consider:

- whether it is appropriate to:
  - rely on board and management oversight to ensure that the step up in actual people costs in recent years is prudent and efficient
  - use a base, step and trend approach to forecast people costs given that it is effectively standing up a new team, where historical costs are less relevant
- updating the base year to RY20 – which at the time of writing was not available, but which be available for the Commission’s determination
- the assumption that people costs will grow over the CPP and review periods in line with network scale

<sup>244</sup> Aurora Energy advises that its forecast capitalised internal labour is relatively flat over the CPP and review periods and consistent with RY19 actuals. Aurora Energy provided a spreadsheet showing that capitalised internal labour is expected to make up between 2.6% and 3.1% of gross capex over the CPP and review periods, compared with 2.6% in RY19. Similarly, it shows that capitalised internal labour is expected to make up 13.0% of total employee labour costs over the periods, compared with 12.8% in RY19.

See: Aurora Energy, *Capitalised Labour - Summary for IV*, 20 May 2020.

Although we have not audited the accuracy of the data provided or validated whether it aligns with the expenditure forecasts that we have reviewed, the spreadsheet suggests that proposed capitalisation over the CPP and review periods is consistent with actual capitalisation in RY19 – and, therefore, the capitalisation policy applied over that year.

- whether the proposed step changes are efficient, particularly as the step change in training – which may be justified against the expenditure objective, but we were unable to verify the increase in costs per employee
- whether the modest efficiency improvements proposed for the CPP and review period is reasonable, considering the increased expenditure in business support systems through the ICT capex portfolio
- consistency between capitalised and expensed people costs across the entire capital and operating program – which we have not been able to verify at this point.

Although outside of our scope, if the Commission does not accept Aurora Energy’s proposal for a three-year CPP and subsequent five-year CPP, whether the proposed CPP step change is appropriate.

# Appendix D Asset replacement modelling

## D.1 OVERVIEW

The general approach to review asset renewal models has been an asset strategy planning approach to assess how volumes and expenditure forecasts are developed. This review supports the review of the programs overall in Appendix C and supports the summary of asset replacement models in section 4.6.

Appendix D addresses in detail the verification requirements of Schedule G5(1)(f) of the IM to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast.

The general approach taken to review asset renewal models has been with an asset strategy planning view that then can be translated into volume and expenditure forecasts to inform the review of the programs in Appendix C.

For each renewal program, we have considered:

- **Information** – the information provided by Aurora Energy and other information relied on when reviewing the model
- **Data and integrity** – including what data is available and the quality of that data
- **Asset population and age profile** – including the expected life of assets
- **Asset performance objectives, measures and targets** – this covers reliability, safety, quality and any other output performance objectives, as well as past performance and forecast performance
- **Asset condition and health modelling**
- **Consequence of failure and risk modelling**
- **The asset strategy and renewals model** – including as to the asset strategy, options and data inputs considered, data outputs and replacement forecasts, and validation
- **Our findings.**

### D.1.1 Asset performance

Aurora Energy has not set performance objectives nor targets for its specific asset portfolios, except at a network level. Therefore, there is no direct method of assessing performance measures and targets against service measures, levels and quality standards, or safety objectives.

In the absence of this data, we used benchmarking with comparative organisations and choosing these organisations in each case:

- where sufficient data was available
- where performance measures and targets are in place
- comparability could be made with a similar aging network of the Aurora Energy networks.

We also used RIN data, which is published in Australia, which provides asset performance data on key assets such as poles, overhead conductors, cables and power transformers.

Current and past performance was often difficult to establish; however, in most cases enough information was contained in the WSP report, the relevant PODs, the AMP 2018-2028 and provided in response to RFIs or through discussions with Aurora Energy staff.

This collective information allowed us – in most cases – to form a view as to what level of performance will be achieved with the programs and whether that is reasonable compared to the residual risks accepted by the other organisations based on their performance targets.

### D.1.2 Approach to risk

We did consider the risk assessments conducted by WSP in its infrastructure report for the different asset fleets and we also considered the practices of other organisations and our own industry experience.

The approach considered Aurora Energy’s level of forecast expenditure reliability has interdependencies with:

- targets that are inherent in the modelling to meet asset performance objectives
- the current level of asset performance and the gap to desired targets – improvement expenditure to improve safety to ALARP
- the balance between asset replacement and maintaining levels of target performance – sustaining expenditure to maintain current reliability network performance.

Consideration is made in the review of asset strategies, as to whether the maintenance strategy that affects opex expenditure is reasonable to improve the long-term safety performance of the network and maintain current levels of network reliability. This is an important premise of Aurora Energy’s justification for the CPP proposal.

We have discussed the network asset risk management topic in detail in Appendix F that covers the following topics:

- comparison between WSP and Aurora Energy in undertaking risk assessment of various asset fleets and the corresponding expenditure forecasting approach
- our opinion on Aurora Energy’s strategy to address the network risks identified by WSP in 2018
- comparison of Aurora Energy’s network asset maintenance strategy with known industry information
- Aurora Energy’s operational plan to improve its asset testing, inspection and maintenance regimes for various asset fleets to refine the asset strategies
- demonstration of risk reduction to ALARP for various asset fleets.

## D.2 RENEWAL MODELLING REVIEW

This rest of this appendix provides the outputs from our detailed review of relevant renewal programs that are linked to the program reviews set out in Appendix C. These outputs are presented against a common template and in the order shown in Table D.1.

Table D.1: Reviewed renewal programs

Number	Renewal program
R1	Poles
R2	Crossarms
R3	Distribution conductor
R4	LV conductor
R5	Zone substation

Number	Renewal program
R5.1	Buildings
R5.2	Transformers
R5.3	Indoor switchgear
R5.4	Outdoor switchgear
R6	LV enclosures
R7	Protection

The following provides links to benchmarking reference documents in the public domain:

Document	Author	Date	Link
2018 Asset Management Plan	Top Energy	27 March 2018	<a href="http://topenergy.co.nz/wp-content/uploads/2018/03/2018-Asset-Management-Plan-final-reduced.pdf">http://topenergy.co.nz/wp-content/uploads/2018/03/2018-Asset-Management-Plan-final-reduced.pdf</a>
2018 Asset Management Plan	WEL Networks	29 March 2018	<a href="https://www.welectricity.co.nz/disclosures/asset-management-plan/2009-2018-asset-management-plans/">https://www.welectricity.co.nz/disclosures/asset-management-plan/2009-2018-asset-management-plans/</a>
Electricity Asset Management Plan 2019	Powerco	2019	<a href="https://www.powerco.co.nz/media/2064/2019-electricity-amp-powerco-vf.pdf">https://www.powerco.co.nz/media/2064/2019-electricity-amp-powerco-vf.pdf</a>
State of the infrastructure report 2017/18	Western Power	25 September 2018	<a href="https://westernpower.com.au/about/reports-publications/state-of-the-infrastructure-report-201718/">https://westernpower.com.au/about/reports-publications/state-of-the-infrastructure-report-201718/</a>
Access Arrangement Information for the AA4 period	Western Power	29 November 2012	<a href="https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/western-power-access-arrangement-period-2012-2017/decisions-and-proposals">https://www.erawa.com.au/electricity/electricity-access/western-power-network/western-powers-network-access-arrangements/western-power-access-arrangement-period-2012-2017/decisions-and-proposals</a>
Powerline Asset Management Plan	SA Power Networks	January 2019	<a href="https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal">https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal</a>
Independent Verification Report – Transpower’s RCP3 Expenditure Proposal (2020-25)	Synergies and GHD	12 October 2018	<a href="https://www.synergies.com.au/reports/independent-verification-report-transpowers-rcp3-expenditure-proposal-2020-25/">https://www.synergies.com.au/reports/independent-verification-report-transpowers-rcp3-expenditure-proposal-2020-25/</a>

## D.3 POLES RENEWALS (R1)

### D.3.1 Information provided

Table D.2 presents the information that has been provided by Aurora Energy in relation to the identified renewal program models.

Table D.2: Pole renewals information provided

Title	Reference	Date
01 - Pole Survivor Curve Model	IP2-97	31 January 2020
MOD01 - Poles Renewals Forecast	E-27	28 February 2020
POD01 – Poles	E-28	28 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-12467	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FA01-F01 - Compromised Pole Site Assessment	IPC-1075	29 November 2019
AE-FA01-F03 - Design - Structural Pole Assessment	IPC-1073	29 November 2019
AE-FR03-F02 - Pole-Line Installation Form	IPC-1039	29 November 2019
AE-ND01-T01 - Pole Design	IPC-1012	22 November 2019
<b>Provided in response to our draft report</b>		
200516 Pole Reinforcement note	PR-72	18 May 2020

### D.3.2 Other information relied on

Table D.3 sets out the other information that we relied on when reviewing Aurora Energy's pole replacement expenditure.

Table D.3: Other information relied on

Title	Author	Date
Regulatory Information Notices (RINs) submitted by the Australian electricity distribution businesses <sup>245</sup>	Various Australian EDBs	Various dates
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017
Powerline Asset Management Plan	SA Power Networks	January 2019
Independent Review of Electricity Networks	WSP	21 November 2018
2019 and 2020 Asset Management Plans	Powerco	March 2019, March 2020
2020-2030 Asset Management Plan	The Power Company	March 2020
2020-2030 Asset Management Plan	Unison Network	March 2020
Electricity distributors' information disclosure data 2013-2019.xlsm	The Commerce Commission	05 November 2019

### D.3.3 Data and integrity

#### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report. The key sources are:

- **asset attributes** – includes GIS, structured lines, Xivic and older records
- **asset condition and performance** – includes Deuar testing system, outage data and public hazard database.

#### Data quality

Overall, the asset attribute data for this fleet was good and mostly complete. Minor data gaps were mainly noted around pole location, material types, in service status and installation dates. Major data gaps were mainly noted around pole strength, foundation type and pole usage/arrangement type.

Aurora Energy has adopted probabilistic model that uses historical replacement data to develop asset specific survivor curve for wood pole fleet, and adopted age based model that uses asset attribute data for steel/concrete pole fleet to forecast replacement volumes. Not all available asset data is utilised in this modelling approach. The integrity of the relevant asset attribute and past performance data was sufficient to undertake statistical asset failure analysis and provide accurate forecasting in the replacement expenditure modelling.

<sup>245</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

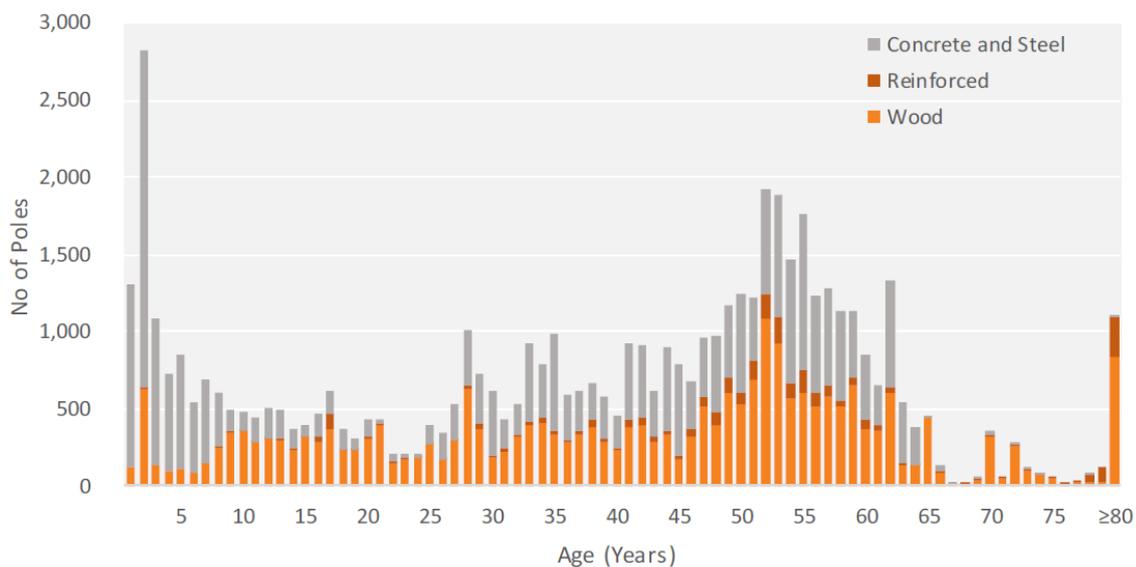
### D.3.4 Asset population and age profile

#### Asset population by age

Aurora Energy has indicated that it owns 54,068 poles as of February 2020 in the POD01, excluding consumer poles. It consists of 27,795 wood poles – out of which 2,758 are reinforced – and 26,273 concrete and steel poles.

The WSP report notes that where pole installation dates were not known, the data had been inferred based on assumption, including the age of associated plant. We believe this is a reasonable approach to fill in the data gaps for this fleet. Figure D.1 shows the poles age profile.

Figure D.1: Poles age profile



Source: Aurora Energy, POD01 – Portfolio Overview Document | Poles

#### Expected life – wooden poles

Aurora Energy has performed a Weibull survivorship analysis based on historical asset failure data and the age of the asset when it was replaced. The Weibull distribution parameters are then used to calculate the failure rate of the wood poles given its age.<sup>246</sup>

#### Expected life – steel poles

Aurora Energy has assumed the expected life for concrete and steel poles to be 75 years. Aurora Energy expects its fleet of concrete and steel poles to be in good condition, despite the lack of historical inspections, as not many have exceeded their expected lives as shown in Figure E.1. Accordingly, it has not performed similar asset failure analysis to determine the median age of concrete and steel poles failure in its pole survivor curve model.

The 75 years old assumption is more than the median expected life of concrete and steel poles compared to that determined by the AER. However, based on our experience in the Australian and New Zealand industries, we believe that the assumed expected life of 75 years for concrete and steel poles is not

<sup>246</sup> Median age of the wood pole failure including infant mortality and old age cutoff is 50 years and is based on failure events of 7,636 wood poles. See: Aurora Energy's '01 – Pole Survivor Curve Model' spreadsheet.

unreasonable with the exception of high corrosive environments where the expected life is shorter, as summarised in Table D.4.

**Table D.4: Life expectancy by pole type**

Pole type	Life expectancy
Hardwood (untreated)	50 years
Hardwood (treated)	50 years
Concrete (old type)	70 years
Concrete (octagonal)	80 years
Steel (averaged across corrosion zones)	50 years

Source: GHD knowledge based on review of SA Power Networks, Western Power and Transpower asset data.

### D.3.5 Asset performance objectives, measures and targets

#### Reliability, safety, quality and any other output performance objectives

Aurora Energy has advised that it does not have any performance objective or targets set for poles in terms of asset failures, supply reliability, safety outcomes, supply quality etc.

The POD01 describes the lack of accurate historical records that can be confidently used to establish asset performance measurements and objectives (such as unassisted pole failure rate, or supply impact attributed directly to lack of pole performance, or fire start count, or safety incident count etc.). Aurora Energy plans to collect accurate information to build such measurements in the future which can then be utilised to drive asset management improvements.

#### Past performance and forecast performance

Aurora Energy’s AMP 2018-28 (pages 104–105) indicates that it lacks historical data on pole failure and how it has impacted SAIFI, noting that approximately 10% of the unplanned SAIFI is attributable to overhead structures which also includes cross arms and insulator failures. Absent an established performance measurement, as an interim measure, Aurora Energy is using historical SAIFI performance as a proxy for the total number of pole failures.

POD01 shows five-year average SAIFI over the last two five-year periods which show deteriorating reliability performance (Figure 4, Page 7, POD01) due to pole failures. Aurora Energy has indicated in its asset management plan that there were 11 pole failures since July 2019, with seven failures related to third parties (and something else) leaving four unassisted pole failures.<sup>247</sup> We calculate that this translates to 4-5 pole failures per 10,000 poles. By comparison, the AER’s recent published Australian pole performance information (i.e. RIN data) shows that the average wood pole failure range to be 0.5 to 3.0 per 10,000 poles/year with most EDBs performing at less than 1. We note that the Australian data is not a perfect replacement for actual data relevant to Aurora Energy’s network, but it is not unreasonable for the purposes of informing our review.

<sup>247</sup> Poles and crossarms renewal workshop presentation held on 17 March 2020, P06 – Renewals – Poles and Crossarms.pptx provided on 25 March 2020.

The unassisted pole failure rate is a measure of the accepted residual safety risk to workers and the public directly attributable to wood pole failures. The inspection and renewal program then needs to be efficient in achieving this performance level.

### **D.3.6 Asset condition and modelling**

#### **Asset health / condition and asset subpopulations**

Aurora Energy has applied an asset health index (AHI) methodology for wood poles that differ from other asset classes. The AHI determined for the wood poles fleet is based on the expected remaining life using the wood pole survivor curve. Using this analysis, percentages of the total fleet of poles is then assigned an H1 to H5 health score which then categorises them for future replacement based on remaining life.

Aurora Energy has used a survivor curve model that is based on historical rates for the number of poles in the fleet that would be expected to have insufficient remaining strength from pole testing. Aurora Energy has considered the remaining age of its steel/concrete pole fleet to denote the AHI based on the fleet age profile and the assumed expected asset life.

Poles are not currently further segmented than the designation of wood, concrete or steel type. This could be used in the future to have different expected lives for poles and improve the accuracy of forecasts.

### **D.3.7 Consequence of failure and risk modelling**

#### **Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure**

Public safety is a key driver identified by Aurora Energy in its POD01 and throughout its CPP proposal supporting material, and has been used to prioritise individually identified pole for replacement at the delivery stage.

Pole location in high public traffic areas determines the criticality rating assigned to poles, with such a rating driven by safety considerations only. Other consequences such as lost load, customers impacted, planning by outage zone, network configuration etc. are not presently considered by Aurora Energy as far as we could tell. Aurora Energy plans to develop a criticality model for poles during the CPP period. This is a reasonable risk-based approach to achieving a stronger focus on safety.

#### **Risk assessment methodology**

The asset health assessment used by Aurora Energy does not specifically consider failure consequences (i.e. criticality) to determine risk and to refine the asset strategy, and inspection and condition invention strategy. However, due to the five yearly inspection interval there is little change to the renewals quantities (the pole is either replaced before failure or the pole fails beforehand).

Segmenting the inspection cycles and testing methods could optimise opex and still achieve an accepted risk profile (considering high to low public safety zones). Aurora Energy will be using the criticality of a pole failure during the CPP and review periods to inform the replacement response priority.

### D.3.8 Asset strategy and renewals model

#### Asset strategy

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish its 2018-28 AMP. POD01 can be viewed as the asset management plan for this fleet, or at least an overview of it. The renewal model for pole is one of the more robust models developed by Aurora Energy that uses historical asset failure and replacement records.

The maintenance approach includes:

- routine pole inspection
- condition assessment – including visual, Deuar mechanical testing for wood poles, and dig probe and hammer testing for steel and concrete poles
- defect management
- fault repairs to retain asset in service until it is no longer safe or economical to do so.

The frequency of the inspection and condition assessment routine is not unreasonable at five yearly period for both activities. This frequency aims to detect a pole having inadequate remaining strength prior to failure.

Aurora Energy uses a volumetric approach – i.e. forecast quantities  $\times$  unit rate – to calculate the expenditure forecast. Asset health based on pole survivor curve analysis for wood poles and remaining age for steel and concrete poles is used to forecast expected quantities.

While the above asset approach is consistent with industry practice for such asset fleet, the volumetric forecasting approach results in a risk averse forecast.

#### Opportunity for reinforcement

After submitting our draft report, we further queried the wood pole replacement vs. reinforcement strategy adopted by Aurora Energy and the corresponding reinforcement proportion (0%) variable input assumed in the pole renewal forecast model MOD01.

We considered the AMPs published by various NZ EDBs and compared the pole asset strategies to that proposed by Aurora Energy for the CPP and review periods. Four of those EDBs – namely, Aurora Energy, the Power Company, Unison Networks and Powerco – reinforce some proportion of their wood pole fleets to extend their expected asset life by 15–20 years for capital investment deferral purpose.

Our observations are set out in Table D.5. We also discussed pole reinforcement in New Zealand with a service provider that operates across both the Australian and New Zealand markets to better understand the uptake of this asset management strategy in NZ. Our discussion aligned with the observation gained from the review of the EDB AMPs set out below.

Table D.5: Selective survey of NZ EDB pole reinforcement practices

EDB	Observations
Aurora Energy	<ul style="list-style-type: none"> <li>• Wood poles were / are being reinforced to balance the FTPP. As of 1 April 2019, Aurora Energy had 2,758 reinforced wood poles across its network. With passage of time since then we assume that presently there are approximately 4,000 reinforced wood poles. Most of these reinforced wood poles are in the Central region.</li> <li>• Analysis of the backlog of wood pole replacement and reinforcement quantities expected / modelled to occur in 2020 indicates that Aurora Energy has been delivering / planning for approximately 40% reinforcement vs. replacement ratio during the FTPP in recent times.</li> <li>• Aurora Energy is not planning for further reinforcement activity during the CPP and review periods as per POD01. Continuing to reinforce some portion of the wood poles in the CPP and review periods would contribute to lowering consumer price increases; however, Aurora Energy has cited several factors that in its view do not support the practice in the longer term compared with the risk mitigation strategy adopted during the FTPP program.</li> </ul>
The Power Company	<ul style="list-style-type: none"> <li>• The Power Company has a population of 19,254 wood poles compared to Aurora Energy's 28,972.<sup>248</sup> The AHI profile of wood pole fleet of both The Power Company and Aurora Energy are very similar. Approximately a quarter of the wood pole fleet are categorised as H1 or H2 in both EDBs.</li> <li>• Both categories of wood poles are driving their respective pole renewal forecasts. The concrete/steel pole fleets are young and healthy in both EDBs and do not materially contribute to their respective pole renewal forecasts. Both utilities are neighbouring EDBs.</li> <li>• Given this context, The Power Company has been reinforcing some of its H1 and H2 categorised MV and LV wood poles. Its latest AMP forecasts a standalone annual budget of \$254,000 for the next 10 years for this life extension activity. This corresponds to 161 (estimated) wood pole reinforcements per annum for a fleet population of 19,254 wood poles (i.e. per annum wood pole reinforcement rate of 0.8%). The per annum wood pole replacement information (just by itself) is not publicly available for The Power Company.</li> </ul>

<sup>248</sup> The latest reporting available in the EDBs information disclosure data 2013–2019, sourced from the Commission website.

EDB	Observations
Unison Networks	<ul style="list-style-type: none"> <li>• Similar to Aurora Energy, Unison Networks’ concrete and steel pole fleets are young and healthy. As such the condition of these pole fleets do not materially contribute to the respective pole renewal forecast for both EDBs.</li> <li>• Unison Networks has a population of 27,165 wood poles compared to Aurora Energy’s 28,972.<sup>249</sup> The AHI profile of Unison Networks’ wood pole fleet is healthy and as such its pole renewal forecast is not significant compared to its other renewal programs. The pole renewal expenditure is also subdued because Unison Networks reinforces some of its wood poles. Unison Networks has been reinforcing poles for many years and plan to do continue in the future. Unison Networks forecasts its pole renewals of \$4.6 million per year over the next few years, dropping to \$3.6 million from RY26 onwards. This is made up of mostly wood pole replacements with a portion of reinforcements.</li> <li>• The wood pole fleet population is very similar between Unison Networks and Aurora Energy. The age profile is also very similar for this fleet between the two EDBs. For example, the bulk of the wood poles were installed prior to 1985 and concentrated during the 1960/70s in both EDBs. However, and contrastingly, the AHI profile of Unison Networks is much healthier than Aurora Energy’s for this fleet – and accordingly the pole renewal forecast is subdued too.</li> </ul>
Powerco	<ul style="list-style-type: none"> <li>• Powerco has a population of 33,406 wood poles compared to Aurora Energy’s 28,972.<sup>250</sup> The AHI profile of the wood pole fleets of both Powerco and Aurora Energy are very similar. Approximately a quarter of the wood pole fleets are categorised as H1 or H2 in both EDBs. Both categories of wood poles are driving its respective pole renewal forecasts. Like Aurora Energy, Powerco’s concrete and steel pole fleets are young and healthy and do not materially contribute to its pole renewal forecast.</li> <li>• Powerco’s latest AMP states that it is undertaking – or has now undertaken – a trial of wood pole reinforcement in RY20, and if successful it will incorporate this method of wood pole life extension into its pole fleet management plan in the future. This life extension technique is being considered for poles installed on remote networks where the costs and complexity of renewal with concrete poles is out of proportion with the projected economic value of the remote feeder.</li> </ul>

After raising these observations, Aurora Energy explained that:

- its recent and present practice of wood pole reinforcement was due to the urgency needed to:
  - arrest the increasing wood pole failure risk
  - manage the workload of the FTTP
- this urgency will not last beyond 2020 and the find rate of the wood pole for reinforcement will be less.

Aurora Energy expects that by the end of 2020 it will have reinforced all the wood poles possible in its fleet where remediation at the ground level was required for the time being, with no scope for additional wood poles reinforcements thereafter. Aurora Energy considers that its recent and reactive wood pole reinforcement activity should not be extrapolated in the forecast for the CPP and review period.

<sup>249</sup> The latest reporting available in the EDBs information disclosure data 2013–2019, sourced from the Commission website.

<sup>250</sup> The latest reporting available in the EDBs information disclosure data 2013–2019, sourced from the Commission website.

Aurora Energy also further explained why it is proposing not to reinforce poles over the CPP and review periods. Its reasons are set out in Table D.6, along with our observations.

**Table D.6: Aurora Energy’s clarification for not considering wood pole reinforcement forecast**

Explanation	Our observations
<p>Aurora Energy presently does not foresee the capability to provide a sufficient pipeline of wood poles for reinforcement to provide a contractor with advance visibility for such work in the future.</p> <p>The recent wood pole reinforcement experience was a reactive and urgent action to arrest the increasing asset failure risk and to buy more time.</p>	<p>Presently Aurora Energy’s asset strategy for wood poles may not be sufficiently embedded, including as to:</p> <ul style="list-style-type: none"> <li>• the inspection and testing techniques</li> <li>• pole data (including ground conditions and foundation design)</li> <li>• risk assessments and option to inform ongoing reinforcement strategy – and hence renewal forecast to incorporate reinforcement activities.</li> </ul> <p>However, based on the opportunity to use the asset condition data from the FTPP, we expect Aurora Energy could conduct an independent engineering review within the CPP period – incorporating industry based experience and research – as to whether a reinforcement program is justified and should be re-established. An independent expert report to assess and address the community concerns around the safety of the reinforcement solution could supplement the engineering review. Such review can establish criteria for reinforcement solution (for e.g. site access by EWP), operational risk assessment of pole top loading while working and standard for temporary stay structure.</p>

Explanation	Our observations
<p>Aurora Energy’s network area has high ground water table levels making the load bearing capacity of the soil weak in some of the Central Otago region and the Dunedin region.</p> <p>Also, the stub of the wood poles in the Dunedin region are encased in concrete blocks or foundation in the ground per the legacy network design standard. Therefore, the opportunity to reinforce wood poles is not practical in the Dunedin region.</p> <p>Further, the level of pole top defects (including crossarms) is expected to be high and the combined cost of reinforcement and ‘defect remediation’ hampers the economic argument for reinforcement, especially in light of reduce reinforcement work volumes and reconductoring projects.</p>	<p>We have noted the geotech condition of the Central Otago and Dunedin regions.<sup>251</sup> There will be instances where poles are not suitable for reinforcement. Poles with concrete around the pole butt would be unsuitable for reinforcement and would be in addition to poles with inadequate pole top remaining life.</p> <p>Similarly, wood poles with pole top structure condition issues or defects would be unsuitable. We are not suggesting to reinforce such wood poles.</p> <p>Due to the geotech condition, legacy foundation design, and the poor state of crossarms and pole tops, the volume of wood poles suitable for reinforcement will be less than for other EDBs. We also expect that going forward the volume of wood pole suitable for reinforcement will be less than the recent volume during the FTTP.</p>
<p>Reinforcement of wood pole address the issue of timber rot or decay and the loss of timber strength at the ground level. Reinforcement solution requires the stub – i.e. the underground butt section – and the above ground portion of the wood pole to have enough timber strength for the solution to work as it ‘bridges’ or reinforces the timber at the ground level.</p> <p>While most of the critical wood pole deterioration experienced by Aurora Energy is just below groundline, there has been examples of deeper underground stub decay issues. This is further compounded by the weak soil bearing capacity issue (as described above). This can sometimes be evidenced by poles leaning; indicating the poor soil load bearing capacity.</p>	<p>Our understanding is that the pole reinforcement method and associated installation is certified to meet AS/NZS 7000 requirements, regardless of the pole butt condition provided the soil has specified load bearing capacity. Tests have been successfully conducted in the United States and Australia on these systems.</p> <p>Aurora Energy may need to confirm the performance of the system with little or no underground pole butt to address community safety concerns. The Deuar testing method can conduct tests that include and confirm ground bearing strength.</p>
<p>The supplier claim regarding bending strength focuses only on their product (sleeves, trusses, brackets, nails etc.) to meet the AS/NZS 7000 standard. Such a claim does not consider the soil condition and its load bearing capacity in which the products are inserted to support the deteriorating wood poles.</p>	<p>Aurora Energy may need to confirm the performance of the system in high water table areas to address community safety concerns. The Deuar testing method can conduct tests that include and confirm ground bearing strength.</p>

<sup>251</sup> This explanation is corroborated by the summary findings documented in the South Dunedin Coastal Aquifer & Effect of Seal Level Fluctuations, October 2012, Otago Regional Council.

Explanation	Our observations
<p>The identified ‘red tag’ condition defects in wood pole need to be corrected within 90 days according to the Electricity (Safety) Regulation 2010. While this regulation provides some flexibility to this requirement depending on safety risk and property damage consideration, Aurora Energy is proposing to replace <i>all</i> ‘red tagged’ wood poles regardless of the criticality during the CPP period.</p> <p>Given this 90-day period to correct the ‘red tagged’ wood poles, Aurora Energy will not have a commercially viable volume of reinforcement work to outsource to its contractors in each 90-day batch.</p>	<p>The usual industry practice indicates deteriorating wood poles to be replaced when it reaches the minimum safety factor of two to the design load.</p> <p>If pole testing is conducted on a feeder basis, then an option is to select poles for reinforcement over a range of safety factors above two to provide a forward pipeline of reinforcement work while reasonably (risk assessed) meeting the 90-day compliance.</p> <p>Before adopting such an approach, its economic viability would need to be considered, including by considering other defects occurring on the pole. If adopted, the reinforcement solution is ideally suited for wood poles with a defined range of assessed remaining timber strength at the ground level.<sup>252</sup> Such a condition can correspond to assets with some remaining asset life (for e.g. H3 category of AHI), instead of only end of life condition (e.g. H1 category).</p> <p>We expect Aurora Energy would refine its pole inspection procedure to include a modified operational decision flowchart and criteria for pole renewal or reinforcement actions. This could be used to inform economic viability of reinforcement.</p>
<p>Many poles that would be reinforced would soon be replaced under reconductoring projects and therefore reduce the number of reinforcement candidates, making a reinforcement program less viable from a volume perspective.</p>	<p>During the CPP period some wood poles that are candidates for reinforcement will likely be replaced through the reconductoring projects – reducing the potential for reinforcement.</p> <p>However, we expect that from RY25 onwards Aurora Energy will have sufficient capability (asset information, system, people and strategy) to identify, plan and coordinate this activity alongside other capex programs.</p> <p>Going forward, we also expect that:</p> <ul style="list-style-type: none"> <li>• Aurora Energy could identify potential candidates for wood pole reinforcement within other capex programs, and</li> <li>• the volume of wood poles suitable for reinforcement will be less than the recent volume during the FTPP.</li> </ul>

Soil condition and the prevalence of the wood pole decay below the ground present challenges. At the same time, Aurora Energy is still considering both wood pole science and the trade-off between short term reinforcement activity and longer term economic benefits – and hence it is currently unable to identify wood poles for reinforcement well in advance for delivery efficiency.

<sup>252</sup> Ordinarily an EDB will have this predefined in its wood pole asset strategy.

For this renewal program we are satisfied that Aurora Energy has assessed the replacement vs. reinforcement options to address the need and the justification provided for opting with replacement strategy for the CPP period. However, by the end of the CPP period Aurora Energy should have overcome the present limitation of its asset management system and refined its asset strategy as commented in Table D.6. This should allow Aurora Energy to incorporate wood pole reinforcement activity, even if it is limited or the find rate will be less due to the described soil condition and prevalence of pole top defects and wood pole decay characteristic below the ground.

For these reasons, in our view, it is feasible for Aurora Energy to reinforce approximately 20% of its wood poles proportion – instead of outright replacement – to restrain and defer some pole renewal investment from RY25 onwards during the review period. Modelling this proportion in the pole renewal forecast model MOD01 yields the per annum wood pole reinforcement rate of 0.6%, which is less than the neighbouring The Power Company annual rate. This proportion is less than the reinforcement proportion of 40% delivered or planned by Aurora Energy during the recent FTFPP. This proportion is also lower than the reinforcement proportion ranging from 21% to 57% in recent years among the Australian EDBs where this is a common asset management practice.<sup>253</sup> Our 20% estimate for Aurora Energy represents a lower range of this asset management practice in the industry – and we believe is a level possible to achieve from RY25 onwards based on expert assessment and careful planning.

### Options and data inputs

Aurora Energy has made the following assumptions:

- the survivor curve is based on historical wood pole failure records – this is a not an unreasonable proxy for future wood pole replacement requirement
- the expected life of concrete and steel pole is assumed to be 75 years – this is not unreasonable and together with the age profile of this asset fleet, drives the concrete and steel pole replacement requirement
- the data input for the wood pole reinforcement proportion variable is 0% in the future.

In relation to the replacement cost inputs to the model, we have assessed the efficiency of the unit costs and deliverability in Appendix C for this program.

Apart from the wood pole reinforcement proportion assumption from RY25 onwards – which is assessed and commented in detail above – the remaining assumptions adopted by Aurora Energy are not unreasonable given the available data and quality, which is sufficient to provide reliable input to the modelling.

### Data outputs and replacement forecasts

Aurora Energy forecast's is based on a volumetric ( $P \times Q$ ) forecast model and uses the following inputs to determine the volumes (Q):

- the above data inputs – namely, wood pole survivor curve, concrete and steel pole age profile, expected life assumption, and the assumption on future wood pole reinforcement proportion
- removal of a proportion of poles identified within the distribution conductor (POD04) and LV conductor (POD05) replacement forecasts that require replacement due to asset condition during the re-conductoring work (i.e. overlap with this renewal program).

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<sup>253</sup> Based on the review of the category analysis RIN data reported by the Australian EDBs to the AER in recent years and ignoring few outliers. This activity is undertaken by all Australian EDBs in varying degrees as permitted by their respective geographical conditions and risk appetite.

## Validate model outputs

Aurora Energy did not complete any sensitivity analysis for the assumptions in the input data. However, given the methodology adopted by Aurora Energy and that it relied on historical data we do not consider that sensitivity analysis is necessary. Sensitivity analysis of the model output from the changes to input variables (i.e. plotted survivor curve parameters, age profile and expected ages) results in an equal chance of being over/under the presently modelled forecast.

To satisfy ourselves whether the assumptions are reasonable, we compared the modelled volume outputs with two Australian EDBs<sup>254</sup> using published Australian RIN data. Aurora Energy's replacement forecast of approximately 2.2% per annum in the initial years reducing to 1.4% per annum in later years over the review period compare with the replacement rates of between 1.25% and 4% per annum with the Australian businesses.<sup>255</sup> This is a reasonable volume during the review period considering Aurora Energy's historical underspending on poles renewals and the recent catch-up replacement spike in 2018-2019 as part of its 'Accelerated Poles Program'.

### D.3.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of-

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's pole renewal program over the CPP and review periods are that:

- **Inputs and modelling** – the model logic is robust and based on a sound underpinning asset strategy given the asset management maturity context. The model inputs are not unreasonable, especially for the wood poles fleet whereby the distribution profile is based on past replacement experience rather than an estimate of expected life and an estimated statistical distribution.
- **Asset strategy** – Aurora Energy's asset strategy for pole renewals for each asset type is appropriate. However, we expect the asset strategy to be refined to consider the wood pole replacement vs. reinforcement from RY25 onwards as explained in detail in section D.3.8. Our findings on this matter have resulted in the unverified amount as noted in Table C.2 the review period. Poles have traditionally been managed in the industry with a strong focus on safety and pole inspection regimes. This rigour had not been practiced by Aurora Energy in the past, with evident consequences.
- **Benchmarking** – Aurora Energy's proposed replacement rate per annum (inclusive of poles from re-conductoring programs) during the review period is comparable to Australian businesses annual replacement rates. We note that Aurora Energy's long run replacement rate is lower and more stable than that proposed during the review period given the longer life expected with concrete poles.
- **Performance targets** – to support the expenditure objective we expect a distribution company with a mature asset management system to set performance targets for its assets as a measure of the accepted residual risk. The asset performance measure would then be aligned (i.e. have line of sight) with network performance outcomes. Aurora Energy advised in the RFI and workshops<sup>256</sup> that it would be

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<sup>254</sup> SA Power Networks and Western Power.

<sup>255</sup> These values are for the total volume included in the pole, distribution conductor and LV conductor replacement programs.

<sup>256</sup> Poles and Crossarm workshop session on 17/03/2020, P06 – Renewals – Poles and Crossarms 25/03/2020.

establishing performance measures over the CPP period as part of further development of its asset management system.

- **Pole failures** – by comparison with comparable Australian distributors, Aurora’s current unassisted pole failure rate is around four poles per 10,000 pa compared to Australian electricity distribution businesses, which target less than 1 per 10,000 poles pa. Given Aurora Energy’s current asset strategy, we expect that this level of performance is achievable within a 5–10 year timeframe, with corresponding improvement in safety and reliability outcomes. Aurora Energy appears to be managing the fleet to within a reasonable risk profile until this performance outcome is achieved thereby prudently managing the profile of costs incurred and the impact on its network charges paid by consumers.

We consider that the pole replacement expenditure forecast over the CPP period is consistent with the expenditure objective.

This assessment supports respective findings detailed in sections C.3.5 (Assessment of forecast method used), C.3.5.2 (Expenditure Justification) and C.3.5.6 (Interaction with other forecast expenditures).

## D.4 CROSSARMS RENEWALS (R2)

### D.4.1 Information provided

Table D.7 presents the information that has been provided by Aurora Energy relevant to crossarms replacement expenditure modelling and the associated asset strategy of this fleet.

Table D.7: Crossarm renewals information provided

Title	Reference	Date
POD02 – Crossarms	E-16	27 February 2020
MOD02 - Crossarms Renewal Forecast	E-14	27 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
Related overhead lines and poles documents that refers to Approved Equipment and Material Schedule (AE-ND01-G01)	IPC-1012	22 November 2019
<b>Provided in response to our draft report</b>		
Crossarms unit rate explanation (spreadsheet)	PR-12	23 April 2020

### D.4.2 Other information relied on

Table D.8 sets out the other information that we relied on when reviewing Aurora Energy's crossarm replacement expenditure.

Table D.8: Other information relied on

Title	Author	Date
Regulatory Information Notices (RINs) submitted by the Australian electricity distribution businesses <sup>257</sup>	Various Australian EDBs	Various dates
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017

<sup>257</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

Title	Author	Date
Powerline Asset Management Plan	SA Power Networks	January 2019
Independent Review of Electricity Networks	WSP	21 November 2018
EGX 429879 Replace 11kV wood pole (Ellipse system generated job estimate details)	Energex	8 April 2020
Estimate for 11kV crossarms installation job in Western Australia	GHD staff	9 April 2020

### D.4.3 Data and integrity

#### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report. The key sources are:

- **asset attributes** – includes GIS, Structured Lines, Xivic and older records
- **asset condition and performance** – includes above ground visual inspection record (limited to assessing the bottom side of crossarm).

#### Data quality

WSP stated that the asset attribute data for this fleet is low quality, condition data is medium quality, and the performance data is good quality. Aurora Energy utilised available information from the associated pole fleet as proxy by to fill the asset attribute data gaps necessary to estimate crossarm ages.

The assumption appears reasonable – the approach is commonly practiced within the industry. This is also explained in the next section. Asset attributes of lower cost items (such as crossarms) in overhead line assets are usually not accurately and comprehensively recorded. Renewal and maintenance – and therefore record keeping – of overhead line assets can be compared with the ‘grandfather axe’ analogy. Referring to the available asset attribute of a closely associated asset item is a reasonable assumption in such instances.

Aurora Energy has adopted age-based model that only uses the asset attribute data to forecast replacement volumes. Not all available asset data is utilised in this modelling approach. Integrity of the relevant and assumed asset attribute data was sufficient to undertake this expenditure modelling.

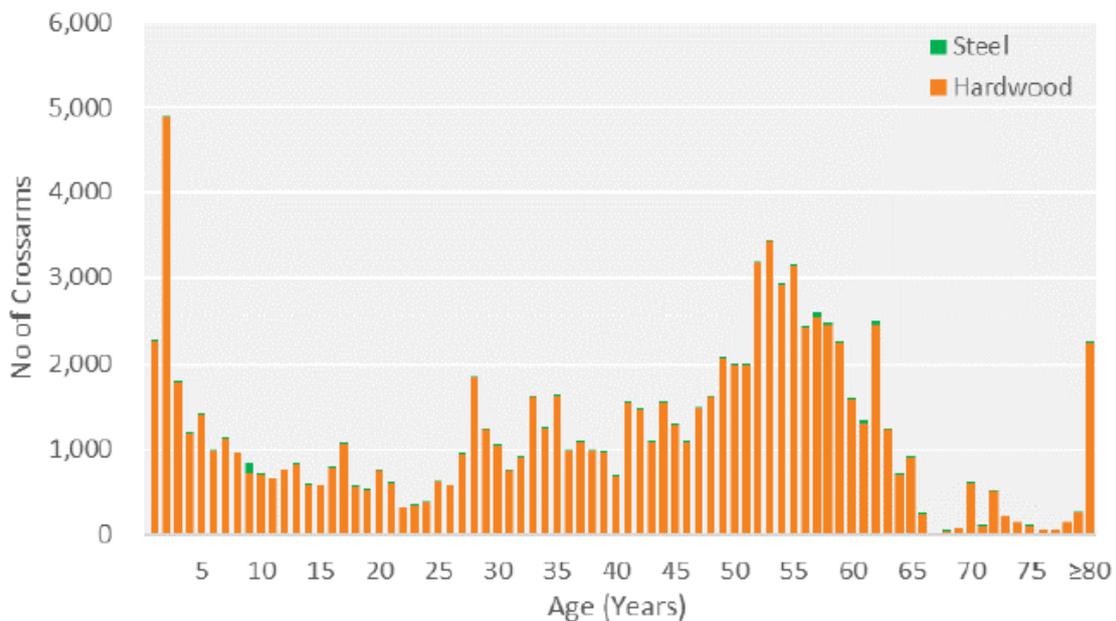
### D.4.4 Asset population and age profile

#### Asset population by age

Aurora Energy has indicated that it owns approximately 95,000 crossarms as of February 2020 in POD02. Most of these are hardwood crossarms and the remaining 680 are steel crossarms.

Where crossarms installation dates were not known, the data had been inferred based on assumption, including the age of associated poles or installed plants. This is not an unreasonable approach to fill in the data gaps for this fleet. Figure D.2 shows the crossarms age profile.

Figure D.2: Crossarms age profile



Source: Aurora Energy, POD02 – Portfolio Overview Document | Crossarms

### Expected Life

Aurora Energy has assumed the expected life for wood crossarms to be 55 years and for steel crossarms to be 75 years. We compared this assumption with the average life of crossarms expected by Australian EDBs.

Given the environmental difference between New Zealand and Australia and its impact on materials, the assumed expected lives for crossarms are not unreasonable.

## D.4.5 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

Aurora Energy has not set any performance objective nor targets for crossarms in terms of asset failures, supply reliability, safety outcomes, supply quality etc. POD02 describes the lack of accurate historical records that can be confidently used to establish asset performance measurements and objectives – such as unassisted crossarms failure rate, or supply impact attributed directly to lack of cross-arm performance, or fire start count, or safety incident count etc. Aurora Energy plans to collect accurate information to build such measurements in the future, which can then be utilised to drive asset management improvements.

### Past performance and forecast performance

The WSP report (page 62) describes the historical pole top structure (i.e. crossarms, insulators) failure and the number of unplanned outages caused. It illustrates that the number of unplanned outages caused exclusively by pole top structure failures has generally remained relatively flat between 10 to 15 per annum in recent years.

Given the limitations in historical data about pole top failures – i.e. records of outages which can be accurately attributed to assisted or unassisted failure modes – we consider that using the available historical data to set up asset performance forecast would be unreasonable without further verification

and analysis due to potential for significant inaccuracies. Accordingly, Aurora Energy presently does not have any asset performance forecast.

#### **D.4.6 Asset condition and modelling**

##### **Asset health / condition and asset subpopulations**

The AHI methodology for crossarms is based on simply the expected life minus the asset age in the model. It is not informed by a condition data from inspections records and hence can only be considered a proxy for asset health. Using this analysis, Aurora Energy then designates percentages of the total fleet of crossarms to H1 to H5 health scores.

Aurora Energy has used an age-based model that assumes crossarms need to be replaced once they reach expected life. This approximates the number of crossarms expected to be found in any one year to need replacement following condition inspections.

Crossarms are not currently further segmented than wood or steel type designation. Further segmentation could be used in the future to have different expected lives for crossarms and to improve the accuracy of forecasts.

#### **D.4.7 Consequence of failure and risk modelling**

##### **Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure**

Public safety is a key driver identified by Aurora Energy in POD02 and is used to prioritise individually identified crossarms for replacement at the delivery stage. The location of the cross-arm determines the criticality rating, which is itself driven by safety considerations only.

Other consequences such as loss load, customer impacted, planning by outage zone, network configuration etc. are not presently considered by Aurora Energy. This is not an unreasonable risk-based approach to achieving a stronger focus on safety.

##### **Risk assessment methodology**

The asset health assessment has not been simultaneously considered with the consequence of failure (i.e. criticality) assessment to determine the risk and to establish an optimum level of forecast replacement expenditure. Instead, the criticality will be assessed after the determination of the forecast expenditure to only prioritise the delivery of work.

Although the methodology for replacement forecasts – based on expected life only – may not yield an optimum forecast, it is consistent with industry practice in circumstances where there is insufficient information to prepare a condition-based forecast.

#### **D.4.8 Asset strategy and renewals model**

##### **Asset strategy**

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish its 2018-28 AMP. POD02 can be viewed as the asset management plan for this fleet, or at least an overview of it. Using a renewal model to forecast replacements for crossarms – which follows age-based asset replacement – is consistent with industry practice when considering the asset management maturity of Aurora Energy.

The maintenance approach for the crossarms fleet is linked to the regime for pole inspection, condition assessment, defect management and fault repairs to retain the asset in service until it is no longer safe or economical to do so. Frequency of the inspection and condition assessment routine is not unreasonable at 5-yearly periods for both activities.

Aurora Energy's uses a volumetric approach – forecast quantities × unit rate – to estimate its proposed expenditure forecast. Expected remaining age is used to forecast quantities and criticality assessment, based on public safety only, is used to prioritise the replacement work delivery.

### Options and data inputs

Aurora Energy has made the following key assumptions:

- **expected lives** – the expected life for wood crossarms to be 55 years and for steel crossarms to be 75 years - the expected life of crossarms is reasonable and together with the age profile of this asset fleet, drives the replacement requirement
- **unit costs** – the unit cost estimate used in the model is based on the weighted average considering the crossarm quantities forecast for replacement between Central and Dunedin regions, and also across all voltage levels.

The above assumptions adopted by Aurora Energy are not unreasonable given that the available data and quality is sufficient to provide reliable input to the modelling. In relation to the replacement cost inputs to the model, we have assessed the efficiency of the unit costs and deliverability in Appendix C for this program.

### Data outputs and replacement forecasts

Aurora Energy's forecast is based on a volumetric P×Q forecast model and uses the following inputs to determine the volumes (Q):

- the above data inputs (i.e. crossarms age profile and expected life assumption)
- removal of a proportion of crossarms identified within the dedicated poles (POD01), distribution conductor (POD04) and LV conductor (POD05) renewal programs that are assumed to require replacement due to asset condition during their respective replacement work (i.e. overlap with this renewal program).

### Validate model outputs

Aurora Energy did not complete any sensitivity analysis for the assumptions in the input data. However, given the input data, assumptions, and methodology adopted by Aurora Energy we do not consider that sensitivity analysis is necessary. Sensitivity analysis of the model output to changes in input variables (i.e. age profile and expected age) results in an equal chance of being over/under presently modelled forecast.

We compared the modelling volume output with two other Australian electricity distribution businesses. Aurora Energy's replacement forecast of approximately 5% per annum over the review period contrasts with the replacement rates of between 0.72% and 0.96% per annum with the compared Australian businesses where both have had a replacement program in place in the previous 10 years.<sup>258</sup>

This higher rate for Aurora Energy's appears due to the historical underspend on crossarms renewals and the present day need to bring down the level of the safety risk. This annual replacement rate gradually

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<sup>258</sup> This covers total volume included in the poles, crossarms, distribution conductor and LV conductor replacement programs.

drops down to 3.4% in the 10 year forecast. There is a potential for the replacement quantities to be above the forecast which will be better informed by condition over the CPP and review periods.

#### D.4.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of-

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's crossarms renewal program over the CPP and review periods are that:

- **Inputs and modelling** – in absence of historical asset failure records, Aurora Energy has relied on the asset age profile, assumed expected asset life and the assumed normal distribution for asset replacement around the expected life in its renewal model. Given the asset management maturity context, we consider these inputs and the assumptions used in the crossarm renewal model to be appropriate and with a sound underpinning asset strategy.
- **Asset strategy** – Aurora Energy's asset strategy for crossarms renewals for each asset type is appropriate given the asset management maturity context and is consistent with industry practice. Crossarms have traditionally been managed in the industry with a strong focus on safety and overhead line inspection regimes. This rigour had not been practiced by Aurora Energy in the past with evident consequences.
- **Benchmarking** – Aurora Energy's forecast replacement rate of 5% per annum (total volume included in the poles, cross-arms, distribution conductor and LV conductor replacement programs) over the review period is much higher than the replacement rates of between 0.72% and 0.96% per annum for the compared Australian businesses. This is mainly due to Aurora Energy's apparent historical underspending on crossarms renewals and the present day need to manage safety risk. While there is a potential for the replacement quantities to be above the forecast once better informed by condition, Aurora Energy's forecast for the CPP and review periods targeted at safety risk concerns is not unreasonable.

Based on our assessment of the CPP proposal and supporting materials over the CPP and review periods, the forecast modelling approach, forecasts for the crossarms replacement over the CPP and review periods and assumed unit appear consistent with the expenditure objective. The top-down efficiency adjustments included in the forecasts appear reasonable.

This assessment supports respective findings detailed in sections C.4.5 (Assessment of forecast method used), C.4.5.2(Expenditure Justification) and C.4.5.6 (Interaction with other forecast expenditures).

## D.5 DISTRIBUTION CONDUCTORS RENEWAL (R3)

### D.5.1 Information provided

Table D.9 presents the information that has been provided by Aurora Energy relevant to distribution conductor replacement expenditure modelling and the associated asset strategy of this fleet.

Table D.9: Information provided

Title	Reference	Date
MOD04 - Distribution Conductors Renewals Forecast	E-15	27 February 2020
POD04 - Distribution Conductor	E-17	27 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FR03-W01 - Conducting Inspections Using Electronic Data Capture	IPC-1033	29 November 2019
AE-NR01-S - Overhead Distribution Design and Construction	IPC-1005	25 November 2019
AE-FR03-F02 - Pole-Line Installation Form	IPC_1039	29 November 2020

### D.5.2 Other information relied on

Table D.10 sets out the other information that we relied on when reviewing Aurora Energy's distribution conductor replacement expenditure.

Table D.10: Other information relied on

Title	Author	Date
Regulatory Information Notices (RINs) submitted by the Australian electricity distribution businesses <sup>259</sup>	Various Australian EDBs	Various dates
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017

<sup>259</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

Title	Author	Date
Powerline Asset Management Plan	SA Power Networks	January 2019
Independent Review of Electricity Networks	WSP	21 November 2018

### D.5.3 Data and integrity

#### Definition of asset data and register

Asset data availability of this fleet was assessed by WSP in its 2018 report. The sources for asset attributes for this fleet includes ArcFM/ArcGIS information, network schematic and route diagrams.

The sources for asset condition information for this fleet is unavailable because there has not been any dedicated inspection or testing programs. The OMS provides limited asset performance information because the faults are not recorded in a manner conducive to accurately track and confidently measure the asset performance of this fleet exclusively.

#### Data quality

WSP stated that the asset attribute data for this fleet is of good quality, condition data low quality, and the performance data low quality. Available asset attribute information has been used to categorise this fleet into various segments based on multiple factors – material, size, voltage level, location etc – to improve the renewal modelling accuracy. In a few instances, Aurora Energy extrapolated or ‘scaled up’ the age profile of the known population of distribution conductors to account for the population with unknown age profile. This is explained further in the next section and is a commonly practiced within the industry in such instances.

Aurora Energy has adopted age-based modelling that only uses the asset attribute data to forecast replacement volumes. Not all available asset data is utilised in this modelling approach. Integrity of the relevant and assumed asset attribute data was sufficient to undertake this expenditure modelling.

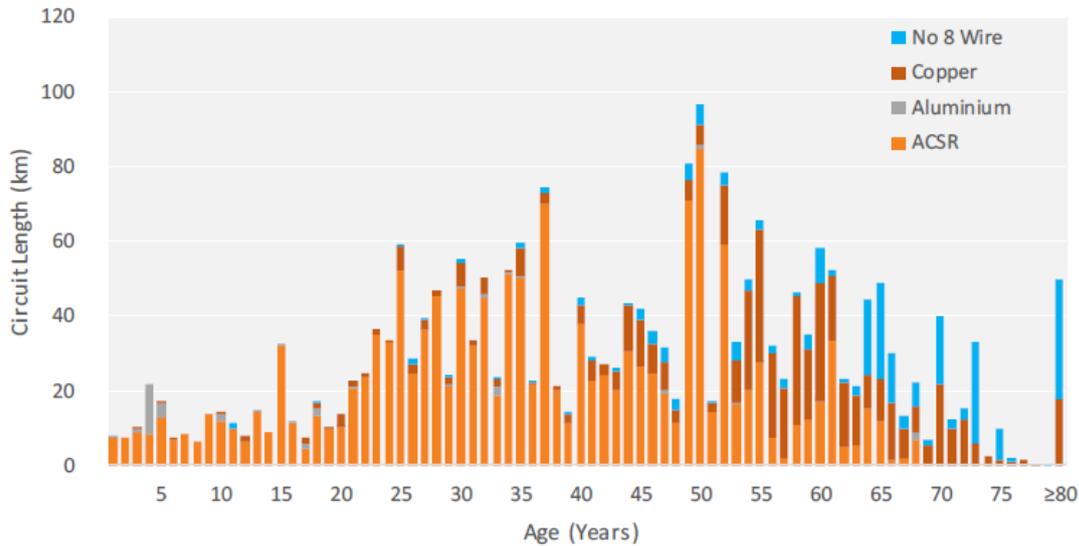
### D.5.4 Asset population and age profile

#### Asset population by age

Aurora Energy has indicated that it owns 2,307km of overhead distribution line as of February 2020 in POD04. Most of these are aluminium-conductor steel-reinforced (ACSR) conductors and the remaining a mix of No 8 wire, copper and aluminium conductors.

As 109km of ACSR conductors have missing installation date information, Aurora Energy assumes an age profile (pro rata) based on the age profile of the remainder ACSR conductors that have that information available. This is not an unreasonable approach to fill in the data gaps for this fleet. Figure D.3 shows the overhead distribution conductor age profile.

Figure D.3: Overhead distribution conductor age profile



Source: Aurora Energy, POD04 – Portfolio Overview Document | Overhead distribution conductor

### Expected life

Aurora Energy has assumed the expected life for distribution conductors to range from 48 to 120 years based on mix of various factors such as conductor type, size and location relative to the coastline with respect to corrosion exposure. This is based on similar ages used by Transpower for its conductor portfolio, which has been informed by condition data.

## D.5.5 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

Aurora Energy has advised that it does not have any performance objective nor targets set for distribution conductors in terms of asset failure count, supply reliability, safety outcome, supply quality etc. The 2018-28 AMP (page 114) describes the limitation of the historical data that can be confidently used as a performance measure for this asset fleet.

### Past performance and forecast performance

Aurora Energy has used the sub-set of unplanned SAIFI data that is attributable to overhead conductor – and not just only to the conductors – as a proxy for asset failure in the 2018-28 AMP (page 115). While the recent historical trend line of this performance indicates an increase in failures, this inference is not strong, especially given the accuracy, root cause recording and limitations relevant to the historical records.

Aurora Energy plans to collect accurate and relevant information to build such measurements in the future (such as unassisted conductor drops), which it can then use to drive asset management improvements and provided better informed expenditure forecasts.

## D.5.6 Asset condition and modelling

### Asset health / condition and asset subpopulations

The AHI methodology for distribution conductor is based on simple expected life minus the asset age in the model and is not at this point informed by actual condition information. Sampling of replaced

conductors during the CPP and review periods will improve the asset health model to be calibrated based more on condition.

Using this analysis, Aurora Energy assigned percentages of the total fleet of distribution conductor to the H1 to H5 health scores, which then categorises the quantities required for future replacement based on remaining life.

The distribution conductor fleet is segmented by asset types and further segmented by corrosion zones, which is currently good industry practise.

### **D.5.7 Consequence of failure and risk modelling**

#### **Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure**

Public safety is a key driver identified by Aurora Energy in POD04 and throughout its CPP proposal supporting material, and will be used to prioritise an individual identified feeder or section of a distribution conductor for replacement at the delivery stage.

The distribution conductor location determines the criticality rating assigned to conductors, with such a rating driven by safety considerations only. Other consequences such as loss load, customer impacted, planning by outage zone, network configuration etc. are not presently considered by Aurora Energy as far as we could tell.

This is not an unreasonable risk-based approach to achieving a stronger focus on safety.

#### **Risk assessment methodology**

The asset health assessment used by Aurora Energy to forecast asset replacements has not factored in failure consequences (i.e. criticality) to determine risk nor to establish an optimum level of forecast replacement volumes. Instead, Aurora Energy intends to assess criticality once forecast expenditure is set and only then to prioritise the delivery of work.

We consider that this methodology does not yield an optimum forecast and some replacement projects may proceed within the CPP or review periods that could have been deferred beyond the period if risk was factored in. However, at present there appears to be insufficient information available to Aurora Energy to refine its forecasts to do this. Given this, the volumes forecast are not unreasonable based on the circumstances and the overall safety risk associated with distribution conductors.

### **D.5.8 Asset strategy and renewals model**

#### **Asset strategy**

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish its 2018-28 AMP. POD04 can be viewed as the asset management plan for this fleet, or at least an overview of it. Using a renewal model to forecast distribution conductor replacements that uses an age-based asset replacement approach is consistent with GEIP when considering the asset management maturity of Aurora Energy.

Aurora Energy's maintenance approach of distribution conductor is linked to the pole regime of inspection, condition assessment, defect management and fault repairs to retain asset in service until it is no longer safe or economical to do so. Condition assessment focuses on defects such as broken strands,

clashing, conductor bulges or tree encroachment. Frequency of the inspection and condition assessment routine is reasonable at a five yearly period for both activities.

Aurora Energy uses a volumetric approach (forecast quantities  $\times$  unit rate) to calculate the proposed conductor renewal expenditure forecast. Remaining age is used to forecast quantities. Criticality assessment (focusing on public safety only) is used to prioritise the replacement for work delivery.

The above asset strategy is consistent with industry practice for the asset fleet; however, using a volumetric forecasting approach without calibrating this with historical condition data may result in higher forecast expenditure than is needed. That said, in our view, this is not likely to be the case during the CPP and review periods. The volumes appear warranted due to the lack of condition data and the inherent safety and reliability risks with this asset fleet.

### **Options and data inputs**

Aurora Energy has made the following assumptions:

- Expected lives of distribution conductors are reasonable and together with the age profile of this asset fleet, drives the replacement requirement.
- Every km of re-conductoring assumes a proportion of poles in the route (and the corresponding 1.7 crossarms/pole) to be replaced in the scope of work, i.e. not all the poles in the route are replaced during re-conductoring. The unit cost estimate is derived from recent projects and the underlying details aligns with this assumption. Within this proportion of poles and crossarms, only a portion is assumed to require replacement based on condition which has been accordingly reconciled or removed from the respective dedicated renewal programs (i.e. POD01 and POD02).
- Under clearance spans (195) have been identified for replacement during the review period. This is based on a survey of compliance with clearance requirements in NZ ECP34 on NZTA designated haulage routes.

We are comfortable with Aurora Energy's modelling approach, using age data, and alignment between the pole and crossarm replacements identified in this renewal program and those included in the pole (POD01) and crossarm (POD02) renewal programs.

### **Data outputs and replacement forecasts**

Aurora Energy's forecast is based on a volumetric  $P \times Q$  forecast model and uses the following inputs to determine the volumes (Q):

- the above data inputs – namely, distribution conductor age profile and expected life assumption)
- the identified under-clearance spans that require replacement.

The unit cost replacement for both re-conductoring and under clearance span works have been applied correctly. We assess efficiency of unit costs and deliverability in Appendix C for all the programs.

### **Validate model outputs**

Aurora Energy did not complete any sensitivity analysis for the assumptions in the input data. However, given the input data and methodology adopted by Aurora Energy we do not consider that sensitivity analysis is necessary. Sensitivity analysis of the model output to changes to input variables (i.e. age profile and various expected ages) results in an equal chance of being over/under presently modelled forecast.

We compared the modelling volume output with two other Australian electricity distribution businesses. Aurora Energy's replacement forecast of approximately 1.3% per annum in average over the review

period contrasts with the replacement rates of between 0.08% and 0.6% per annum with the compared Australian businesses, which had programs in place over the last 10 years.

Comparatively, Aurora Energy's higher rate does not appear unreasonable given the underspend on dedicated distribution conductor renewals in the past and the need to reduce associated safety risks. There has been no historical standalone renewal program for this asset fleet.

### D.5.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of-

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's distribution conductor renewal program over the CPP and review periods are that:

- **Inputs and modelling** – Aurora Energy's age-based modelling approach is not unreasonable for the Distribution Conductors renewal program forecast. The proportion of reconciliation assumed for the poles and crossarms identified in this replacement program with poles (POD01) and crossarms (POD02) replacement programs appears appropriate.
- **Benchmarking** – focusing only on the circuit km of the conductor, Aurora Energy's replacement forecast of approximately 1.3% per annum on average over the review period is noticeably higher than the replacement rates of between 0.08% and 0.6% per annum for comparable Australian businesses. However, this is not unreasonable in the circumstances, as the higher replacement rate for Aurora Energy appears due to historical underinvestment and the need to reduce safety risks.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the distribution conductor replacement are not unreasonable over the CPP and review periods.

This assessment supports respective findings detailed in sections C.5.5 (Assessment of forecast method used), C.5.5.2 (Expenditure Justification) and C.5.5.6 (Interaction with other forecast expenditures).

## D.6 LV CONDUCTOR RENEWALS (R4)

### D.6.1 Information provided

Table D.11 presents the information that has been provided by Aurora Energy relevant to LV conductor replacement expenditure modelling and the associated asset strategy of this fleet.

Table D.11: Information provided

Title	Reference	Date
POD05 - LV Conductor	E-29	28 February 2020
MOD05 - LV Conductors Renewals Forecast	E-30	28 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FR03-W01 - Conducting Inspections Using Electronic Data Capture	IPC-1033	29 November 2019
AE-NR01-S - Overhead Distribution Design and Construction	IPC-1005	25 November 2019
AE-FR03-F02 - Pole-Line Installation Form	IPC-1039	29 November 2019

### D.6.2 Other information relied on

Table D.12 sets out the other information that we relied on when reviewing Aurora Energy's LV conductor replacement expenditure.

Table D.12: Other information relied on

Title	Author	Date
Regulatory Information Notices (RINs) submitted by the Australian electricity distribution businesses <sup>260</sup>	Various Australian EDBs	Various dates
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017

<sup>260</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

Title	Author	Date
Powerline Asset Management Plan	SA Power Networks	January 2019
Independent Review of Electricity Networks	WSP	21 November 2018

### D.6.3 Data and integrity

#### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report. Asset attribute information for this fleet is available from ArcFM/ArcGIS information, network schematic and route diagrams.

Asset condition information for this fleet is unavailable because there has not been any dedicated inspection or testing programs. The OMS provides limited asset performance information because the faults are allocated to the nearest distribution transformer and the downstream LV feeders are not consistently recorded.

#### Data quality

WSP stated that overall, the asset attribute data for this fleet was of medium quality, condition data low quality, and the performance data low quality. Available asset attribute information has been used to categorise this fleet into various segments based on multiple factors – material, size, voltage level, location etc. – to improve the renewal modelling accuracy. Aurora Energy extrapolated or scaled up the age profile of the known population of LV conductors to account for the population with unknown age profile. This is explained further in the next section and is a commonly practiced within the industry in such instances.

Aurora Energy has adopted age-based modelling that only uses the asset attribute data to forecast replacement volumes. Not all available asset data is utilised in this modelling approach. Integrity of the relevant and assumed asset attribute data was sufficient to undertake this expenditure modelling.

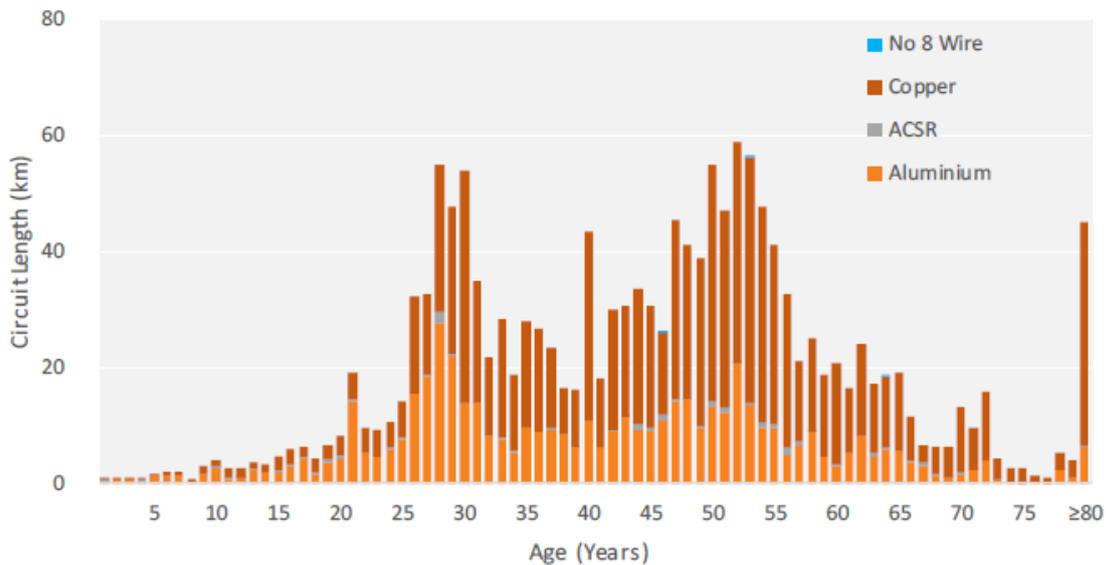
### D.6.4 Asset population and age profile

#### Asset population by age

Aurora Energy has 1,577km of overhead LV conductor as of February 2020. Most of these are copper and aluminium conductors. The remaining very few are No 8 wire and ACSR conductors.

As 40% of this asset fleet does not have a known installation date recorded, Aurora Energy has assumed an age profile (pro rata) based on the age profile of those in the fleet that do. This is not an unreasonable approach to fill in the data gaps for this fleet. Figure D.4 shows the overhead LV conductor age profile.

Figure D.4: Overhead LV conductor age profile



Source: Aurora Energy, POD05 – Portfolio Overview Document | Overhead LV conductor

### Expected life

Aurora Energy has assumed the expected life for LV conductors to range from 48 to 120 years based on mix of various factors such as conductor type, size and location relative to the coastline with respect to corrosion exposure. This is based on similar age used by Transpower for its conductor portfolio, which was informed by condition.

## D.6.5 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

Aurora Energy has advised that it does not have any performance objective or targets set for LV conductors in terms of asset failures, supply reliability, safety outcomes, supply quality etc.

The 2018-28 AMP (page 114) describes the limitation of the historical data that can be confidently used as a performance measure for this asset fleet. Also, Aurora Energy has not historically collected LV outage data, so presently the supply reliability vs performance of LV conductor cannot be assessed.

### Past performance and forecast performance

Aurora Energy has used the sub-set of unplanned SAIFI data that is attributable to distribution conductors – within outage data records – as a proxy for asset failure in the 2018-28 AMP (page 115).

While the recent historical trend line of this performance indicates an increase in conductor related SAIFI, this inference is not strong, especially given the accuracy, root cause recording, and limitations relevant to the historical records and also the fact that LV outage data has not been historically captured. Due to data limitations, Aurora Energy can only rely on anecdotal evidence of LV conductor failures.

Aurora Energy plans to update its processes and systems to allow for future recording of LV conductor failure associated with supply reliability measurement. Such measurement will allow improvements to asset strategies and provide better informed expenditure forecasts.

## D.6.6 Asset condition and modelling

### Asset Health/Condition and asset subpopulations

The AHI methodology for LV conductor is based on simple expected life minus the asset age in the model and is not at this point informed by actual condition. Sampling of replaced conductors during the CPP and review periods will improve the asset health model by allowing it to be calibrated using condition information.

Using this analysis, Aurora Energy assigns percentages of the total fleet of LV conductor to the H1 to H5 health scores, which then categorises the quantities required for future replacement based on remaining life.

The LV conductor fleet is segmented by asset types and further segmented by corrosion zones which is currently good industry practise.

## D.6.7 Consequence of failure and risk modelling

### Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure

Public safety is a key driver identified by Aurora Energy in POD05 and throughout its CPP proposal supporting material, which will be used to prioritise individual identified feeders or sections of a LV conductor for replacement at the delivery stage.

The LV conductor location determines the criticality rating assigned to conductors, with such a rating driven by safety considerations only. Other consequences such as loss load, customer impacted, planning by outage zone, network configuration etc. is not presently considered by Aurora Energy.

This is not an unreasonable risk-based approach to achieving a stronger focus on safety.

### Risk assessment methodology

The asset health assessment used by Aurora Energy to forecast asset replacements has not factored in failure consequences (i.e. criticality) to determine risk nor to establish an optimum level of forecast volumes. Instead, Aurora Energy intends to assess criticality once forecast expenditure is set and only then to prioritise the delivery of work.

We consider that this methodology does not yield an optimum forecast and some replacement projects may proceed within the CPP or review periods that could have been deferred beyond the period if risk was factored in. However, at present there appears to be insufficient information available to Aurora Energy to refine its forecasts to do this. Given this, the volumes forecast are not unreasonable based on the circumstances and the overall safety risk associated with LV conductors.

## D.6.8 Asset strategy and renewals model

### Asset strategy

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish the 2018-28 AMP. POD05 can be viewed as the asset management plan for this fleet, or at least an overview of it. The renewal model for LV conductor uses an age-based asset replacement approach, which is consistent with industry practice when considering the asset management maturity of Aurora Energy.

Aurora Energy's proposed maintenance of LV conductors is linked to its proposed pole maintenance regime for inspections, condition assessments, defect management and fault repairs to retain asset in service until it is no longer safe or economical to do so. Condition assessment focuses on defects such as broken strands, clashing, conductor bulges or tree encroachment. Frequency of the inspection and condition assessment routine is not unreasonable at five yearly periods for both activities.

Aurora Energy uses a volumetric approach – i.e. forecast quantities  $\times$  unit rate – to estimate its proposed expenditure forecast. Remaining age is used to forecast quantities. Criticality assessment that focuses on public safety only is used to prioritise the replacement for work delivery.

The above asset strategy is consistent with industry practice for the asset fleet, however the volumetric forecasting approach without historical condition data may result in higher forecast expenditure than is reasonable. However, in our view, this is not likely to be the case during the CPP and review periods. The volumes appear warranted due to the lack of the data and inherent safety and reliability risk with this asset fleet.

### **Options and data inputs**

The following assumptions have been made:

- expected lives of LV conductors are reasonable and together with the age profile of this asset fleet – which drives the replacement requirement
- every km of re-conductoring requires a fixed proportion of poles in the route (and the corresponding 1.7 crossarms/pole) to be replaced in the scope of work – which means that not all the poles in the route are replaced during re-conductoring.
- within this proportion of poles and crossarms, only a portion is assumed to require replacement based on condition – this portion of poles and crossarms has been reconciled or removed from the respective dedicated renewal programs (i.e. POD01 and POD02).
- given that Aurora Energy has not performed any LV re-conductoring project in recent times, the unit cost estimate for this asset fleet was based on distribution line re-conductoring work and adjusted (scaled down) for comparative size, scale, and ease of work and materials – this adjusted cost was then compared with an independently sourced information.

We are comfortable with this this modelling approach, the use of the age data, and the reconciliation assumed for the poles and crossarms identified in this replacement programs with poles (POD01) and crossarms (POD02) renewal programs.

### **Data outputs and replacement forecasts**

The model is based on a volumetric  $P \times Q$  forecast model and uses the following inputs to determine the volumes (Q):

- the above data inputs – namely, the LV conductor age profile and expected life assumption
- the unit cost replacement for re-conductoring have been applied correctly – we have addressed assessment of the efficiency of unit costs and deliverability in Appendix C for all the programs.

### **Validate model outputs**

Aurora Energy did not document any sensitivity analysis conducted for the assumptions in the input data. However, such analysis is not necessary given the input data and methodology used for this asset fleet. Sensitivity analysis of model output to changes in input variables (i.e. age profile and various expected ages) results in an equal chance of being over/under presently modelled forecast.

We compared the modelling volume output with two other electricity distribution businesses. Aurora Energy's replacement forecast of approximately 2% per annum in average over the review period contrast with the replacement rates of between 0.2% and 0.8% per annum with the compared Australian businesses, which had programs in place over the last 10 years.

Aurora Energy's higher rate does not appear unreasonable given it has not had a dedicated LV conductor renewal program in the past leading to some asset degradation and the need to reduce the associated safety risks.

### D.6.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of-

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's LV conductor renewal program over the CPP and review periods are that:

- **Inputs and modelling** – the age-based modelling approach used by Aurora Energy for this renewal program forecast is not unreasonable. The proportion of reconciliation assumed for the poles and crossarms identified in this replacement programs with poles (POD01) and crossarms (POD02) replacement programs looks appropriate.
- **Benchmarking** – focusing only on the circuit km of the conductor, Aurora Energy's replacement forecast of approximately 2% per annum in average over the review period contrast with the replacement rates of between 0.2% and 0.8% per annum with the compared Australian businesses. However, this is not unreasonable in the circumstances, as the higher replacement rate for Aurora Energy appears due to historical underinvestment and the need to reduce safety risks.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the LV conductor replacement do not appear inconsistent with the expenditure objective over the CPP and review periods.

This assessment supports respective findings detailed in sections C.6.5 (Assessment of forecast method used), C.6.5.2 (Expenditure Justification) and C.6.5.6 (Interaction with other forecast expenditures).

## D.7 ZONE SUBSTATION RENEWALS (R5)

### D.7.1 Assessment of zone substation renewal models

The zone substation portfolio forecast consists of five fleets:

- **power transformers** – cover power transformers, bunding, oil containment, firewalls and neutral earthing transformers
- **indoor switchgear** – 6.6 to 33 kV indoor switchgear within zone substation buildings
- **buildings and grounds** – buildings that house indoor switchgear and secondary systems equipment. It also includes fences, access ways, security and switchyard earthing
- **outdoor switchgear** – circuit breakers, air-break switches and reclosers located in outdoor switchyards
- **ancillary zone sub equipment** – mobile zone substation, load management and shunt capacitor equipment.

Power transformers, outdoor and indoor switchgear have been assessed separately in sections D.8, D.9 and D.10 respectively. This section provides a review of the other assets within the zone substation portfolio and collectively where relevant with these three main asset classes. This section provides an overall review of the MOD19-Zone substation coordination model.

### D.7.2 Information provided

Table D.13 presents the information that has been provided by Aurora Energy generally relevant to the zone substation fleet.

Table D.13: Information provided

Title	Reference	Date
MOD09 – Zone Substation Coordination Model	E-37	28 February 2020
POD09 – Zone Substation	E-38	28 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
P11 – Renewals – Zone Subs & Protection	V-99	26 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FA15-F01 - Technician Check Sheet	IPC-1057	29 November 2019
AE-FA15-F02 - Outdoor Structure Maintenance Form	IPC-1052	29 November 2019
AE-FR03-F01 - Monthly Substation Inspection Form	IPC-1040	29 November 2019
AE-FR03-F03 - Earth Installation Test Report	IPC-1040	29 November 2019

Title	Reference	Date
AE-FA14-F05 - Zone Substation Earth Grid Continuity Test	IPC-1055	29 November 2019
RFIs D001-D027, DD139 and D352	RFI responses set out in Table I.2	Late March, Early April 2020
<b>Provided in response to our draft report</b>		
Notes regarding updated MOD09	PR-3	21 April 2020

### D.7.3 Other information relied on

Table D.14 sets out the other information that we relied on when reviewing Aurora Energy’s zone substation replacement expenditure.

Table D.14: Other information relied on

Title	Author	Date
Regulatory Information Notices (RINs) submitted by the Australian electricity distribution businesses <sup>261</sup>	Various Australian EDBs	Various dates
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017
Powerline Asset Management Plan	SA Power Networks	January 2019
Asset Management Plan 2019	Powerco	2019
Independent Review of Electricity Networks	WSP	21 November 2018

### D.7.4 Data and integrity

#### Definition of asset data and register

The asset data availability for this fleet was assessed by WSP in its 2018 report. Two key data sources were the GIS and the maintenance schedules spreadsheets.

The data on buildings has been enhanced following seismic assessments conducted in 2015.<sup>262</sup>

#### Data quality

There appears to be sufficient data related to buildings and ancillary equipment. It is not uncommon though in the electricity industry, that data on buildings are not to the same standard as the core electrical network assets.

<sup>261</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

<sup>262</sup> 2015 comprehensive fire, security and seismic risk assessment report for civil infrastructure assets at zone substations.

### D.7.5 Asset population and expected life

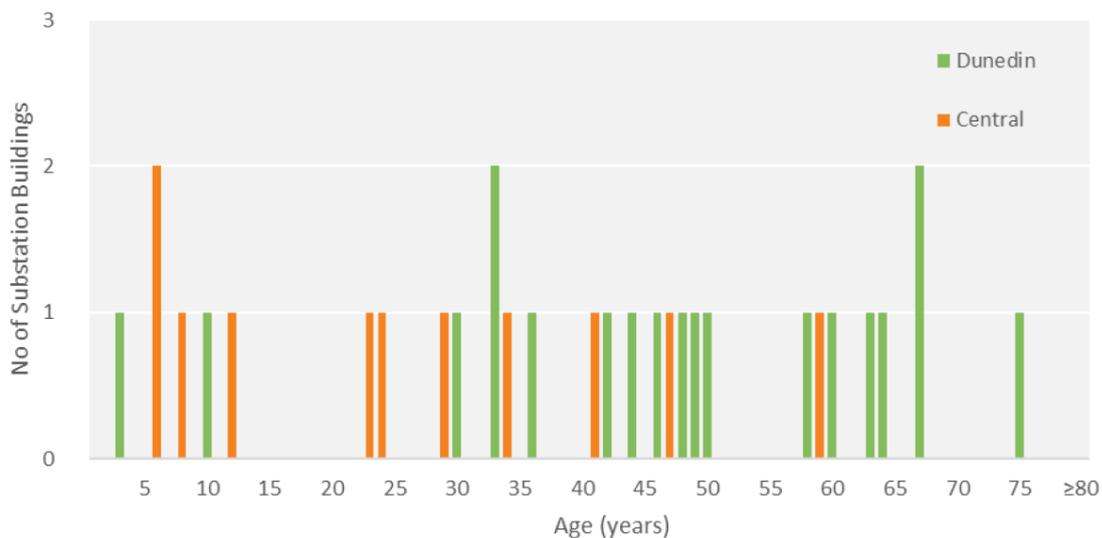
#### Buildings and grounds

Aurora Energy has indicated that it owns 30 substation buildings (not all zone substations contain buildings) with a significant number of them established between 1950 and 1970. The average age is 39 years for all regions but an older average age in the Dunedin region at 46 years. One building is over 70 years of age. Figure D.5 shows the zone substation building age profile.

Aurora Energy has not defined expected lives for its buildings which in general is valid in that civil structures can continue to be maintained and refurbished except if replacement is required due to changes to building standards.

We consider that components within the substation, such as electro-mechanical systems, roofs and ceilings, earthing, fencing and oil containment systems should have defined lives for the purpose of managing related reliability, safety and environmental risks.

Figure D.5: Zone substations building age profile



Source: Aurora Energy, POD09 – Portfolio Overview Document | Zone Substations

#### Ancillary equipment

The ancillary equipment asset fleet includes equipment in the zone substations that do not fit into one of the other categories, for example, ripple control equipment, outdoor structures, the mobile zone substation and shunt capacitor equipment.

Aurora Energy is not planning for any renewal of ripple injection equipment or capacitor banks during the review period. There was no data on age or condition provided by Aurora Energy in POD08 regarding these assets.

### D.7.6 Asset condition – buildings and ancillary equipment

Seismic assessments conducted in 2015, also covering overall structural integrity, found that 20 of the 26 zone substation buildings assessed did not fully meet the Importance Level 3 (IL3) standard. Most of the lower rated buildings were built prior to 1970.

New buildings will be designed to an IL4 standard. Aurora Energy has developed detailed designs for seismic strength upgrades of existing buildings to 100% of the New Building Standard (NBS) for the IL3 standard.

Security of the zone substations is critical for public safety. Aurora Energy is planning to implement a program of security upgrades at the zone substations over the next three years, to ensure that access can be appropriately managed, in a manner that meets obligations under the Electricity (Safety) Regulations.

We did not find any information specifically related to the general condition of the buildings regarding structural elements that could have consequences to substation reliability and security. Though maintaining the building to meet the ongoing requirements of IL3 should provide for the building elements to be structurally sound.

The condition of fencing with respect to preventing forced substation entry was not addressed in POD08. We consider the integrity of fencing to be an important asset for substation security that requires particular attention.

There are no AHI models applied to the zone substation buildings or ancillary equipment. There is little benefit from an asset planning perspective; however, from an asset health dashboard perspective, with data based on condition assessments an overall view of the state of assets is available to stakeholders.

The building assets could be segmented to identify the state of higher risk components such as roofs, ceilings, fences, earthing and oil containment facilities.

### **D.7.7 Consequence of failure and risk Modelling**

#### **Failure modes and consequences (safety, reliability, quality, other)**

The key failure modes considered are seismic events and security of the substations.

#### **Risk assessment methodology**

Risk assessments have not been specifically applied to buildings and ancillary equipment. Risk associated with buildings appear to be limited to compliance consideration to the New Building Standard (NBS) and for security to the locks on gates and doors to buildings. We consider that in a mature asset management system, these assets are also treated with an appropriate asset health and criticality framework.

### **D.7.8 Asset strategy for building and ancillary equipment**

The renewal strategy for buildings surrounds the seismic strength upgrades of buildings which do not currently fully comply with the NBS for the IL3 standard. These seismic remediation works are progressing with an expected completion at the end of RY21.

Aurora Energy plans to replace the buildings at three zone substations during the review period (Andersons Bay, Green Island and Clyde-Earnsclough). The primary driver for these replacements is the lack of space in the existing buildings for new indoor switchgear. The condition of the buildings and seismic risk are secondary drivers. The plans also include building new switch rooms at Alexandra and Mosgiel to house new 33 kV switchboards (outdoor to indoor 33 kV switchgear conversions).

The plan includes the replacement of the buildings at four of the lowest rated zone substations, and to undertake reinforcements such as strengthening of masonry of a further eight. The building at North City was to be made redundant or relocated due to the new Dunedin Hospital although this need has changed recently.

The AMP 2018-2028 states the maintenance of substation buildings, ground and fences includes bi-weekly ground maintenance, annual fire protection and five-year asbestos testing. There was no mention of annual building inspections however we assume this would be undertaken annually.

Ancillary equipment includes one or two year maintenance of ripple control systems, five yearly earth grid testing and six month inspection of the mobile substation.

The above asset strategy is consistent with industry practice for this asset fleet.

### D.7.9 Zone substation renewal forecasting

Aurora Energy has used a separate tool, the coordination tool, to review the entire portfolio of asset replacements in the zone substation portfolio to develop optimised project timing. The coordination tool aims to ensure:

- equipment is replaced in a coordinated manner so that all replacements occurring in the five year period are bundled into a single project along with consideration of growth project requirements over the period
- renewal (and growth) projects are programmed to occur in an orderly manner and the overall program of work is deliverable.

In response to our RFIs Aurora Energy confirmed the following in relation to how it considered options in the planning of the zone substation projects.

- During the development of the customised estimates for the projects different options are considered. However, in most cases Aurora Energy did not identify any sufficiently viable options to progress its exploration and hence only documented short listed options. Based on its assessments, Aurora Energy has planned to decommission one small zone substation (Earnsclough) rather the option of renewing the substation.
- RFI D334 asked about options considered when scoping each substation project. Aurora Energy provided details of several options considered for two projects, Anderson Bay and Queenstown which were not included in POD08.
- RFIW482 asked about business cases and option analysis. Aurora Energy provided three separate concept designs which included considered options for three zone substation projects; Andersons Bay, Queenstown Switchyards and Smith Street 11 kV switchgear. We note that a consultant recommended to renew the entire Smith Street substation site, however, Aurora Energy chose to defer the replacement of the power transformers to later in the 10-year planning period. This is further discussed under Power Transformers.

Specific customised concept designs and capital cost estimates have been prepared for each of the identified building projects. We have reviewed them and agree with the overall project scopes and cost estimates to the extent that we are able to verify the included scope.

Customised cost estimates have been prepared for each of the asset renewal projects by:

- reviewing the existing configuration/layout of the relevant zone substation (using drawings and pictures)
- determined whether like-for-like replacement is a sensible/optimal approach (i.e. via options analysis)
- itemising the equipment required to be replaced
- using the price-book to determine the total customised cost estimate
- reviewing each of the total customised cost estimates in the light of other similar project costs.

Following discussions with Aurora Energy regarding the prioritisation of two 11 kV switchboards, Aurora Energy updated its forecasts (in MOD09) with the following changes:

- the replacement of the South City 11 kV Switchboard has been deferred from RY25 to RY30 based on risk / need
- the deferral of the South City 11 kV switchboard enabled other higher risk substitute projects to be brought forward to achieve a balance of deliverability and prioritisation:
  - Smith Street 11 kV switchboard replacement brought forward 2 years to achieve RY24 commissioning
  - Port Chalmers transformer replacement delayed by one year to RY25
  - Dalefield substation rebuild brought forward by one year to achieve RY26 commissioning.

The timing of some growth-related major projects has changed as a result of early COVID-19 impact assessments. The need to re-evaluate renewal needs covered by growth projects and the above changes resulted in a small increase to the zone substation forecast over the CPP and review periods.

### D.7.10 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of-

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's zone substation renewal program over the CPP and review periods are that:

- the coordination model is a good method to consider and challenge the potential works into separate zone substation projects to enable the efficiencies to be gained in bundling work into specific site projects over the 10-year planning horizon
- the forecasting and coordination planning model for zone substation projects has been successfully used to review and optimise a project schedule for the delivery of zone substation projects over the CPP period and the 10-year forecast
- Aurora Energy has tested and considered options for each substation project leading to final concept designs and estimates
- the required building renewals forecast for the CPP and review periods are not unreasonable
- when developing the asset management system, building assets should also be treated with an appropriate asset health and criticality framework covering fencing, structural integrity and security.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the zone substation renewal program do not appear inconsistent with the expenditure objective over the CPP and review periods.

This assessment supports respective findings detailed in sections C.7.5 (Assessment of forecast method used), C.7.5.2 (Expenditure Justification) and C.7.5.6 (Interaction with other forecast expenditures).

## D.8 POWER TRANSFORMER RENEWALS (R5.1)

### D.8.1 Information provided

Table D.15 presents the information that has been provided by Aurora Energy specifically relevant to the power transformers replacement volumes and renewal model MOD09a – Power Transformers risk model.

The zone substation portfolio includes a total of 65 power transformers, 29 in Central zone substations and 36 in Dunedin. The sizes of the power transformers range from 2 MVA to 30 MVA and typically have winding voltages of 33/6.6 kV, 33/11 kV and 66/11 kV.

Table D.15: Information provided

Title	Reference	Date
POD09 – Zone Substation	E-38	28 February 2020
P11 – Renewals – Zone Subs & Protection	V-99	26 March 2020
MOD09a - Power Transformers risk model.xlsx	V-105	26 March 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-FM15-W01 - Zone Substation Maintenance	IPC-1332	24 December 2019
Zone substation cost estimates (customised cost estimate build-up of 14 renewal projects)   MOD09-01 to MOD09-10, 13, 19, 22 and 26	E-40 to E-53	28 February 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FA15-F01 - Technician Check Sheet	IPC-1057	29 November 2019
AE-FM16-F01 - Tap Changer Maintenance	IPC-1042	29 November 2019
AE-FR01-F03 - Surge Arrester Installation	IPC-1371	10 March 2020
AE-FR01-F03 - Transformer Installation	IPC-1369	10 March 2020
AE-NT02-F01 - Tap Change Request Form	IPC-1002	29 November 2019
RFIs D001-D027, DD139 and D352	RFI responses set out in Table I.2	Late March, early April 2020

Title	Reference	Date
<b>Provided in response to our draft report</b>		
MOD09 - Zone Substation Coordination Model - Post IV review	PR-2	21 April 2020
Notes regarding Updated MOD09 - Zone Substations Coordination model	PR-3	21 April 2020

## D.8.2 Data and integrity

### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report finding that some data quality gaps required validation. WSP found that the data held by Aurora Energy for transformers is good however the accessibility of the data was not straight forward as it is spread over many separate documents and systems including the ArcFM/ArcGIS systems.

Aurora Energy is continuing to update and collect missing data for the future implementation of an EAM system.

### Data quality

WSP found that the asset attribute data for this transformer fleet was of good quality including condition and performance data. Some areas have required validation and correction during the preparation of the asset plan and forecast. The model uses this condition data to map into asset health index ratings for the risk modelling stage of this model. The condition data appears to be of sufficient quality for this purpose.

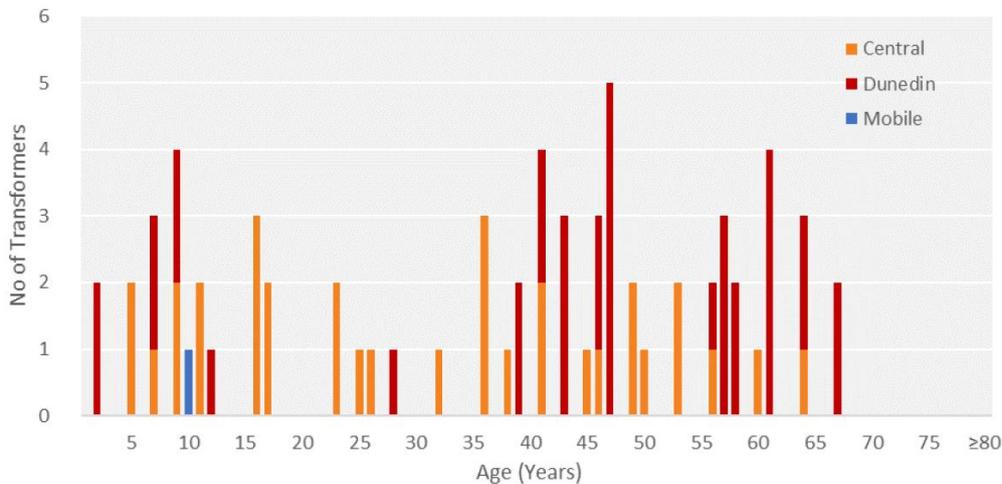
## D.8.3 Asset population and age profile

### Asset population by age

Aurora Energy has 65 power transformers with an average age of 38 years. Power transformers in the Dunedin region have a substantially higher average age of 44 years compared to 31 years for the Central region.

Nine of the power transformers have exceeded 60 years of age, one of which has exceeded 65 years at Outram in the Dunedin region.

Figure D.6: Power transformer age profile



Source: Aurora Energy, POD08 – Portfolio Overview Document | Zone Substations

### Expected life

Aurora Energy has determined the expected life for power transformers to be 60 years. Based on comparison with the Australian distributors the expected life of power transformers ranges from 55 to 75 years.

Asset strategies for power transformers typically rely less on nameplate age and more on diagnostic testing to determine actual operating and remaining life. Aurora Energy in its model to forecast required replacements weights various factors including age and diagnostics tests to assess the probability of a major failure. Our assessment of the model – which is detailed below in this section – indicates the mapping of one data input could have potentially led to earlier timing for replacements in the forecast.

## D.8.4 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

There are no specific performance objective or targets set for the power transformers but indirectly a targeted performance is established through the risk models which inherently defines the accepted residual risk. The model itself developed for transformers is of a high standard considering the journey in which Aurora Energy is undergoing in developing the maturity of its asset management system and practices.

### Past performance and forecast performance

In POD08, Aurora Energy's rate of major failures for its power transformers equates to 1.3% per annum with six major transformer failures recorded over the last 13 years. Power transformer failures are relatively rare and as quoted in the POD, an Australia/New Zealand CIGRE survey showed a probability of total major and minor failure of power transformers is approximately 1.0% per year. Major failures reported in RIN data statistics for Australian utilities range between 1 to 3 units per 1,000 units per year (i.e. 0.1% to 0.3%).

Historically it appears that Aurora Energy has allowed transformers to operate beyond acceptable risk levels or that maintenance has not been adequate, resulting in failures. We have been unable to confirm whether past maintenance practices have been a factor in past failures but are of the view that maintenance was likely to have been a contributor to the past high failure rates.

The current risk model is aimed at mitigating this outcome. We consider that Aurora Energy could have established interim performance measures for its transformer fleet at this stage of the development of its asset management system. Aurora Energy has stated that performance measures will be developed during the CPP period.

### D.8.5 Asset condition and modelling

#### Asset health / condition and asset subpopulations

The asset health model for power transformers is well advanced like other EDBs. Aurora Energy assesses the health of the fleet by using a similar manner to that is recommended by the “EEA’s Asset Health Indicator Guide”. The AHI is generated using a weighted average of six separate condition indicators, the two highest weightings being asset age and oil tests (DP/Furans). Degree of Polymerisation (DP) provides a strong indication of actual remaining life and it is industry practice to place confidence in these test results rather than the nameplate age of the transformer to assess the condition of the transformer core.

Using this analysis, each transformer is designated H1 to H5 health scores which should be used as a proxy to the probability of failure in more advanced asset health models. Aurora Energy has instead used a consistent approach to the other asset classes by designating expected remaining life to the definition of health indices. This definition of each asset health level differs somewhat from the EEA’s Asset Health Indicator Guide which is defined by assessment of condition only. For age-based renewal models, Aurora Energy’s approach is effective. Following discussions with Aurora Energy staff, it was acknowledged that the method in which insulation paper condition (DP) was mapped into the health indices in the Aurora Energy model was different to the EEA Asset Health Indicator Guide and that this will be corrected in updates to the model. As detailed in section D.8.7, this has however not resulted in the need to correct forecasts for the CPP or review periods.

Segregation into subpopulations is not relevant when asset condition can be based on individual assets and frequent sampling. The model could be further advanced in the future to include separate models for tap changers and bushings which are key failure modes for power transformers.

The WSP 2018 report summarised the overall condition of power transformers and identified several cases where tap changers had not been maintained to manufacturer’s recommendations. The poor condition of tap changers appears several times in condition assessments for Aurora Energy transformers in the renewal model. There were eight transformers identified by WSP as high risk to reliability based on internal condition and tap changers. Overall, WSP assessed the risks for power transformers as moderate to network reliability and low risk to public safety.

### D.8.6 Consequence of failure and risk modelling

#### Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure

Failure modes of transformer are generally well known which is used to drive maintenance strategy to prevent failures. Failure modes are also used to define the key condition indicators which will assist in predicting future failure probability. Aurora Energy has used the key parameters in its approach to weighting to arrive at a composite health index.

Aurora Energy has further developed this risk-based model by assigning a criticality index that ranges from one to five (i.e. C1 through C5) to each transformer using a weighted average of the following factors (approximating VoLL at risk):

- magnitude of the load supplied
- security afforded to the zone substation (i.e. N vs N-1 vs N-1 switched)
- type of load supplied (i.e. CBD vs urban vs rural)
- load transfer capability (i.e. the backup 11 kV supply from the adjacent substations).

Other considerations are being made outside of the model with regard to increasing resilience to seismic events and progressively installing oil containment as part of the renewal program to reduce environmental risks and ensure compliance with regulations.

### **Risk assessment methodology**

To forecast zone substation portfolio expenditure, the renewal models for power transformers (and indoor switchgear and outdoor switchgear) are informed by AHIs and asset criticality. This both identifies and assists in prioritising the replacement of the equipment.

The combination of AHI and criticality defines a risk matrix whereby assets can be tracked as their condition worsens and the model is able to predict when they will enter the intolerable sector of the matrix. The 'intolerable sector' is based on a number of factors, including:

- proactively replacing transformers that have reached an AHI=H1
- for critical transformers with a C1 score, the transformer is considered for replacement when it reaches H2.

Aurora Energy has confirmed that to the extent practical, the AHI and criticality risk model comply with Aurora Energy's corporate risk matrix, including the definition of intolerable risk between the two matrices. We agree that the matrices are well aligned.

## **D.8.7 Asset strategy and renewals model**

### **Asset strategy**

POD08 can be viewed as the asset management plan for this fleet along with the AMP 2018-2028. The renewal model is a risk-based model as described above which considers both condition, nameplate age and criticality factors. This is consistent with good industry practice for power transformers.

The key preventive maintenance tasks for zone substation assets are provided in the AMP 2018-2028 with weekly, monthly and annual task intervals defined. The maintenance tasks and intervals are consistent with industry practice.

### **Options and data inputs**

The data inputs for the renewals model uses condition based and age data along with the assessment of criticality based on the reliability required of each transformer. The high quality of the inputs should be expected to produce reliable replacement forecasts; however, we identified a misinterpretation with the use of condition data and the mapping of that data into remaining life. This is bringing forward the required timing of transformer replacements.

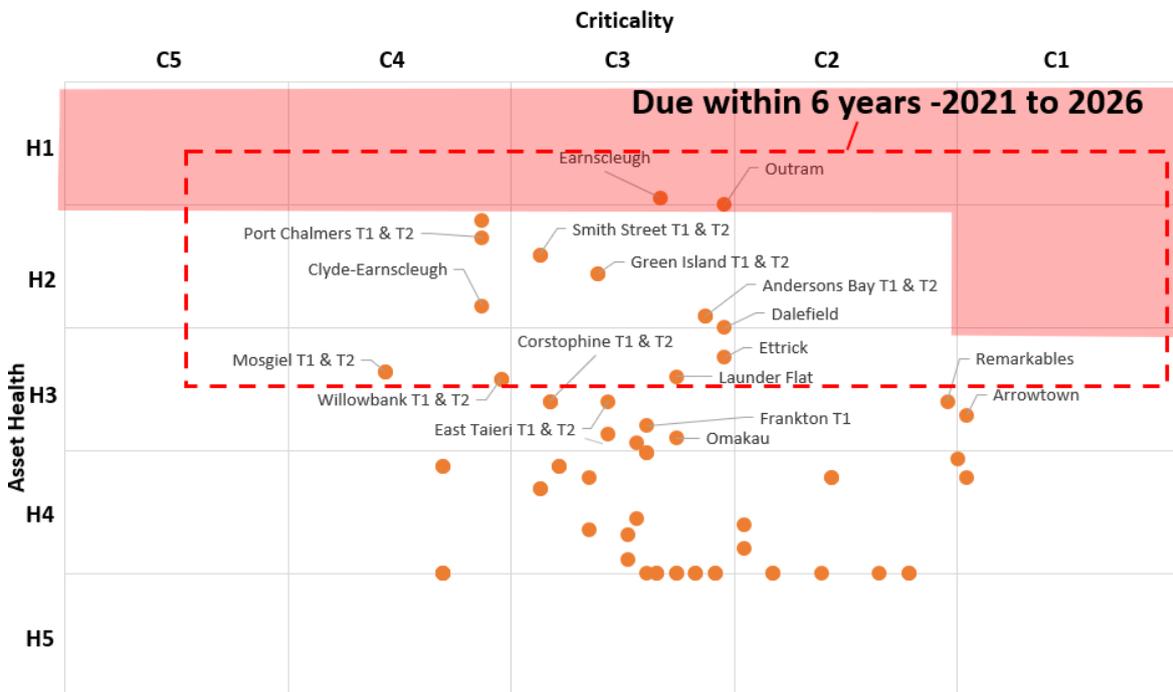
This arose from how DP was interpreted from the EEA guideline and mapped into the five asset health indices. DP measurements in transformers quickly reduce (starting at around 800–1000) in the first one third of life (down to around 500) then more slowly decreases over the next one third (to around 350),

then over the remaining 20 years reduces more gradually to levels considered to be end of life (around 200). Aurora Energy has inadvertently used the example mapping in the guideline without adjustment understates the remaining life in our view.

We also consider the weighting for DP and other oil testing results should be higher within the model compared to nameplate age but do recognise that other condition, performance and network dependency can drive actual replacement priority.

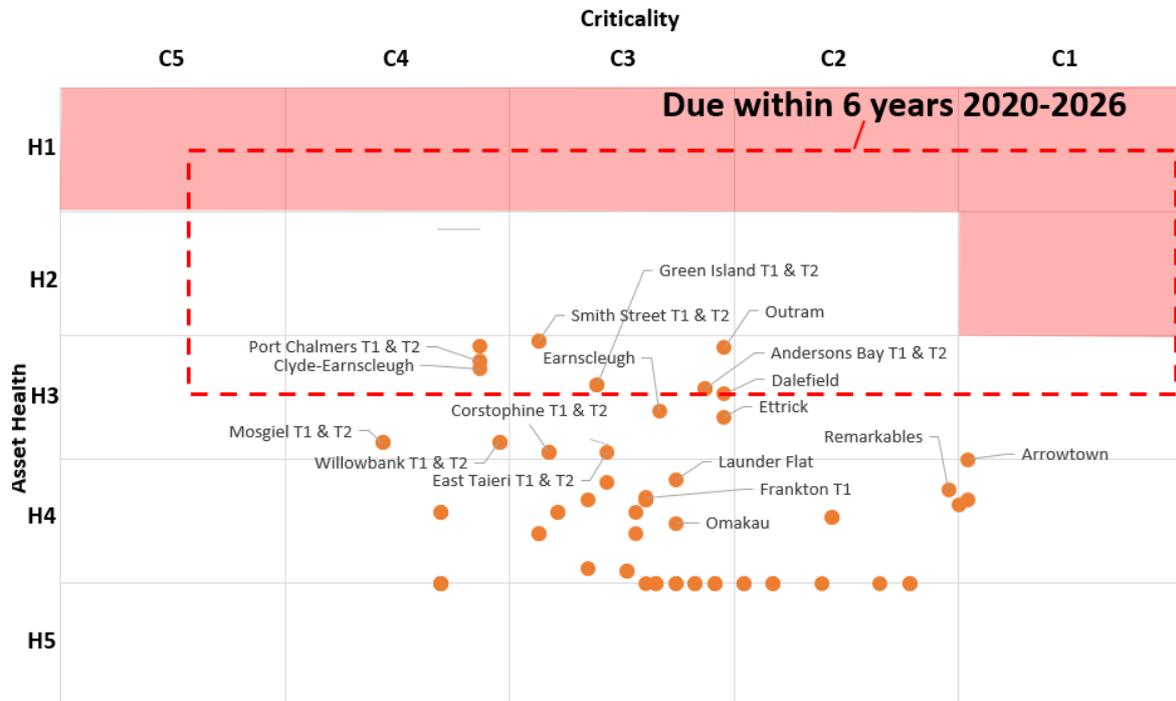
After we made changes in the model, Figure D.7 and Figure D.8 below demonstrate the difference in forecast transformer replacement over the review period.

Figure D.7: Power transformer replacements over the review period (Aurora Energy data mapping)



Source: Aurora Energy, MOD09a - Power Transformers risk model.xlsx (unadjusted)

Figure D.8: Power transformer replacements over the review period (adjusted mapping)



Source: MOD09a - Power Transformers risk model.xlsx (adjusted)

Aurora Energy’s modelling flagged 19 transformers over the period to RY26 needing to be replaced; however, in the coordination of zone substation projects this was reduced to 11 transformers over the review period (POD08 stated 12 however Aurora Energy has corrected this to 11 replaced and one decommissioned). The other eight transformers were deferred beyond RY26.

Aurora Energy’s adjusted coordination model is forecasting coincidentally 11 power transformers requiring replacement prior to the end of the CPP and review periods in RY26. Hence it is unlikely that any of these 11 transformers planned for replacement in the review period can be deferred, hence we agree with the CPP forecast transformer replacements quantity. This finding has been acknowledged by Aurora Energy and we expect that the renewal model will be revised.

The actual transformers selected for replacement by Aurora Energy in the CPP period does not match entirely with the order of merit identified in the revised model. The following four transformers were discrepancies identified in the adjusted model based on condition and criticality (two transformers have been brought forward into the CPP period):

- Earnsclough – this substation is being decommissioned in RY22 for multiple reasons and therefore the transformer model is less relevant to the decision to decommission
- Launder Flat – Aurora Energy appears to have included this replacement due to single transformer supply concerns in RY25/26
- Arrowtown – the inclusion of these two smaller transformers, treated as one, is based on non-compliant reasons and overall project site refurbishment in RY24/25
- Omakau – work at this substation is growth related and due to COVID-19 has been deferred from RY22 to RY24.

The Smith Street T1 and T2 transformers were flagged as needing replacement in the CPP period, but were chosen to be deferred by Aurora Energy following detailed review of condition and lower risk of failure with capacity available through network interconnections.

The modified transformer replacement forecast is the same number as predicted by the adjusted model, which means that the forecast expenditure is not affected.

### **Data outputs and replacement forecast**

Aurora Energy used a separate coordination tool to review the entire portfolio of asset replacements in the zone substation portfolio to develop optimised project timing.

As identified early in this section, Aurora Energy's renewal model identified 19 transformers over the period to RY26 needing replacement; however, in the coordination model this number was reduced to 11 transformers over the review period. The other eight transformers flagged over the period for replacement were deferred beyond RY26 in the coordination model.

### **Validate model outputs**

We have reviewed the risk-based renewal model and the coordination model and we accept that the models are valid but do not accept that the data inputs have been correctly applied in the renewal model resulting in a higher forecast of required transformer replacements over the review period.

The coordination process and model reduced this number to 11 which is 17% of the total fleet over the review period. In comparison with two Australian distributors their replacement rates are 6.5% and 10.5% over the same period. The volume of 11 transformers planned is reasonable considering Aurora Energy has not had a proactive replacement strategy in place prior to now and the replacements are based on condition and consequence of failure to determine priorities.

## **D.8.8 Our findings**

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of:

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's power transformer renewal program over the CPP and review periods are that:

- We agree with the use of the risk-based renewal model to forecast the timing need of transformer replacements and the coordination approach to bundle work into specific zone substation projects.
- We found the renewal model design to be valid, however, the mapping of input data for use in the model forecasted earlier timing for replacements than justified. The renewal model forecasted 19 transformer replacements to RY26 whereas our adjusted model forecasted 11. This number aligns with the Aurora Energy's proposed number of replacements following the project coordination process.
- There were some discrepancies in the priority of transformers selected by Aurora Energy for replacement over the review period compared with our adjusted model. Discussions with Aurora Energy clarified the reasons for the priorities based on reasonable risk and other priority considerations.

Based on our assessment of the CPP proposal and supporting material, the forecast modelling approach and forecasts for the power transformer replacement appear consistent with the expenditure objective over the CPP and review periods.

This assessment supports respective findings detailed in sections C.8.5 (Assessment of forecast method used), C.8.5.2 (Expenditure Justification) and C.8.5.6 (Interaction with other forecast expenditures).

## D.9 INDOOR SWITCHGEAR RENEWALS (R5.1)

### D.9.1 Information provided

Table D.16 presents the information that has been provided by Aurora Energy specifically relevant to indoor switchgear.

The zone substation portfolio contains a total of 339 indoor circuit breakers (contained on 30 switchboards) and at three different voltages 6.6 kV, 11 kV and 33 kV.

Table D.16: Information provided

Title	Reference	Date
POD09 – Zone Substation	E-38	28 February 2020
P11 – Renewals – Zone Subs & Protection	V-99	26 March 2020
MOD09b - Indoor Switchgear risk model.xlsx	V-106	26 March 2020
MOD09 – Zone Substation Coordination Model	E-37	28 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-FM15-W01 - Zone Substation Maintenance	IPC-1332	24 December 2019
Zone substation cost estimates (customised cost estimate build-up of 14 renewal projects)   MOD09-01 to MOD09-10, 13, 19, 22 and 26	E-40 to E-53	28 February 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FA15-F01 - Technician Check Sheet	IPC-1057	29 November 2019
AE-FA05-F01 - Vacuum Circuit Breaker - Indoor Test Form	IPC-1071	29 November 2019
AE-FA05-F03 - SF6 Circuit Breaker - Indoor Test Form	IPC-1069	29 November 2019
AE-FA05-F05 - Oil Circuit Breaker - Indoor Test Form	IPC-1066	29 November 2019
AE-FA05-F08 - Zone Substation LV Bus Bar Test	IPC-1068	29 November 2019
AE-FA05-F10 - Indoor Switchboard Maintenance Check List	IPC-1061	29 November 2019
AE-FM05-F02 - Oil Filled Switchgear (RMU) Maintenance	IPC-1046	29 November 2019
AE-FR01-F02 - Switchgear Installation	IPC-1041	29 November 2019

Title	Reference	Date
RFIs D001-D027, DD139 and D352	RFI responses set out in Table I.2	Late March, early April 2020
<b>Provided in response to our draft report</b>		
Notes regarding updated MOD09	PR-3	21 April 2020
MOD09 - Zone Substation Coordination Model - Post IV review	PR-2	21 April 2020
Notes regarding Updated MOD09 - Zone Substations Coordination model	PR-3	21 April 2020

## D.9.2 Data and integrity

### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report which found data quality gaps requiring some validation. WSP found that the data held by Aurora Energy for circuit breakers was generally quite good. Two key data sources were the GIS and the maintenance schedule spreadsheet. Attribute data was missing in about 10% of cases.

We expect Aurora Energy has updated this information into the GIS database since the WSP report. The number of operations and condition is well documented although recorded using site inspection sheets. This can electronically be recorded in an EAM systems when implemented by Aurora Energy.

### Data quality

WSP considered that the asset attribute data for the indoor switchgear fleet was of good quality including condition and performance data. Some areas did require validation and correction during the preparation of the asset plan and forecast. The model does not use condition data directly to determine asset health index ratings and uses only age for this purpose for which the quality of data is good.

## D.9.3 Asset population and age profile

### Asset population by age

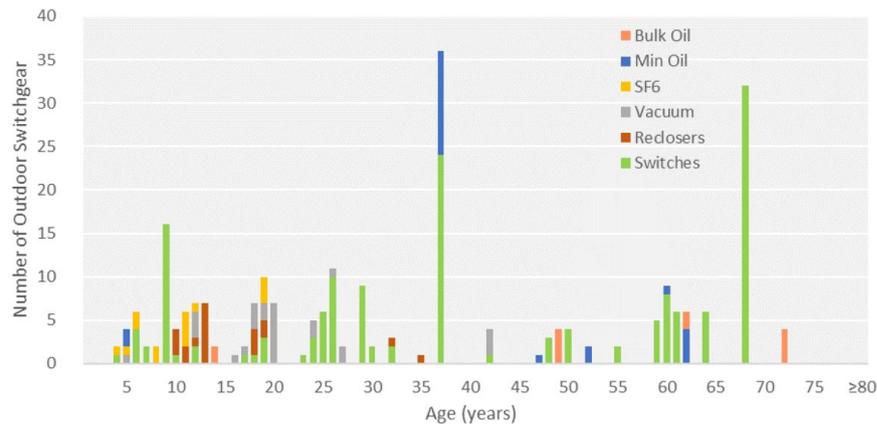
The zone substation portfolio contains a total of 339 indoor circuit breakers (switchgear contained within switchboards) with an average age of 33 years, with those in the Dunedin region having a significantly higher average age than those in the Central region. A significant number of the oil circuit breakers have exceeded their expected life, with the average age of oil circuit breakers currently at 55 years.

Many of these aged circuit breakers are located in the Dunedin region. In contrast, the vacuum and SF<sub>6</sub> circuit breakers are relatively young with average ages of 11 years and 27 years, respectively.

The quantities at the different voltage levels ratings are:

- 6.6 kV (61 units)
- 11 kV (269 units)
- 33 kV (9 units).

Figure D.9: Indoor switchgear age profile



Source: Aurora Energy, POD08 – Portfolio Overview Document | Zone substations

### Expected life

Aurora Energy has designated the life expectancy for vacuum and SF6 circuit breakers to be 45 years. For bulk oil and minimum oil circuit breakers life expectancies is designated to be 50 and 35 years, respectively.

Comparing quoted expected lives by Australian and New Zealand businesses indicate expected lives of 45 to 50 years, with vacuum circuit breakers less at around 35 years. Bulk oil circuit breaker switchboards range from 50 to 65 years. The longer time frames would equate to the few still in service to this age. These are consistent with Aurora Energy’s defined asset expected lives.

## D.9.4 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

There are no performance objective or targets set for indoor switchgear. Arc flashes are the most serious failure mode for switchgear but are rare and not suitable as an indicator. Aurora Energy could consider other indicators of deteriorating condition to component failure performance to set objectives where they can relate to the relevant reliability and safety risks.

RIN data available for circuit breaker failures in Australia shows that five failures per 1000 units/year could be an appropriate measure and target. Some Australian distributors are experiencing more than 10 failures on average. With 339 circuit breakers, Aurora Energy’s target would be less than two failures per annum.

### Past performance and forecast performance

Aurora Energy states that its understanding of the past performance of its indoor switchgear is limited by the available data and plan to improve the capture and analysis of fault and defect data to support ongoing performance monitoring.

The WSP review identified several outages attributed to circuit breaker failures, and that outage frequency was increasing over time. The WSP review also noted the prevalence of indoor oil insulated circuit breakers involved in outages, and that the causes were generally attributed to equipment deterioration.

The WSP review found around five incidents of circuit breakers failing to operate and clear faults from 2015 to 2018. Further analysis into the cause of the failures showed that 42% were attributed to asset deterioration and a further 46% were attributed to human error. The failure rate performance therefore is

at least two per annum due to the deterioration of the assets. Aurora Energy expect the failure rate to worsen.

Aurora Energy has not recorded any arc fault failures on the network, however, this is a low probability but an extremely high consequential risk. Aurora Energy is addressing the known risks through the replacements planned.

We agree with the general outlook that with no indoor switchgear renewal, the performance of the switchgear would continue to decline and the risks of arc flashes would be unacceptable.

### D.9.5 Asset condition and modelling

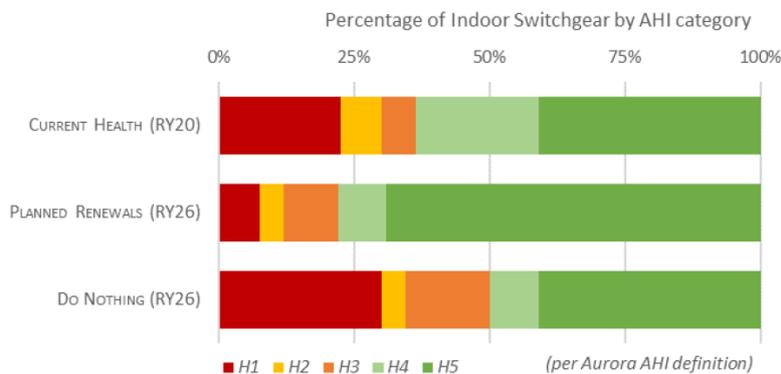
#### Asset health / condition and asset subpopulations

Aurora Energy does not have reliable condition information for the indoor switchgear to be used as inputs to the model to determine the replacement timing to manage safety risks. An examination of existing circuit breaker condition information alone is not useful for predicting end-of-life in a systematic model.

Equipment age instead has been used as the best available proxy for switchgear condition/health and thus the AHI for indoor circuit breakers is based on remaining life, calculated by subtracting age from indoor switchgear life expectancy. We consider this a reasonable approach given the difficulties in assessing potential future failure, which is consistent with industry experience.

Figure D.10 indicates an increasing percentage would exceed expected life if the planned renewals did not proceed. Statistically a percentage above the mean is valid to remain within an accepted risk tolerance and based on information available on mean life for replacements, this is typically 10% to 15% above the mean. Aurora Energy is aiming to reduce the percentage AHI1 to 8% by end of RY26. This may suggest the forecast quantity is conservative. We note that Powerco is aiming to consistently operate near zero above the expected life of its assets (between 45 and 50 years) based on arc fault risk, hence Aurora’s Energy’s risk position is higher than Powerco.

Figure D.10: Indoor switchgear asset health



Source: Aurora Energy, POD08 – Portfolio Overview Document | Zone substations

The indoor switchgear fleet is segmented by insulation type and circuit breaker interruption medium which is industry practice.

### D.9.6 Consequence of failure and risk modelling

#### Failure modes and consequences (safety, reliability, quality, other)

The circuit breaker replacements are aimed to reduce worker safety risks and performance risks as identified in POD08.

While failure modes are understood it is difficult to use test data for replacement forecasting as discussed. Aurora Energy has developed a model that allows engineering judgement on risk parameters such as the type of protection for clearing arc faults, the availability of spares, switchgear fault rating and VoLL at risk.

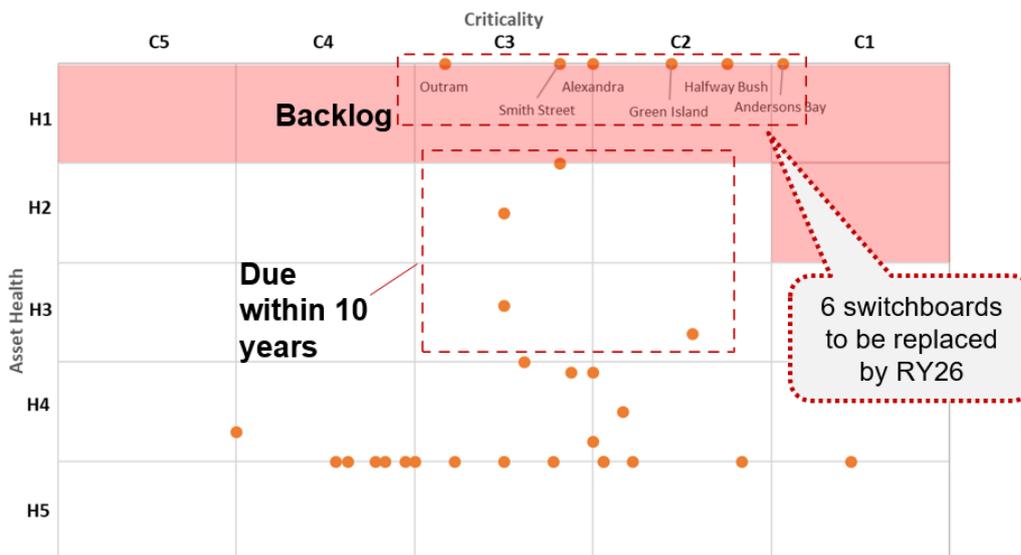
#### Risk assessment methodology

The risk methodology incorporated in the renewal model considers the consequence of failure and the ability of the switchgear and protection systems to minimise risk to workers. The methodology is used to prioritise replacements but is unable to optimise the specific time based on condition as discussed, instead based on maintaining the percentage of assets with an AH1 to an acceptable level.

To prioritise indoor switchboard replacements, the model assigns switchboards a criticality index that ranges from one to five (i.e. C1 through C5). The criticality indices are determined using a weighted of the failure consequences listed above. Assets with an AH1 for all criticality levels and AH2 for criticality C1 are considered to be in unacceptable risk zones.

We consider this is a reasonable approach to prioritise replacement order based on assessed risks and the timing consistent with industry practice based on age.

Figure D.11: Output from the indoor switchgear risk model



Source: P11– Renewals - Zone Substation and Protection

## D.9.7 Asset strategy and renewals model

### Asset strategy

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish the 2018-28 AMP. POD08 can be viewed as the asset management plan for this fleet.

The asset strategy is to replace the switchgear once it has reached its expected life with priority based on an engineering-based assessment of risks.

As detailed in the AMP 2018-2028, maintenance includes routine monthly visual inspections, annual thermal imaging, operational checks and four yearly overhauls of oil circuit breakers.

The above asset strategy is consistent with industry practice for this asset fleet.

### Options and data inputs

Options regarding the specific replacement timing options for indoor switchgear is considered during the overall coordination and bundling of work into the specific zone substation projects (refer our review in section D.7.8).

We consider that the data inputs used in the model is reasonable noting that arc fault protection type is given the same weighting as reliability measures of load at risk and back up supply.

### Data outputs and replacement forecast

Aurora Energy has used its separate tool to review the entire portfolio of asset replacements in considering the actual indoor switchboards flagged for replacement and then included for replacement over the 10-year planning period.

Aurora Energy planned to replace six of the indoor circuit switchboards (88 circuit breakers) from RY21 to RY26. The switchboard for Outram is scheduled for replacement in RY21. Of the six switchboards identified as AH1, Smith Street 11 kV switchboard was initially deferred beyond the review period and South City 11 kV switchboard included in the program over this period.

Following discussion with Aurora Energy, the coordination model was updated as follows (as per 'Notes regarding updated MOD09'):

- the risk/need to replace the South City 11 kV Switchboard has been deferred from RY25 to RY30
- Smith Street 11 kV switchboard replacement can be brought forward 2 years to achieve RY24 commissioning.

The unit costs for the indoor switchgear replacement have been applied correctly. Our assessment of the efficiency of unit costs and deliverability is set out in Appendix C for all the programs.

### Validate model outputs

Aurora Energy did not complete any sensitivity analysis for the assumptions in the input data. However, given the methodology adopted by Aurora Energy and the input data it relied on we do not consider such analysis to be necessary.

We compared the replacement rates against Powerco with 16.5% of its switchboards planned to be replaced over the next five year period compared to Aurora Energy which is forecasting six replacements over the five year review period out of its population of 30 switchboards (or 20%). Two Australian

distributors plan to replace 8% and 15% respectively over the next five years, and both having had replacement programs in place in previous years.

Based on the risk assessment approach we can validate those switchboards assessed with an AHI of 1 criticality to be replaced.

### **D.9.8 Our findings**

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of:

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's indoor switchgear renewal program over the CPP and review periods are that:

- We agree with the use of the risk-based model to forecast the timing need for indoor switchgear replacements and the coordination approach to bundle work into specific zone substation projects.
- We found the renewal model design to be valid noting the limitation that asset health is based on age compared to expected life and the limitation of using test results to estimate probability of failure.
- The quantities planned for replacement in the CPP and review periods is consistent with the age of the assets and the replacement rates of peers in the industry.

The expenditure forecast for the indoor switchgear replacement over the CPP and review periods appears consistent with the expenditure objective. To form this view we assessed the CPP proposal, supporting material and discussed these with Aurora Energy staff, including on the adjustments to the Smith Street and South City indoor switchboards.

This assessment supports respective findings detailed in sections C.9.5 (Assessment of forecast method used), C.9.5.2 (Expenditure Justification) and C.9.5.6 (Interaction with other forecast expenditures).

## D.10 OUTDOOR SWITCHGEAR RENEWALS (R5.3)

### D.10.1 Information provided

Table D.17 presents the information that has been provided by Aurora Energy specifically relevant to outdoor switchgear.

Aurora Energy has a portfolio of 249 outdoor circuit breakers and switches located within zone substations.

Table D.17: Information provided

Title	Reference	Date
POD09 – Zone Substation	E-38	27 February 2020
P11 – Renewals – Zone Subs & Protection	V-99	26 March 2020
MOD09c - Outdoor Switchgear risk model.xlsx	MOD: 09c	27 February 2020
MOD09 – Zone Substation Coordination Model	E-37	28 February 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-FM15-W01 - Zone Substation Maintenance	IPC-1332	24 December 2019
Zone substation cost estimates (customised cost estimate build-up of 14 renewal projects)   MOD09-01 to MOD09-10, 13, 19, 22 and 26	E-40 to E-53	28 February 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
191218 ISO 55001 summary	C-1326	20 December 2019
191218 Risk Summary slides for Tripartite meeting 19 December	C-1327	20 December 2019
AE-FA15-F01 - Technician Check Sheet	IPC-1057	29 November 2019
AE-FA05-F02 - Vacuum Circuit Breaker - Outdoor Test Form	IPC-1070	29 November 2019
AE-FA05-F04 - SF <sub>6</sub> Circuit Breaker - Outdoor Test Form	IPC-1067	29 November 2019
AE-FA05-F06 - Oil Circuit Breaker - Outdoor Test Form	IPC-1065	29 November 2019
AE-FA05-F07 - Recloser - Outdoor Test Form	IPC-1064	29 November 2019
AE-FA05-F09 - Recloser Annual Inspection	IPC-1063	29 November 2019
AE-FA17-F01 - Current Transformer Test Form	IP-1235	12 December 2019
AE-FA17-F06 - Voltage Transformer Test Form	IPC-1050	29 November 2019

Title	Reference	Date
AE-FR01-F02 - Switchgear Installation	IPC-1041	29 November 2019
RFIs D001-D027, DD139 and D352	RFI responses set out in Table I.2	Late March, early April 2020
<b>Provided in response to our draft report</b>		
MOD09 - Zone Substation Coordination Model - Post IV review	PR-2	21 April 2020
Notes regarding Updated MOD09 - Zone Substations Coordination model	PR-3	21 April 2020

## D.10.2 Data and integrity

### Definition of asset data and register

The asset data availability of this fleet was assessed by WSP in its 2018 report which found data quality gaps requiring some validation. WSP found that the data held by Aurora Energy for circuit breakers was generally quite good. Two key data sources were the GIS and the maintenance schedule spreadsheet.

### Data quality

WSP in its infrastructure report considered the asset attribute data for the outdoor switchgear fleet was of good quality including condition and performance data. Some areas have required validation and correction during the preparation of the asset plan and forecast. The model does not use condition data directly to determine asset health index ratings and uses only age for this purpose for which the quality of data is good.

## D.10.3 Asset Population and Age Profile

### Asset population by age

Aurora Energy's zone substation portfolio contains a total of 249 outdoor switchgear units, comprising:

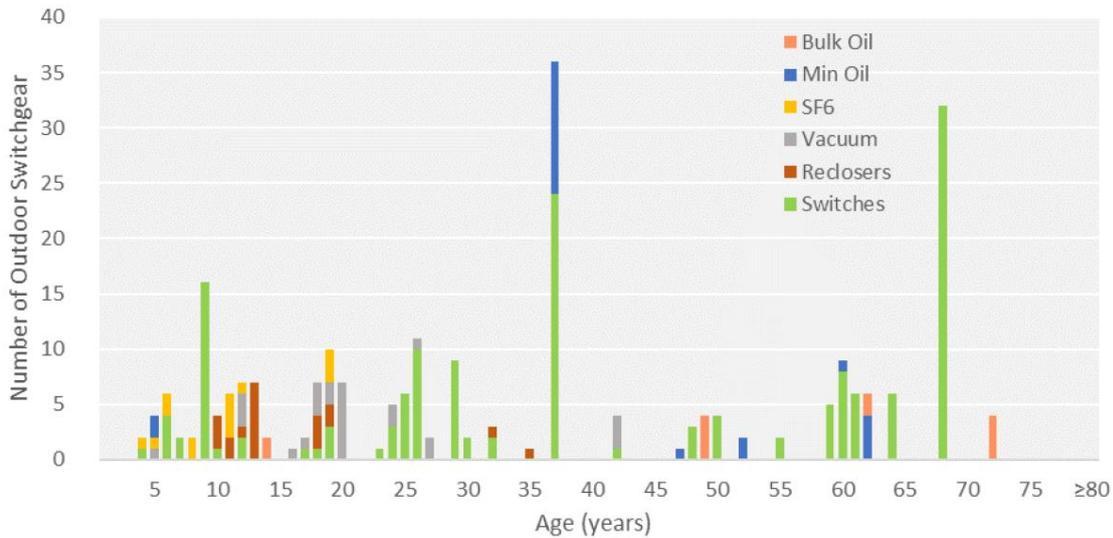
- circuit breakers (74 units)
- reclosers (20 units)
- switches (155 units).

The majority of outdoor circuit breakers installed prior to the 1990s are oil insulated (28 units). The remaining outdoor circuit breakers (generally installed post 1990) are vacuum insulated (32 units) or SF6 insulated (14 units).

Figure D.12 shows the age profile of outdoor switchgear by type. The average age of the outdoor circuit breakers (Bulk Oil, Min Oil, SF6 and Vacuum) is 27 years, with those in the Dunedin region having a significantly higher average age than those in the Central region.

Figure D.12 illustrates that a significant number of the switches have exceeded a life expectancy of 45 years.

Figure D.12: Outdoor switchgear age profile



Source: Aurora Energy, POD08 – Portfolio Overview Document | Zone Substations

### Expected life

The life expectancy of Aurora Energy’s outdoor vacuum and SF6 circuit breakers are 45 years. The bulk oil and minimum oil insulated circuit breakers have respective life expectancies of 50 and 35 years. A number of the oil circuit breakers have already exceeded their life expectancy.

Comparing quoted expected lives by Australian and New Zealand businesses indicate expected lives of SF<sub>6</sub> outdoor breakers to 45 to 50 years and oil type range from 50 to 65 years (bulk oil). This is consistent with Aurora Energy’s expected lives.

## D.10.4 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

There are no performance objective or targets set for outdoor switchgear. Aurora Energy should consider indicators of deteriorating performance to set performance objectives where they can relate to the relevant reliability and safety risks. The industry available data on circuit breakers failures could have been used to define interim targets for outdoor switchgear.

### Past performance and forecast performance

Aurora Energy’s understanding of the performance of outdoor switchgear is similar to that for indoor switchgear and limited by the available data. It is planned to improve the capture and analysis of fault and defect data to support ongoing performance monitoring.

The ageing population of oil filled outdoor switchgear poses safety and performance risks. There are a number of indoor minimum oil filled circuit breakers (ABB type HKK) that have been installed in locally made, poorly designed, outdoor cubicles in the switchyards. A number of EDBs have experienced issues with these circuit breakers, primarily due to water ingress and internal pollution leading to flash overs. WSP’s review specifically identified the risks and hazards associated with this switchgear type. Two recent experiences of this switchgear failing resulted in a switchyard fire in one case and oil expelled in a second failure event.

Other type issues include fourteen 33 kV type circuit breakers that are vacuum bottles immersed in oil with the possibility of fire if they fail, and eight 33 kV minimum oil circuit breakers that are not maintained due to a lack of spare parts and manufacturer support.

We agree with the general outlook that the outdoor switchgear fleet has several different type issues which require replacements.

### D.10.5 Asset condition and modelling

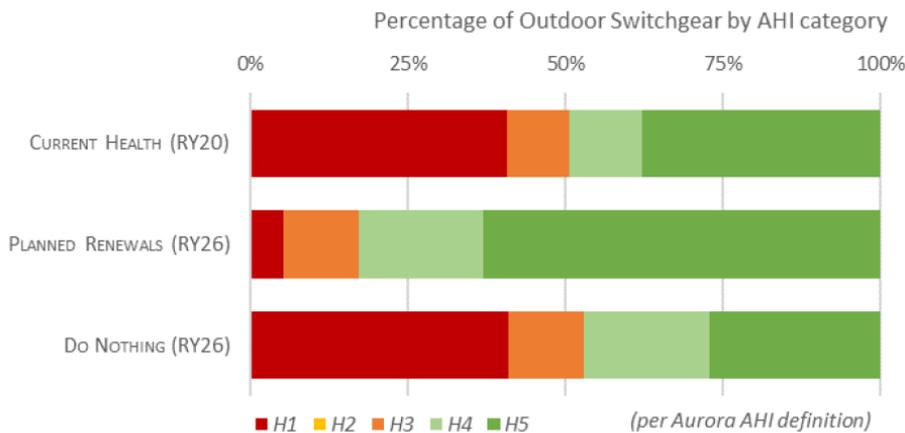
#### Asset health / condition and asset subpopulations

There is insufficient quality of condition data for outdoor circuit breakers and air break switches to systematically translate to AHI. The AHI model for outdoor switchgear is based on expected remaining life, calculated by subtracting the current age of each circuit breaker, recloser or switch from its life expectancy. Equipment age is assumed to provide a reasonable proxy for switchgear condition/health.

The outdoor switchgear fleet is segmented by insulation type.

Based on this modelling approach the current health is in a poor overall state with over 30% with an AH1 rating. The model is forecasting the immediate replacement of nearly all of the outdoor assets with an AH1 rating as Figure D.13 does not change the number of assets with AH1 in the do-nothing scenario over the review period.

Figure D.13: Indoor switchgear asset health



Source: Aurora Energy, POD08 – Portfolio Overview Document | Zone substations

### D.10.6 Consequence of failure and risk modelling

#### Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure

There is a significant number of safety and reliability related risks with the failure of outdoor switchgear. Bulk oil circuit breakers can fail catastrophically involving arc flashes and oil ignition. Other consequences include substation fires and collateral damage to other substation plant.

Failure of circuit breakers to clear faults will result in outages until alternate supplies can be switched and re-energised. Air break switch failures can prevent maintenance works to be undertaken and isolation of feeders extending outage durations.

### **Risk assessment methodology**

The model does not include the development of criticality indices. Most planned renewals are done in conjunction with power transformer or indoor switchgear projects and driven by the criticality of these assets. Therefore, outdoor switchgear inherits criticality from either indoor switchgear or the power transformer renewals model. However, Aurora Energy does intend to develop a criticality framework in the future.

The output from the age-based renewal model identifies required timing for the renewal of the outdoor circuit breakers which can then be considered along with transformer and indoor switchgear replacements.

The approach includes the ability to modify the timing of the switchgear renewals based on the output of the coordination tool that is also used to optimise renewal and growth projects with the objective of managing resourcing levels and aligning projects occurring at the same substation (and within a similar time-frame).

### **D.10.7 Asset strategy and renewals model**

#### **Asset strategy**

At this point in its asset management maturity journey, Aurora Energy has accepted the findings of the WSP report and has utilised the detail of that review to establish the 2018-28 AMP. POD08 can be viewed as the asset management plan for this outdoor fleet.

The asset strategy is to replace the switchgear once it has reached its expected life with priority based on the coordination with other replacement work within zone substations.

As detailed in the AMP 2018-2028, maintenance includes routine monthly visual inspections, annual thermal imaging, operational checks and four yearly overhauls of oil circuit breakers.

The above asset strategy is consistent with industry practice for this asset fleet.

#### **Options and data inputs**

Options regarding the specific replacement options for outdoor switchgear is considered during the overall coordination and bundling of work into the specific zone substation projects (refer to our review in section D.7.8). The Do-Nothing option has been modelled in terms of understanding the increase in the poor health of the assets.

The data inputs used in the renewal model is based entirely on nameplate age and expected life of switchgear types.

#### **Data outputs and replacement forecast**

Aurora Energy has used its separate tool to review the entire portfolio of asset replacements in considering the actual the outdoor switchgear that have been flagged for replacement to be included for replacement over a 10 year planning period.

The unit cost replacement for indoor switchgear have been applied correctly. We have addressed assessment of the efficiency of unit costs and deliverability in Appendix D for all the programs.

### Validate model outputs

Aurora Energy did not complete any sensitivity analysis for the assumptions in the input data. However, given the methodology adopted by Aurora Energy and the input data used, we do not consider that sensitivity analysis is necessary.

Over the period RY21 through RY30 Aurora Energy plans to replace outdoor switchgear at 14 zone substations, while during the review period it plans to replace equipment at nine locations.

In total the plan is to replace 35 switches (23%) and 26 circuit breakers/reclosers (28%) over the review period.

We compared the replacement rates against Powerco with 19% of its circuit breakers planned to be replaced over the next five-year period. Two Australian distributors plan to replace 8% and 15% respectively over the next five years (covering both indoor and outdoor switchgear). Both businesses have had replacement programs in place in previous years.

Based on the approach we can validate the requirement to replace the forecast quantities of outdoor switchgear all assessed with an AH1 index. The switchgear also coincides with the requirement to replace transformers and indoor switchgear at the specific zone substation project sites.

### D.10.8 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of:

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's outdoor switchgear renewal program over the CPP and review periods are that:

- we agree with the use of the asset renewal model forecasts, the timing need for outdoor switchgear replacements and the use of the coordination approach to bundle work into specific zone substation projects
- we found the renewal model design to be valid noting the limitation that asset health is based on age compared to expected life and the limitation of being able to use test results to estimate probability of failure
- the quantities planned for replacement in the CPP period and the review period is consistent with the current older age of the assets requiring higher replacement rate compared to peers in the industry.

Based on our assessment of the CPP proposal and supporting material, the forecasts for the outdoor switchgear replacements over the CPP and review periods appear consistent with the expenditure objective.

This assessment supports respective findings detailed in section C.10.5 (Assessment of forecast method used), C.10.5.2 (Expenditure Justification) and C.10.5.6 (Interaction with other forecast expenditures).

## D.11 LV ENCLOSURES RENEWAL (R6)

### D.11.1 Information provided

Table D.18 presents the information that has been provided by Aurora Energy relevant to LV enclosure replacement expenditure modelling and the associated asset strategy of this fleet.

Table D.18: Information provided

Title	Reference	Date
MOD18 – LV Enclosures	E-7	21 February 2020
POD18 – LV Enclosures	E-8	21 February 2020
P07 - Renewals - LV Enclosures	V-82	25 March 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
AE-Policy-01 - Health and Safety	IPC-981	29 November 2019
Aurora-Energy-2018-AMP-UPDATED for 2019	IP-1246	12 December 2019
D012 – Link Enclosure Inspection Data	V-84	25 March 2020
D012 – Link Enclosure Inspection Data_1	V-84	25 March 2020
D012 – Link Enclosure Inspection Data_2	V-84	25 March 2020
D012 – Link Enclosure Inspection Data_3	V-84	25 March 2020
RFIs D001-D027, DD139 and D352	RFI responses set out in Table I.2	Late March, Early April 2020
D014 – LV enclosure unknown age prorate calc.xlsx	V-4	12 March 2020
<b>Provided in response to our draft report</b>		
MOD18 – LV Enclosures – Post IV Review	PR-10	23 April 2020

### D.11.2 Other information relied on

Table D.19 sets out the other information that we relied on when reviewing Aurora Energy’s LV enclosure replacement expenditure.

Table D.19: Other information relied on

Title	Author	Date
2018 Asset Management Plan	Top Energy	27 March 2018
2018 Asset Management Plan	WEL Networks	29 March 2018

Title	Author	Date
Electricity Asset Management Plan 2019	Powerco	2019
Independent Review of Electricity Networks	WSP	21 November 2018

### D.11.3 Data and integrity

#### Definition of asset data and register

The asset data availability of this fleet was discussed in POD18. The current key source for this asset fleet attributes is the ArcFM/ArcGIS database. There was reasonable data on age and location, but little asset condition information initially available because there had not been any dedicated inspection or testing program in the past. A dedicated inspection program has been implemented in 2020 and now 49% of the assets (based on the inspection data sets) have had data collected during these inspections.

Aurora Energy advised us at the PO7 workshop in March 2020 that originally only 3,500 LV enclosures had age defined, but with a further 4,800 inspected the age very closely aligns with the original age profile.

#### Data quality

In POD18, Aurora Energy stated that the asset attribute data for this fleet had been of poor quality, condition and performance data non-existent. However, the data provided from inspections over the last few months provided comprehensive data on 10,355 enclosures out of the total of around 21,000 units (49%) – meaning that that data can now be used to draw suitable conclusions about the age and condition of Aurora Energy’s LV enclosure fleet.

To address the 23% of the LV enclosures asset population with unknown age profile, Aurora Energy extrapolated or scaled up the age profile of the known population of LV enclosures to establish an age profile for the entire fleet. This is commonly practiced approach in such instances in the industry.

Aurora Energy has adopted age-based modelling that only uses the asset attribute data to forecast replacement volumes. Not all available asset data is utilised in this modelling approach. Integrity of the relevant and assumed asset attribute data was sufficient to undertake this expenditure modelling.

### D.11.4 Asset population and age profile

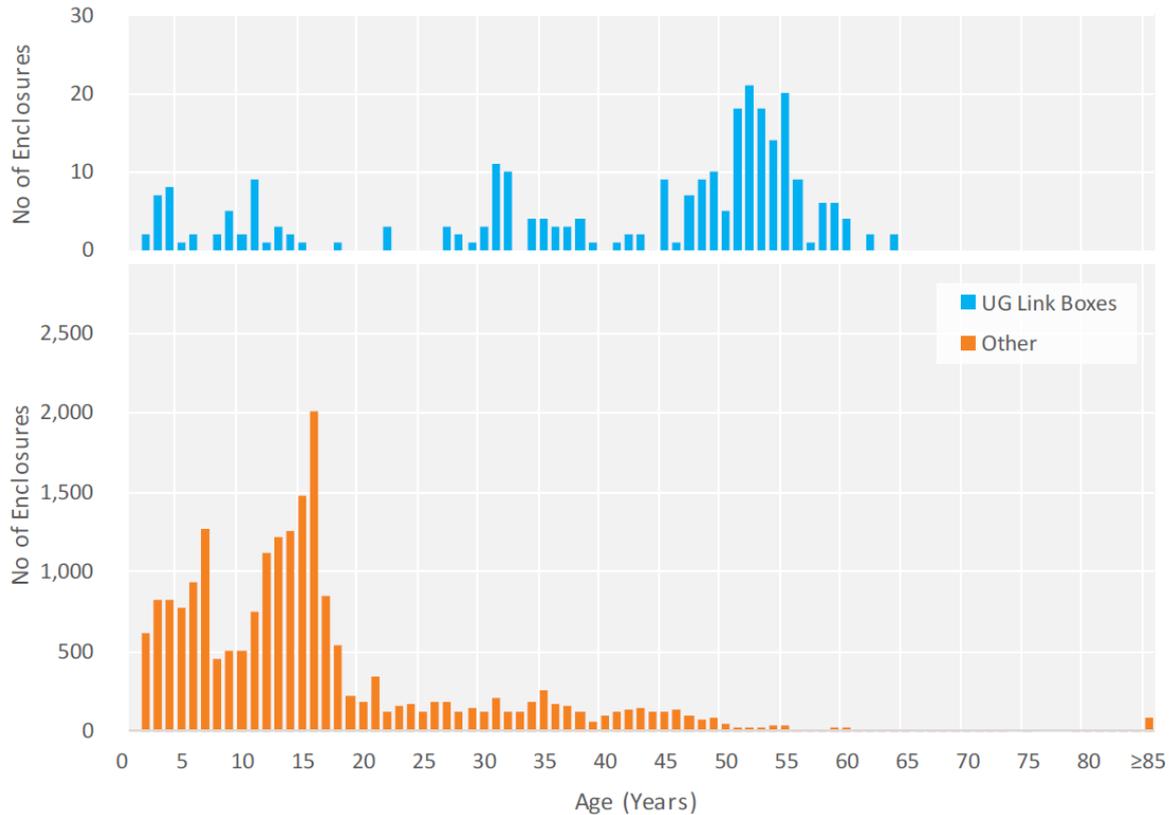
#### Asset population by age

Aurora Energy owns approximately 21,000 LV enclosures that are used in the LV supply network. The makes and types of enclosures vary widely due to the historical suppliers, subdivision designs and network ownership and operation.

A small number of LV enclosures are link boxes that were installed underground – as opposed to link pillars, which are above ground – that are distinctly different from the other types of enclosure, with a higher replacement cost. These specific LV enclosures are treated as a separate fleet (or sub-fleet) referred to by Aurora Energy as ‘underground link boxes’ and were primarily installed on the Dunedin network.

Figure D.14 shows the ages of the portfolio of LV enclosures. Aurora Energy has a total of 265 underground link boxes, with an average age of 41 years. Other LV enclosures have an average age of 17 years and make up the remainder of the 21,000 assets in the fleet.

Figure D.14: Low voltage enclosures age profile



Source: Aurora Energy, POD08 – Portfolio Overview Document | LV Enclosures

### Expected life

Aurora Energy had initially assumed the expected life for LV enclosures would be 40 years. In response to workshop questions, Aurora Energy stated:<sup>263</sup>

- *Our UG link boxes (Henley) appear to have already reached end of life based on anecdotal evidence and our inspections.*
- *We do not have any other data to support these expected lives other than our assumption.*
- *It is uncertain what other EDBs expected lives are as they classify their assets differently and/or we cannot source this information publicly.*

Given the lack of condition information at the time, it is not surprising that an assumed age was needed. However, given that it is not supported by reliable information, we considered that Aurora Energy's estimated expected life of 40 years was an unreliable assumption. Aurora Energy has since incorporated the findings of our analysis in section D.11 and increased the expected life to 47.5 years.

<sup>263</sup> Aurora Energy, P07 - Renewals - LV Enclosures, p. 15.

### D.11.5 Asset performance objectives, measures and targets

#### Reliability, safety, quality and any other output performance objectives

Aurora Energy has not set any performance objective or targets for LV enclosures such as assisted and unassisted asset failures, and number of shocks received. In response to us Aurora Energy stated:<sup>264</sup>

- *As covered during the earlier asset management session, once we have collected more failure information we will look to develop quantified performance targets.*
- *We are in the process of developing asset strategies to set objectives, which in time can contain performance metrics based on failure counts for example.*
- *We are also improving our data collection processes so that we are able to report on failures better in the future.*

While the above is a reasonable position considering the maturity of Aurora Energy's asset management system and the lack of reliable information, it would have been possible to draw from measures and targets used by other EDBs in New Zealand.

#### Past performance and forecast performance

Aurora Energy has not historically collected LV outage data – and so does not have any reliability or performance data for its LV enclosures.

Absent such data, Aurora Energy advised that:

- it has specific knowledge that the Henley underground link boxes are unsafe to operate live – and so has instructed its staff and service providers to only operated these de-energized, which limits LV network operability
- for other LV enclosures there is anecdotal evidence that there are relatively low levels of third-party incidents, and modest amounts of defects being found in the preliminary condition inspections (discussed in POD18)
- it has had one worker safety incident whilst carrying out a routine inspection of a pillar box with a metallic enclosure (P160/P260 type)<sup>265</sup>
- it has had very few incidents of the public reporting shocks from LV enclosures, except for one report of a dog receiving a shock.

One Australian EDB that we are aware of sets performance measures for the maximum number of shocks from LV enclosures. This target adjusted for Aurora Energy volumes is less than 1.5 shocks per annum (330,791 pillars with a target <23 p.a. -  $23/330,791 \times 21,000$ ). If such a target was adopted, then Aurora Energy's past experience may fall within tolerable risk levels.

The difficulty, of course, is that without reliable information or clarity as to what risk level is tolerable, it is not yet possible to conclude whether LV enclosures are providing an intolerable level of risk – and so what, and if any, enhanced renewal activity is appropriate in the circumstances.

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<sup>264</sup> Aurora Energy, P07 - Renewals - LV Enclosures, p. 9.

<sup>265</sup> These types of enclosures can become inadvertently live and, in this case, unfortunately it resulted in an arc flash incident during the inspection. Mitigation steps have since been put in place then to protect workers working on those enclosure types.

### D.11.6 Asset condition and modelling

#### Asset health / condition and asset subpopulations

The AHI methodology for LV enclosures is based on a simple expected life minus the asset age in the model and is not at this point informed by actual condition data. The inspection and condition data following completion of the current inspection programs could now be used to improve the asset health model by calibrating the replacement needs based on condition.

Using the age-based approach, Aurora Energy allocates percentages of the total fleet of LV enclosures to H1 to H5 health scores, which then categorises the quantities required for future replacement based on remaining life.

The available asset attribute information collected by the current inspection program could also be used to segment the fleet by types of enclosure with different levels of risk to the public – which could better inform the asset strategy revisions, particularly the inspection regime.

### D.11.7 Consequence of failure and risk modelling

#### Failure modes and consequences (safety, reliability, quality, other)

Public safety is a key driver identified by Aurora Energy in its POD18. However, consumers and other stakeholders have expressed the view that Aurora Energy should only incur costs where they are justified on the basis of an intolerable level of risk would occur otherwise in do nothing.<sup>266</sup>

We asked Aurora Energy about what level of risk it considered acceptable. Aurora Energy responded that:<sup>267</sup>

*We have determined it prudent to address the health of LV enclosures fleet given its inherent risk based on its location at ground level in the public domain (potential for serious injury or death). This is in line with our corporate risk matrix.*

A failure mode, effects and consequence assessment (FMECA) does not appear to have been carried out by Aurora Energy; however, key issues were listed in its AMP 2018–2028. One of the high risks are with metal enclosures that are not earthed, posing a heightened public safety risk – which is consistent with the failure models identified by other New Zealand EDBs.

Various failure modes and risks have been identified by other New Zealand EDBs. For instance, Top Energy (AMP 2018) stated:<sup>268</sup>

*Failure of a pillar is commonly due to foreign interference or poor installation. Poor installation will lead to internal failure, resulting in loss of supply and internal damage. There is very little risk beyond this with the exception of a neutral connection failure. Foreign interference by vehicle or vandalism can lead to live internal parts being exposed, which could result in personal injury.*

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<sup>266</sup> Customer Advisory Panel response to Aurora Energy CPP consultation document, December 2019, paragraphs 28 and 63; Aurora Energy's phone survey conducted by UMR during December 2019 and January 2020 indicated high level of satisfaction with current reliability of power supply (86%) with little appetite for improving reliability if prices go up (less than 8% prepared to pay high line charges for fewer unplanned power cuts).

<sup>267</sup> Aurora Energy, P07 - Renewals - LV Enclosures p. 9.

<sup>268</sup> Top Energy, 2018 Asset Management Plan, 27 March 2018, p. 182. Link: <http://topenergy.co.nz/wp-content/uploads/Top%20Energy%202018%20AMP%20Final%20Draft%20200318%20Rev%20-%20web.pdf>

Similarly, WEL Networks (AMP 2018) stated:<sup>269</sup>

*The principal risks and issues for Service and Distribution Pillars are:*

- *Damaged LV pillars may pose a risk to public safety; and*
- *Fibreglass type pillars are fragile and prone to damage.*

*LV pillars are part of the LV underground network and have been identified as having the highest public safety risk among our asset classes. This is due to the higher accessibility to the public. Safety risks include the probability of electrocution following damage to the unit and live parts being exposed to public contact. Minor issues involve vegetation build up around the pillar, obsolete types of pillars and location installed e.g. inside a private property.*

Likewise, Powerco (AMP 2019) stated:<sup>270</sup>

*LV boxes are predominantly installed in urban areas to supply nearby loads.*

*As they are above ground and accessible, they can present a public safety risk if not properly maintained. The key public risk is loss of security because of damage, degradation or vandalism, exposing live terminals.*

And:<sup>271</sup>

*A safety issue relating to LV boxes is that those of metallic construction can be inadvertently livened.*

And further:<sup>272</sup>

*Many reported defects and faults are because of physical damage, often caused by vehicles.*

It is clear from the above New Zealand context that the key failure mode is damage by third parties exposing live terminals. This is managed by public awareness campaigns and emergency response procedures and processes. While WEL Networks listed “LV pillars as the highest public safety risk among our asset classes” this is also related to third party damage, otherwise the risk is quoted in its 2018 AMP as “minor issues”.<sup>273</sup>

### **Risk assessment methodology**

Aurora Energy’s asset health assessment has not used the consequence of failure (i.e. criticality) to determine risk and to establish an optimum level of forecast replacement volumes. Aurora Energy stated that criticality will be only used to prioritise the delivery of work.

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<sup>269</sup> WEL Networks, 2018 Asset Management Plan, 29 March 2018, p. 160. Link: [https://www.wel.co.nz/UserFiles/WelNetworks/File/2018%20Asset%20Management%20Plan%20Web%20version\(1\).pdf](https://www.wel.co.nz/UserFiles/WelNetworks/File/2018%20Asset%20Management%20Plan%20Web%20version(1).pdf)

<sup>270</sup> Powerco, Electricity Asset Management Plan 2019, 2019, p. 220. Link: <https://www.powerco.co.nz/media/2064/2019-electricity-amp-powerco-vf.pdf>

<sup>271</sup> *Ibid*, p. 221.

<sup>272</sup> *Ibid*, p. 221.

<sup>273</sup> WEL Networks, 2018 Asset Management Plan, 29 March 2018, p. 160.

Without sufficient data on condition in the past, we acknowledge that a risk assessment may not provide valid or useful information. However, currently Aurora Energy's forecast volumes are driven by an assumed expected life – and so the forecast replacement volumes are also not validated by condition.

Moreover, there is now sufficient information from inspections carried out in 2019 and 2020 to inform a risk assessment that could be undertaken by Aurora Energy, and potentially prior to finalising this report. Aurora Energy has considered the findings in the draft report and revised its forecast. While not specifically undertaking risk assessments, the adjusted forecast considered our findings in the draft report and the practices of other EDBs.

Australian EDBs also have a mixture of metal, fibreglass and plastic covered LV enclosures and so their practices may also be relevant. By way of example, one Australian distributor based on our knowledge describes its asset strategy as inspection on a reactive basis following a fault or an enquiry from the public. Defects are identified by ad-hoc visual inspections or reported by general public and field crews.

Consequences of failures are minimised by adopting emergency response procedures and processes. This implies that EDBs consider the condition and modes of failure pose low risk to workers and the public except in the case of vehicle damage which can expose live terminals.

### D.11.8 Asset strategy and renewals model

#### Asset strategy

LV enclosures were not identified in the WSP report and as such they may not have considered these assets or may not have considered them as high-risk. Aurora Energy's AMP 2017-2027 identified LV cables – which include the LV enclosures – as being a moderate risk with a low residual risk when effective controls are in place. Aurora Energy's AMP 2018-2028 was updated to include a specific section on LV enclosures.

The POD18 (27 February 2020) can be viewed as the asset management plan for this fleet, or at least an overview of it. The initial renewal model for LV enclosures (MOD18 - 27 February 2020) followed an age-based asset replacement approach – with a normal distribution around the expected life of 40 years. This expected life assumption essentially embeds an assessed risk that implies the critical failure rate of the assets at that age will pose unacceptable risks to the public and workers.

Aurora Energy's maintenance strategy – as set out in its AMP 2018-2028 – is to adopt five-yearly inspections, to carry out minor repairs and identify replacements required and to do so more frequently if there is a high risk of third-party damage. The inspection strategy adopted by Aurora Energy is consistent with peers with a higher frequency focussed on high risk public areas and high-risk enclosure types; similar to the Powerco inspection regime.

The renewal strategy is to replace enclosures where conditions are found hazardous following inspections. The forecast volumes in MOD: 18 however were based on the number of enclosures exceeding a normal distribution of age around a mean of 40 years.

Table D.20 provides a comparison to peer New Zealand EDBs. While we acknowledge that other EDBs have had a replacement expenditure in place prior to 2020, the initial proposed expenditure by Aurora Energy was significantly higher.

Table D.20: Comparison of inspection strategy and replacement expenditures

EDB/Distributor	Source	Inspection Frequency	Expected Age (Years)	Prorated 5 Year Expenditure Forecasts <sup>274</sup> (\$M)
Aurora Energy (initial forecast)	POD18, MOD18 (27 Feb 2020)	5 yearly	40	\$9.3 <sup>275</sup>
Aurora Energy (adjusted forecast)	MOD18 (23 Apr 2020)	5 yearly	47.5	\$5.4 <sup>275</sup>
Top Energy	AMP 2026	3 yearly	45	\$2.3
WEL Networks	AMP 2013 & 2018	3 Yearly	45	\$2.0 (2013) \$1.75 (2018)
Powerco	AMP 2018	High risk areas 2.5 yearly, other areas 5 yearly	Undefined	\$1.1
Australian Distributor	Not public	Public reports/ spot inspections	30 years with 25% > expected age	\$1.8

These initial forecasts quantities did not appear to be consistent with industry practice for LV enclosures (or pillars). The volumetric forecasting approach without historical condition data was likely resulting in a higher expenditure forecast than is reasonable in the circumstances.

Aurora Energy has subsequently updated forecasts based on a revised upwards the asset life assumption for the above ground LV enclosures pillars to 47.5 years (MOD18 - 23 April 2020). The updated medium asset life age based on our analysis of apparent risks presented in the recent inspection data as follows.

The initial POD18 (27 February 2020) indicated that around 30% of the LV enclosures have been inspected. The inspection data for four separate inspection programs, having different inspected volumes, has subsequently increased the quantities (see response to RFI D012). The total inspected is now 10,355 which is 49% of the total of 21,000 units.

We used the inspection data results provided to plot defects shown in Figure D.15 for each of the data sets. Other than the specific risks and age associated with underground enclosures and those with the P160/P260 metal enclosures, the percentage considered hazardous is relatively low at between 0.3% and 0.4% of the inspected fleet quantities.

We then used the following assumptions to derive a weighted average of the defects across the whole fleet for above ground LV enclosures:

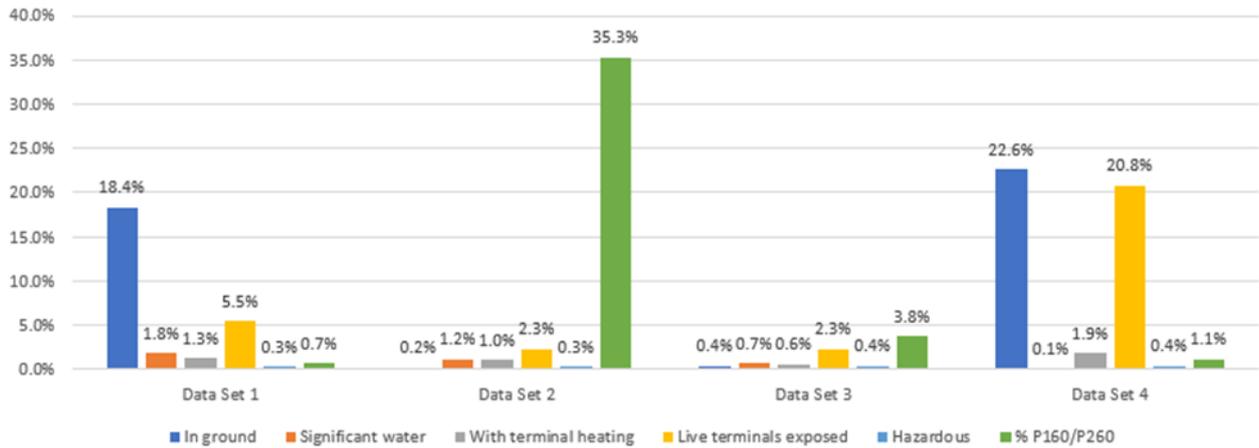
- all in ground types are not included and assumed to need replacement
- the number of P160/P260 enclosures have all been identified during these four inspection programs as a matter of priority.

<sup>274</sup> Forecasts are prorated considering relative number of LV enclosures and in one case the number of customers.

<sup>275</sup> Excluding underground enclosure replacements.

The results of the analysis indicate that where there are bare conductors or terminals, the percentage of potentially hazardous overall is 0.4%. Further analysis of these show that the percentage was 6% for P160/P260 enclosures and only 0.2% of other above ground enclosures. This suggests inspectors recognised the higher risks with these types of enclosures and identified them accordingly.

Figure D.15: Defects within each inspection data set



Source: Aurora Energy inspection data, farrierswier and GHD analysis.

Table D.21: Estimated defect in the total fleet (weighted average)

Hazard Type	Number	% of Total
P160/P260 <sup>276</sup>	829	4.0%
With terminal heating	224	1.1%
With water	228	1.1%
Considered hazardous total	84	0.4%
P160/P260 considered hazardous	49	5.9%
Other LV enclosures considered hazardous	35	0.2%

Source: Aurora Energy inspection data, farrierswier and GHD analysis.

### Options and data inputs

The following assumptions had been made by Aurora Energy in POD18 and MOD18:

- expected lives of LV enclosures was assumed to be 40 years and together with the age profile this is driving the forecast volumes – the expected life of above ground enclosures was increased to 47.5 years in the revised MOD18 (23 April 2020)
- underground link boxes are in poor condition creating unacceptable safety and reliability risks and need to be replaced as soon as possible – we agree with this assessment, including consistency with the recent inspection data

<sup>276</sup> The number of P160/P260 enclosures is based on the assumption that all of these types have been inspected.

- the P160/P260 metal enclosure types have been identified to pose high risks where a few cases have occurred where shocks have been received – in comparison to other potential risks for electrical shocks in LV networks, such as broken neutrals, the number of reported incidents should form part of a risk assessment approach in future updates to the modelling.

We did not agree with the use of age data assumptions without reviewing sensitivity to the assumptions, conducting risk assessments or making comparison with other EDBs.

The data from our assessment of risk exposure in Table D.20 and other EDB expenditure levels suggests that the assumption of 40 years for the expected life of the above ground enclosures was not valid and leading to an overstated volume forecast.

### **Data outputs and replacement forecast**

Aurora Energy's forecast is based on a volumetric P×Q forecast model and uses the following inputs to determine the volumes (Q):

- the above data inputs (i.e. LV Enclosure age profile and expected life assumption)
- a normal distribution around the expected life of 40 years (the above ground enclosures was revised to 47.5 years).

The revised expected life of 47.5 years and forecast volumes now includes consideration of condition data findings and comparison with other New Zealand replacement volumes and expenditure levels.

The unit cost replacement for replacement of LV underground enclosures is reasonable; however, we initially considered that the unit rate for other LV enclosures was high and that it should be reduced below the current rate of \$5,000 per unit, based on comparable rates for Australian utilities and contractors.

Aurora Energy subsequently undertook a comparison of LV enclosure unit rates with other EDBs and provided details on rates and unit rate scopes for 25 past Aurora Energy projects. Our assessment of the efficiency of unit costs and deliverability is set out in section C.11 for the LV enclosures and we found the assessment by Aurora Energy is not unreasonable considering the impact of projects that require relocation, or replacement of LV cabling and other costly site works.

### **Validate model outputs**

Aurora Energy did not complete any sensitivity analysis for the input data assumptions. We consider sensitivity analysis is important based on the uncertainty around the key assumptions when actual data is unavailable. In this case the data available from the recent inspections can be used to validate the forecast replacement volumes.

We compared the expenditure outputs related to above ground enclosures with one other EDB in Australia and three EDBs in New Zealand. The annual expenditure – adjusted by asset population – ranged from \$1.1 million to \$2.3 million over a five-year period compared to Aurora Energy's initial forecast of \$9.3 million over the review period. The comparisons ranged from 12% to 25% of Aurora Energy's forecast expenditure for above ground LV enclosures.

We used the data assessment in Table D.21 to recast the required volume replacements from RY22 to RY26 and with the following assumptions:

- all underground enclosures to be replaced by the end of the period
- the replacement of P160/P260 enclosures reduced from 100% to 50% (based on the assumed quantity of this type of enclosure) over the period from RY20 to RY26

- the replacements per annum due to third party damage equal to 0.4% of the total population.<sup>277</sup>

This adjusted Aurora Energy's original forecast replacement rate of 1.9% per annum to 1.1% on average over the review period. Aurora Energy also reported in the P07 presentation that there were 40 LV enclosures requiring replacement following current inspections. Assuming this was based on 30% of the population inspected, the replacements required would equate to 133 over the total population (0.6% of the total). The adjusted forecast replacement volume is 1.1% per annum – which is consistent with this finding.

Another test of whether the adjusted volumes are reasonable is to use the current model to determine the adjusted expected life of LV other enclosures that would equate to this same forecast. The model estimated 47.5 years which is not dissimilar to the expected life of 45 years nominated by Top Energy and WEL Networks in their AMPs.

Aurora Energy has adjusted the expected life input parameter in the MOD18 (23 April 2020) to 47.5 years to produce revised replacement volume aligned to the above adjustments to then forecast expenditure of the review period.

The adjusted replacement forecast is \$9.5 million in total and \$5.4 million for the above ground enclosures. This contrasts with the expenditure forecasts of between \$1.1 million to \$2.3 million of the other New Zealand EDBs (refer to references) that we considered, some notably having had programs in place previously. The long run replacement rate forecast by Aurora Energy is expected to reduce to 66% of the above forecast while it is reasonable to expect that other EDB expenditure may increase.

### D.11.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of:

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's LV enclosure renewal program over the CPP and review periods are that:

- **Inputs and modelling** – we agree with the adjusted age-based modelling approach for the renewal program forecast.
- **Asset strategy** – the adjusted replacement forecast is consistent with the issues and hazards found in inspections completed to date with around 49% of the total population inspected based on the data provided. We agree that all the underground link boxes require replacement by RY26.
- **Benchmarking** – the adjusted replacement expenditure is not unreasonable compared with other New Zealand EDBs where replacement programs have already been in place in past years.

In our view, the revised expenditure forecasts for the LV enclosure replacements over the CPP and review periods appear consistent with the expenditure objective. We formed our view after reviewing the CPP proposal (including the updated forecasts) and the supporting material and clarifications provided by Aurora Energy.

This assessment supports respective findings detailed in section C.11.5 (Assessment of forecast method used), C.11.5.2 (Expenditure Justification) and C.11.5.6 (Interaction with other forecast expenditures).

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<sup>277</sup> Based on data available from the Australian EDB.

## D.12 PROTECTION RENEWAL (R7)

### D.12.1 Information provided

Table D.22 presents the information that has been provided by Aurora Energy relevant to renewals modelling and the associated asset strategy for protection assets.

Table D.22: Information provided

Title	Reference	Date
POD24 – Protection Portfolio Overview Document	E-19	27 February 2020
Protection Relays Renewal Forecast	E-18	27 February 2020
Protection System Progress Report	PR-83	3 February 2020
P11 Renewals – Zone Subs & Protection	V-99	26 March 2020
RFI D293 - Aurora Pricebook Review Final 21 Jan 2020	V-40	15 March 2020
AE-Policy-04 - Asset Management	IPC-980	6 December 2019
Aurora-Energy-2018-2028	IP-1246	12 December 2019
Aurora-Energy-2019-AMP-Update	IP-1247	12 December 2019
RFIs D244-D250	RFI responses set out in Table I.2	Various dates

### D.12.2 Other information relied on

Table D.23 sets out the other information that we relied on when reviewing Aurora Energy’s protection replacement expenditure.

Table D.23: Other information relied on

Title	Author	Date
State of the infrastructure report 2017/18	Western Power	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	2 October 2017
Powerline Asset Management Plan	SA Power Networks	January 2019
Independent Review of Electricity Networks	WSP	21 November 2018
Electricity Asset Management Plan 2019	Powerco	2019
Independent Verification Report – Transpower’s RCP3 Expenditure Proposal (2020-25)	Synergies and GHD	12 October 2018

### D.12.3 Data and integrity

#### Definition of asset data and register

Data availability for this fleet was assessed by WSP in its 2018 report. Identified data gaps were mainly around attributes with type of relay calculated to be 4.1% unknown and location unknown 4.6% – which are comparatively low.

#### Data quality

We consider that the type data and past performance data integrity is sufficient to provide accurate forecasting in the renewal model.

### D.12.4 Asset population and age profile

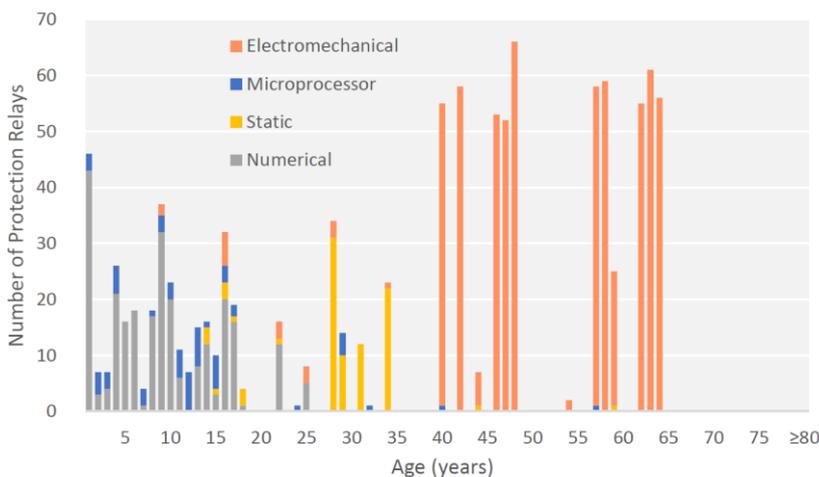
#### Asset population by age

Aurora Energy indicates in POD24 that there are 496 relay schemes by age. Based on schemes there are 187 electromechanical schemes, 43 static relay schemes and 266 are numerical/microprocessor relay scheme technologies.

Protection relays are located indoors and so are not exposed to extreme weather conditions. Similarly to telecommunication equipment, temperature is a factor in the performance and life of modern relays. However, this should not be a factor impacting the life of relays in the Aurora Energy fleet in the South Island of New Zealand. Aurora Energy has segmented the population by the general technology type.

Aurora Energy presented at the March 2020 workshop that there are 1,030 protection relays of which 621 (60%) are electromechanical type, 90 (8.7%) static, 61 (5.9%) microprocessor and 258 numerical (25%). Figure D.16 shows the age profile of the protection relay types.

Figure D.16: Protection relay age profile



Source: Aurora Energy, POD24 – Protection Portfolio Overview Document

#### Expected life

Aurora Energy has stated that protection relay end of life generally relates to obsolescence, including lack of spares and higher costs to maintain. It is normal industry practice for relays to be replaced due to obsolescence and spares availability, rather than reliability of operation being the driver.

Aurora Energy has set an expected life for electromechanical relays at 40 years and 20 years for both static relays and microprocessor electronic types respectively. This is consistent within the industry, for example:

- **SA Power Networks** – sets expected life for electromechanical relays at 40-60 years, electronic relays 15-25 years, and microprocessor relays at 15-20 years.
- **Transpower** – sets expected life for electromechanical relays at 35 years; all electronic relays 20 years.
- **Powerco** – sets expected life for electromechanical relays at 40 years and electronic relays at 20 years.

In its report (page 167), WSP noted that electromechanical relays have “an expected life of around 50 years, whereas modern digital relays have an expected life of around 20 years”.

Approximately 61% of the relays on the Aurora Energy network are electromechanical and nearly all have exceeded their life expectancy and spares for them are generally no longer available (due to obsolescence). Many of the static relays have also exceeded their expected life by 10 years or more. Many of the microprocessor relays will reach expected life over the next 10 years. Together, this is resulting in a crowded need for expenditure over the next 10 years due to Aurora Energy not having started a replacement program earlier.

SA Power Networks reports that 63% of its relays are over 25 years of age, which is not as high as Aurora Energy’s age position. A replacement program has been in place for at least the last 10 years and increasing going forward.

Powerco indicates that the number of electromechanical relays is 35% of the total compared to 61% for Aurora Energy. In recent years Powerco has replaced substantial numbers of both electromagnetic and static relays.

These comparisons indicate that Aurora Energy’s average age of protection relays presents a much higher risk position compared with SA Power Networks and Powerco – which is consistent with findings in the WSP independent report.

## D.12.5 Asset performance objectives, measures and targets

### Reliability, safety, quality and any other output performance objectives

Aurora Energy has not set any performance level objectives or targets for protection relays. We consider interim measures could have been put in place using performance measures used by other EDBs such as “% correct operation of relay scheme”, “Failure rate for each relay type”, “#Human Element Incidents” and other similar measures.

We acknowledge Aurora Energy’s intent to implement such measures in the future – which was been confirmed in the response to RFI 245.

### Past performance and forecast performance

The WSP report (P176) states that protection relays:<sup>278</sup>

*The failure of the protection system could be the relay itself or the battery, instrument transformers or secondary wiring. However, they are highly reliable assets so typically there are not too many failures attributed to the asset class. Aurora Energy has not historically undertaken root cause analysis of these failures.*

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<sup>278</sup> WSP, Aurora Energy – Independent Review of Electricity Networks, Final Report, 21 November 2018, p. 176. Link: <https://www.auroraenergy.co.nz/assets/Independent-Review-Mar-2018/WSP-Final-Report-PS109832-ADV-REP-003-RevD.PDF>

After looking at the outage data, WSP found that:<sup>279</sup>

*The outage data shows only 19 outages since 2003 that are attributed to a component of the protection system. Of these 13 were attributed to the secondary wiring, four to the instrument transformers and two to the relays. The predominant cause of the outages was human error (which we observe is not uncommon due to the complexity of protection schemes), incorrect protection setting or incorrect maintenance/testing. Only one outage related to the deteriorating of a relay occurred during 2010.*

*The outage data results do not indicate a systemic program with relay failures causing outage.*

WSP estimated an average of between 10 and 25 incidents per year since 2003 where a line was identified as having fallen to the ground as a result of equipment deterioration. WSP also estimated that 30 of these events resulted in a live conductor on the ground that was not cleared by the immediately upstream protection device, which was a significant safety concern.

Consistent with this, Aurora Energy states within the POD (page 5) that:

*over the last 16 years we have recorded 40 incidents (that have contributed to consumer outages) involving incorrect protection relay settings.*

This equates to 0.2% of relay failures per annum in the past 16 years due to one type of human error.

WSP states:<sup>280</sup>

*In a four-year period, 20 faults on the HV network were not cleared by the immediately up-stream protection asset.*

We have not sought to validate the above WSP findings by undertaking our own assessment of the same data or by inspecting individual assets. However, through our verification we have not become aware of any information that invalidates WSP's findings.

The data above equates to, on average, five faults per annum in the last four years – a protection relay failure rate equating to 3.5% per annum.

The failure relays found through testing should be the predominate type of failure identified and very few operational failures should result in the operation of back up protection and consequential larger loss of supply events. A typical risk profile – using relay performance as an indicator – can be identified by comparing performance with the two Australian EDBs noted below, both of what are increasing the number of relay replacements and have had programs in place over the last 10 years:

- **SA Power Networks** – reports current protection relays failures increasing from 32 to 58 in four years (increasing to around 0.25% pa)
- **Western Power** – has reported an average of 83 relay failures per annum (approximately 0.76% pa).

Both those networks have failure rates noticeably lower than those experienced by Aurora Energy in recent years, suggesting that this fleet faces above average risk at present.

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<sup>279</sup> *Ibid*, pp. 176–177.

<sup>280</sup> *Ibid*, p. 178.

## D.12.6 Asset condition and modelling

### Asset health / condition and asset subpopulations

An AHI methodology has not been developed for this asset class and therefore is not provided in POD24. An AHI model is not as useful for assets that need to be replaced due to obsolescence rather than condition or poor performance; however, for completeness the diagrammatic illustration of asset health is helpful to provide stakeholders (the board, management, the Commission and others) with a dashboard perspective of the overall health of the protection assets.

Modelling of failure rates by age or condition has not been used in the renewal model for the same reason that the expected life is used to determine the optimum replacement timing before consideration of deliverability and priority.

The population is segmented by technology type, which is consistent with industry practice.

## D.12.7 Consequence of failure and risk modelling

### Failure modes and consequences (safety, reliability, quality, other) that drives replacement expenditure

Ensuring network safety and protection of assets is a key objective of protection systems. Energy at risk is not usually a key driver, but if primary protection failures increase or high numbers of incorrect settings are prevalent then supply outages will become an issue.

Aurora Energy has not developed its own specific FMECA studies for this fleet, which will be part of asset management developments during the CPP and review periods. It has relied on industry experience to determine the current asset strategy, which is generally laid out in its AMP and the POD.

### Risk assessment methodology

Aurora Energy has not developed specific asset strategy plans for this fleet and has not documented options considered nor conducted its own risk assessment models to support the defined asset strategy.

At this point in its asset management journey, Aurora Energy has relied upon industry practice and accepted the findings of the WSP report to address identified risks. Aurora Energy indicated that risk assessments will be used to prioritise asset replacements over the CPP and review periods.

## D.12.8 Asset strategy and renewals model

### Asset strategy

The replacement strategy adopted by Aurora Energy is consistent with industry practice. Aurora Energy has decided to replace all electromechanical relays by RY24, and while other EDBs still have some of these relay types in service, Aurora Energy is planning to remove all of these relays before it has deliverability issues to complete these replacements prior to the replacement of all the solid-state relays in RY25.

The maintenance interval has been reduced for electromechanical relays from four-yearly reduced to every two years. This is required to keep them in service and to increase the chance of detecting failures before the protection system are required to operate.

The electronic based relays – including solid state relays – will begin from RY25 and continue through to RY30. This strategy is consistent with Transpower’s asset strategy for their electronic based protection systems fleet described as follows:<sup>281</sup>

*Transpower’s overall strategy for protection assets is to replace relays on obsolescence or endemic failure, replace relays based on unavailability of spares or where a model shows signs of endemic failure, subject to a maximum life expectancy of 20-25 years.*

### Options and data inputs

Aurora Energy has made the following assumptions:

- the expected life and asset age is a reasonable proxy for increasing failure rate and future obsolescence for protection relays and is consistent with industry practice for protection relays
- the oldest relay in the scheme represents the scheme age – while this assumption could potentially overstate the replacement timing, it is likely that most of the relays would be of the same age within a scheme.

We agree with the approach to use asset age in the model, and consider that the data availability and its quality is sufficient to provide reliable input to the model.

### Data outputs and renewal modelling

Aurora Energy uses a volumetric P x Q forecast model and uses the following inputs to determine the volumes:

- protection scheme age profile – as a proxy to risk
- the life expectancy of the different types of protection relays – electromechanical relays are obsolete and their lives have been set to zero
- using a simple age-based, remaining life methodology to determine replacement quantities over the 10-year period.

The relay schemes that will be replaced within the zone substation portfolio have been removed from this dedicated protection renewal program.

Replacement cost inputs to the model have been applied correctly. We have addressed assessment of the efficiency of unit costs and deliverability in Appendix C for all programs.

### Validate model outputs

The outputs can be compared against other industry networks. Aurora Energy has forecasted replacement of approximately 30 schemes per annum (~45 to 60 relays per annum), which is a replacement rate of 6% per annum predominantly electromagnetic relays during the CPP and review periods.

In comparison, replacement rates for other EDBs are lower – which is expected given that the average ages of the fleet much younger than Aurora Energy’s fleet:

- **SA Power Networks** – its relay replacement rate is forecast to be 1.7% reducing to 1.4% over the next five years. A replacement program has been in place for at least the prior 10 years.

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<sup>281</sup> Synergies and GHD, Independent Verification Report – Transpower’s RCP3 Expenditure Proposal (2020-25), 12 October 2018, p. 232. Link: [https://comcom.govt.nz/\\_data/assets/pdf\\_file/0033/107979/Final-verification-report-12-October-2018.PDF](https://comcom.govt.nz/_data/assets/pdf_file/0033/107979/Final-verification-report-12-October-2018.PDF)

- **Western Power** – it has forecast a relay replacement rate of 3.3% over the current five year regulatory period. It appears to have a higher age profile compared to SA Power Networks, but much lower than Aurora Energy’s.

Potentially the replacement quantities forecast by Aurora Energy for electromechanical scheme replacements may be a risk adverse position with the model using an expected life of zero to flag up immediate replacement for *all* electromechanical relay schemes. Deferral for some schemes located at less critical zone substations and with lower criticality (and overall risk) could have been assessed as an option.

However, doing so, it is important to note that some relays within the fleet may not be suited:

- **Obsolete relays** – the WSP report (at page 186) stated that there were five specific types of relays that are now obsolete and are consistently losing calibration between maintenance cycles and these featured in the list of 13 zone substations identified in the WSP report (at page 180). These would be obvious choices for replacement.
- **Solid state relays** – these currently have reached around 30 years of life, 10 years longer than the nominated asset life for these relays. Extending the life further than RY25 is not an option. However, this does suggest potential for the younger microprocessor relays (i.e. electronic) to perform reliably beyond 20 years if OEMs would provide the necessary needed support.
- **Electronic relays** – the long run replacement average for electronic relays having a 20 year expected life will be 5% and if extended to 25 years would reduce to 4% p.a. Aurora Energy has indicated in response to RFI D244 that it may consider extending the life of digital relays in the future. This does not impact on the replacement relay volumes the CPP forecast.

Aurora Energy did not complete any sensitivity analysis for the asset age assumptions in the input data. Table D.24 shows the potential reduction of expenditure over the periods RY20-RY26 and RY20-RY30 based on two different input assumption scenarios.

From this sensitivity analysis we conclude that:

- deferring expenditure for the replacement of electromagnetic relays is not warranted against the safety risks and practicalities of replacing complete substation protection systems – this supports Aurora Energy’s strategy to replace all electromechanical relays by RY24
- the relatively high replacement rate of 6% per annum during the CPP and review periods therefore does not appear unjustified
- extending the life of modern relays has a significant impact on future expenditure and should form part of current asset strategy options to work with OEMs (and at an industry level) on providing sufficient support.

**Table D.24: Sensitivity to input data assumptions**

Revised Input	Expenditure Reduction RY20-RY26 (\$M)/(%)	Expenditure Reduction RY20-RY30 (\$M)/(%)
Expected life of electro-mechanical relays increased from 0 to 50 years	-\$0.33M (4.5%)	-\$0.55M (3.0%)
Expected life of microprocessor and numerical relays increased from 20 to 22.5 years	\$0M (0%)	-\$3.0M (16.0%)

Source: farrierswier and GHD analysis

### D.12.9 Our findings

Schedule G5(f) of the IM requires the verifier to provide an opinion as to the reasonableness and adequacy of any asset replacement models used to prepare the capex forecast including an assessment of:

- the inputs used within the model, and
- the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.

Our findings on Aurora Energy's protection renewal program over the CPP and review periods are that:

- **Inputs and modelling** – the inputs used in the renewal model are appropriate including the key assumptions related to this asset class which includes a sound underpinning asset strategy.
- **Asset strategy** – Aurora Energy has applied an appropriate method within the renewal model, appropriate for the asset type, which is also consistent with industry practice and hence likely to promote the expenditure objective.
- **Benchmarking** – Aurora Energy benchmarks well with two Australian EDBs, which supports the reasonableness of the forecast replacement volumes.

Based on our assessment of the CPP proposal and supporting material, the forecasts for the protection renewals over the CPP and review periods appear consistent with the expenditure objective.

This assessment supports respective findings detailed in section C.12.5 (Assessment of forecast method used), C.12.5.2 (Expenditure Justification) and C.12.5.6 (Interaction with other forecast expenditures).

# Appendix E Reliability modelling

## E.1 OVERVIEW

Aurora Energy developed two models – one to forecast unplanned reliability (the ‘unplanned model’), the other to forecast planned reliability (the ‘planned model’). Both forecast the reliability outcomes that may result from Aurora Energy’s proposed expenditures and other non-asset causes. In this appendix, we review the forecasting models, inputs, assumptions and approaches used to forecast those outcomes.

The unplanned model provided by Aurora Energy forecasts pre-normalised and normalised reliability over the CPP and review periods, which is relevant when assessing whether Aurora Energy’s proposed quality standard variation is realistically achievable (as required by clause G3(2) of the IM), which we consider further in sections 3.2 and 3.4.

The planned reliability model provides an unadjusted forecast and a de-weighted forecast that considers the Commission’s changes to the incentive rates for DPP3 that includes a 50% de-weighting of outages meet a specified minimum notification requirement.

Aurora Energy currently reports two reliability metrics to the Commission and proposes to continue with the same metrics as part of the CPP – namely, SAIDI and SAIFI. These metrics are also reported separately for outages caused by planned and unplanned events.

As noted in section 3.4, Aurora Energy proposes to noticeably increase its unplanned normalised SAIDI and SAIFI limits to reflect more recent historical performance data and the impact of proposed expenditure, while otherwise retaining the same method used to determine the equivalent DPP limits (e.g. setting the unplanned reliability limits two standard deviations above the target).

Aurora Energy is not proposing any changes to the planned reliability DPP3 annualised limits.

In sections E.4 and E.5 we discuss Aurora Energy’s approach to forecasting both planned and unplanned SAIDI and SAIFI and the impact of key assumptions made. To aid our analysis we have developed methods to provide alternative forecasts to cross-check against those developed by Aurora Energy.

We reviewed the models and forecasts in stages – with an initial review of models and findings in our draft report, followed by subsequent discussions with Aurora Energy, and then review of the final updated models and forecasts. Our final report addresses the latest forecast model versions with relevant comments as to how Aurora Energy addressed the matters raised in our initial findings and discussions.

Expenditure on asset renewals and maintenance affects how asset strategies improve individual asset failure rate performance and therefore unplanned reliability. Planned reliability outcomes are affected by expenditure (and volumes) for asset renewals as often outages are needed to undertake such activities. Below we provide background on the links between the drivers for unplanned and planned reliability to network performance outcomes. This supports our review of Aurora Energy’s models and forecasts.

## E.2 BACKGROUND

### E.2.1 Link between asset reliability, expenditure, and network unplanned reliability

This section explains the link between proposed expenditure, impact on asset condition and age, and the impact on *unplanned* reliability.

Aurora Energy is not projecting improvement in the network unplanned reliability even with the proposed increased level of expenditure. The key reason for this is that while the current high-risk assets are being targeted for replacement over the CPP and review periods, other assets will continue to reach their end of life – which maintains some upward pressure on unplanned reliability.

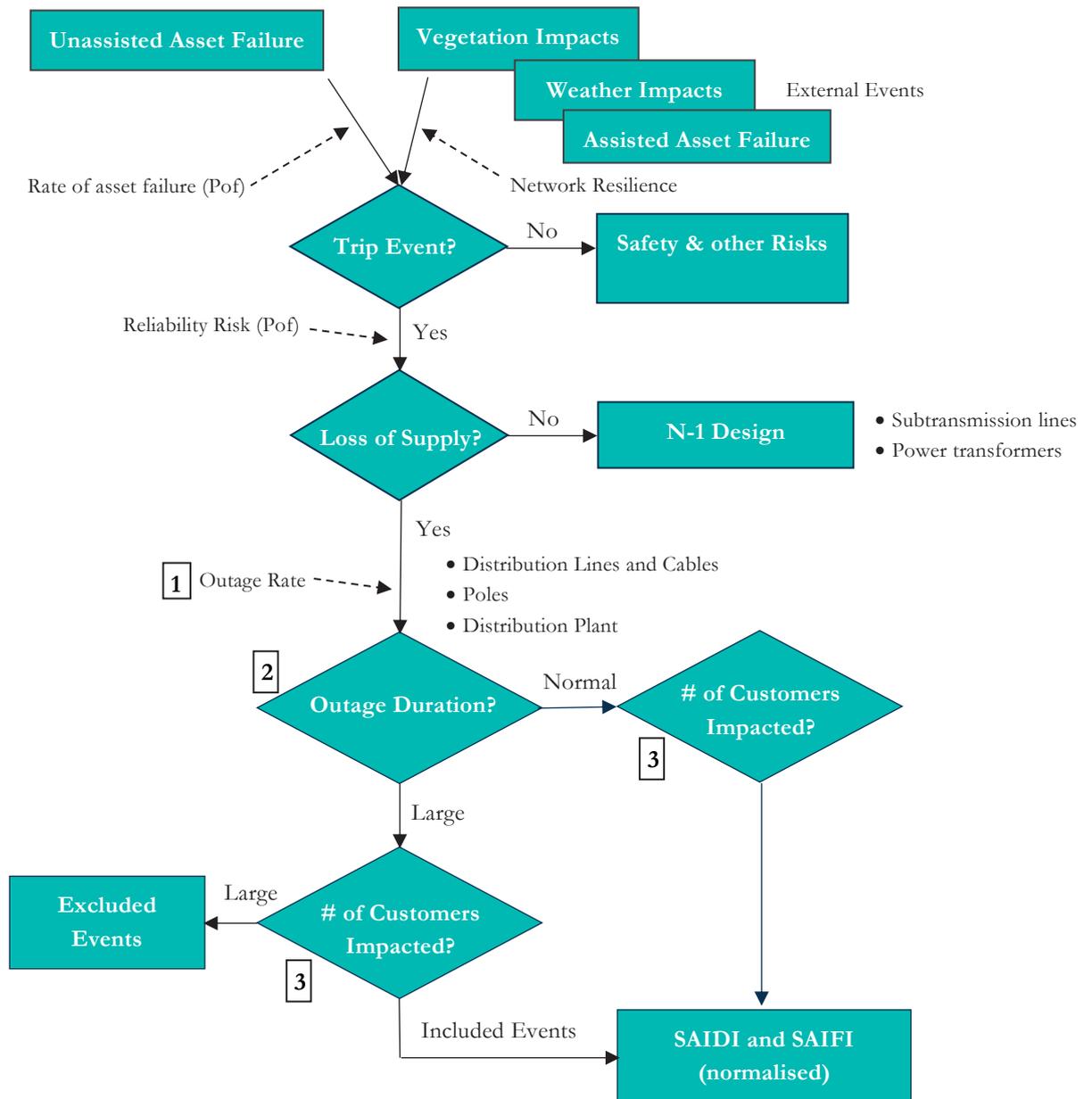
Aurora Energy has effectively aimed expenditure at addressing safety risks with reliability being secondary. Reliability is planned to slowly improve as assets are renewed; however, these renewals are being based on individual fleets assessed by comparing expected reliability benefits (measured using VoLL) to costs.

To help illustrate, Figure E.1 shows the flow on effect of the cause of outage events. These are:

- **Unassisted asset failure events** – as the assets age (or more specifically condition worsens), the rate of failure (Pof) increases and this leads to loss of supply events and increases in unplanned SAIFI and SAIDI network reliability. Not all asset failures will contribute to a loss of supply event as shown. So, targeted expenditure is directly related to improving or maintaining the net impact of asset failures on network reliability.
- **Assisted failure events** – these are external events (e.g. car hit pole) that typically can only be mitigated through reducing network exposure or through public communication campaigns to reduce the number of events. Expenditure for this reason is usually targeted at public safety.
- **Weather impacts** – these are external uncontrollable events that can only be mitigated by building a more resilient network over time. Expenditure for this reason is more difficult to justify. Renewal of assets (those exposed to weather impacts) will, however, inherently improve resilience of the network.
- **Vegetation impacts** – these are partly controllable to the extent permitted by regulations. They are also often coincident with weather related events (high winds). Targeted expenditure to maintain clearances to lines is therefore optimised towards reliability improvements and cost savings.

The parameters shown in the Figure E.1 will vary year on year. For example, the number of weather-related events. However, statistical distributions can be used to approximate the probability of such events affecting reliability. And so, the parameters *can* be modelled to predict future network performance with the same statistical distributions in each case (or the mean, which Aurora Energy has done).

Figure E.1: Relationship of Asset failures to Network Reliability



In its unplanned reliability model Aurora Energy uses the following historical outage data:

- # of faults (1 in Figure E.1)
- outage duration (2 in Figure E.1)
- # of ICP Affected (3 in Figure E.1).

Aurora Energy categorises outage event causes under the following types:

- distribution cables
- distribution conductors
- distribution transformers
- ground mounted switchgear
- pole mounted fuses

- pole mounted switches
- poles
- non-asset (weather and assisted failures)
- vegetation.

Contributions for each category to unplanned reliability can then be calculated as follows:

$$SAIDI\ Contribution = \#\ of\ faults \times\ Outage\ Duration \times\ \# \ of\ ICP\ Affected$$

$$SAIFI\ Contribution = \# \ of\ faults \times \# \ of\ ICP\ Affected$$

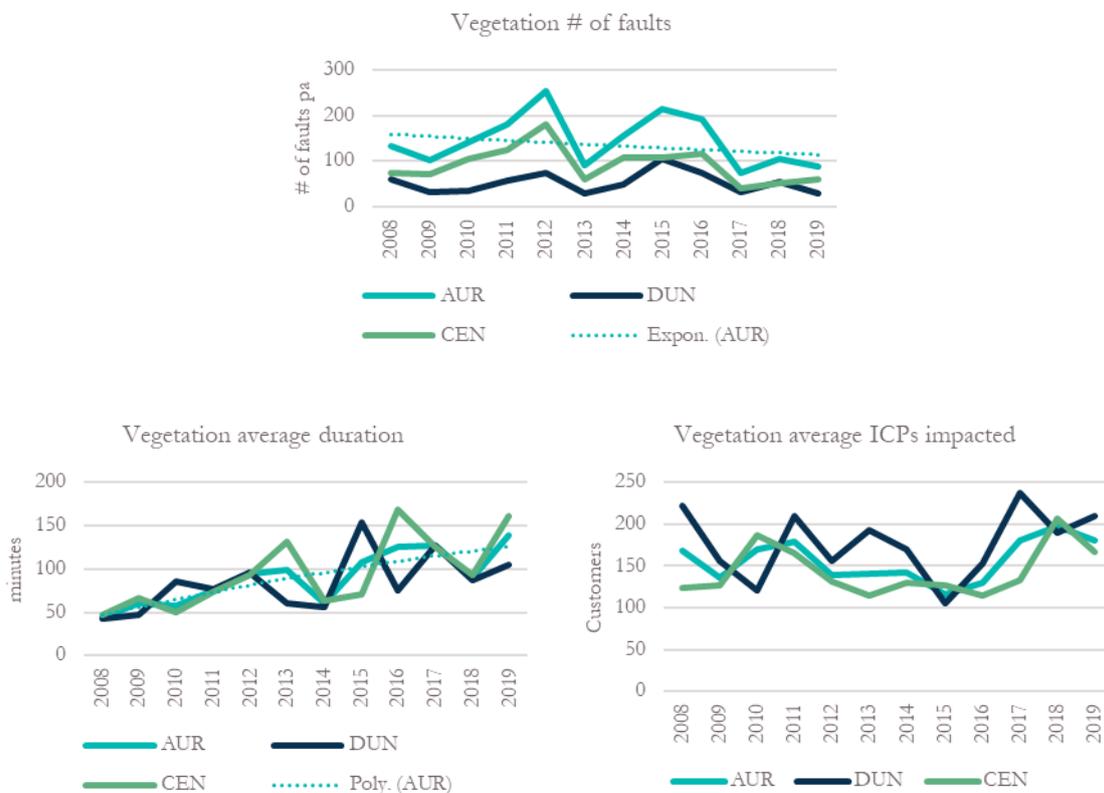
$$CAIDI\ Contribution = Outage\ Duration$$

Figure E.1 and the above formula indicate that SAIFI and SAIDI can be improved through expenditure on improving asset reliability.

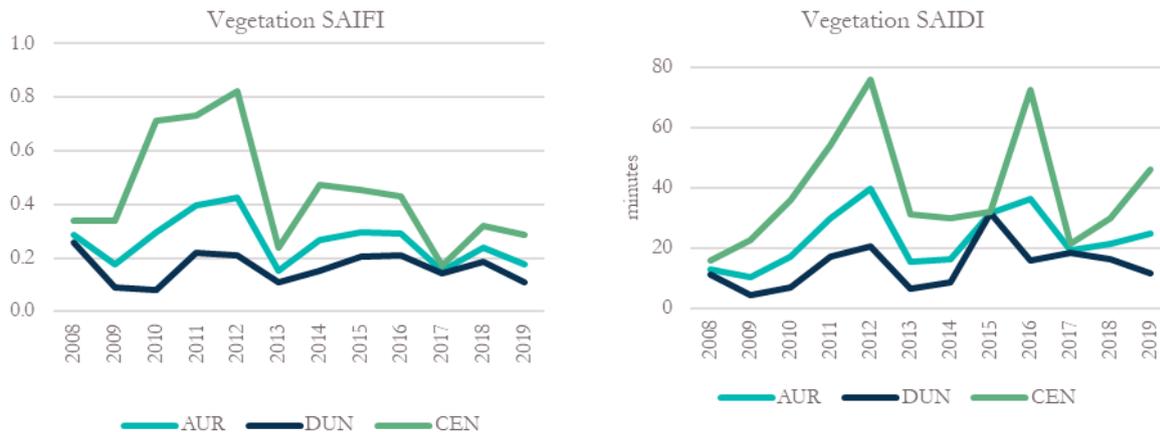
SAIDI can also be improved through operational expenditure to both the response and repair time to return supply to customers (such as 24/7 response team availability). Redesign of network segments and/or system automation can improve either SAIDI or SAIFI or both depending on the scheme.

Figure E.2 shows the historical contributions due to vegetation impacts based on data provided by Aurora Energy.<sup>282</sup>

Figure E.2: Unplanned SAIDI and SAIFI contributions caused by vegetation



<sup>282</sup> Note that the definition and differentiation from other causes, and the selection of the cause following an event, could somewhat impact the accuracy of the data.



Source: Aurora Energy data, farrierswier and GHD analysis.

## E.2.2 Link between expenditure and planned network reliability

This section explains the link between proposed expenditure on asset renewals and *planned* network reliability.

The equations for calculating planned SAIDI and SAIFI are the same as the unplanned equations shown above, except that the “# of faults” (more appropriately # of unplanned outages) is replaced by the # of planned outages.

Aurora Energy has identified the types of work that have required planned outages in the past and those that will require outages in the future. Growth projects will also require planned outages; however, these are not significant in the foreseeable future compared to renewal projects.

Table E.1 illustrates the linkage between each renewal fleet – and hence to expenditure – to the contributions to planned SAIDI and SAIFI. The data is illustrative of Aurora Energy’s renewal program with a total of 90,000 customers.

$$SAIFI \text{ Contribution} = \frac{\text{Outages per Unit} \times \# \text{ Customers Impacted} \times \text{Volume}}{90,000}$$

$$SAIDI \text{ Contribution} = SAIFI \times \text{Outage Duration}$$

The model shown in Table E.1 could be used for forecasting planned reliability if the input data is available or can reasonably be estimated. Alternatively, regression analysis can use past expenditure and volumes for each asset fleet, provided sufficient historical SAIDI and SAIFI data is available to identify the contributions from each fleet. Methods and engineering judgement can be combined to calibrate model input parameters.

Table E.1 shows the flow on effect of work planning and outage events. These are:

- outages per renewal unit and outage duration are a function of work planning and the time required to complete the work – the average and variance are reasonably predictable and consistent over time
- the # of customers impacted per outage over time will vary year on year depending on the balance of work between HV and LV systems following inspection programs – however, averaging over a 5 year period will tend to balance this year on year variance
- if more units of work can be bundled into one outage with multiple crews, SAIFI and SAIDI can be reduced

- pre-work planning and productivity improvements can reduce the outage duration – which will reduce SAIDI
- CAIDI, the ratio of SAIDI to SAIFI, will change depending on the mix of the renewal programs – increasing the crossarm replacement volume and reducing pole volumes will reduce CAIDI.

The parameters shown in the Table E.1 will vary year on year; for example, the outages per unit volume, the outage duration and the number of customer affected. However, as with the parameters for unplanned reliability, statistical distributions can be used to approximate the probability of such events affecting reliability. And so, the parameters *can* be modelled to predict future network performance with the same statistical distributions in each case (or the mean, which Aurora Energy has done).

**Table E.1: Relationship between planned outages and planned network reliability**

Fleet	Renewal unit	Outages per unit	Outage duration (Avg. min)	# customers impacted per outage (average)	Example volumes	SAIFI contribution (frequency)	SAIDI contribution (minutes)
Crossarms	#	0.1	90	70	3,000	0.30	21.0
Distribution Line	Km	0.8	180	70	30	0.02	3.4
Ground Mounted Switches	#	1	180	115	30	0.04	6.9
Poles	#	1	180	85	500	0.47	85.0
Pole Mounted Fuses	# Sets	1	150	70	50	0.04	5.8
Distribution Trans-formers	#	1	180	90	100	0.10	18.0
<b>Total</b>						<b>0.97</b>	<b>140.1</b>

### E.3 RELEVANT POLICIES AND PLANNING STANDARDS

Aurora Energy does not have any policies or standards specific to reliability modelling that we are aware.

### E.4 UNPLANNED RELIABILITY FORECAST (V5.11)

#### E.4.1 Information provided

Table E.2 lists the information that has been provided by Aurora Energy relevant to unplanned reliability modelling.

Table E.2: Information provided

Title	Reference	Date
QS00 - CPP Quality Standards Explanatory Memo	E-74	6 March 2020
QS02 - Unplanned Reliability Forecast	E-73	6 March 2020
Concept Explanation of unplanned Reliability Approach	V-135	27 March 2020
P03 - Reliability and Service Levels v1.1.pptx	V-134	27 March 2020
<b>Provided in response to our draft report</b>		
200513 Unplanned forecast memo	PR-69	14 May 2020
Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11	PR-68	14 May 2020

#### E.4.2 Model development and reviews

We reviewed the unplanned reliability modelling over two stages, beginning with the draft *QS02 - Unplanned Reliability Forecast* model in our draft report review, then an updated Aurora Energy version v5.11 reviewed in our final report.

Table E.3 below provides the changes to the forecast five-year review period for unplanned SAIDI and SAIFI compared to the DPP3 annualised limits. Aurora Energy proposes increasing the unplanned SAIDI and SAIFI DPP3 annualised targets. Aurora Energy's proposed unplanned SAIDI and SAIFI forecasts have increased since its first model.

Our review and analysis in the following sections is undertaken with respect to the *Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11* model and the accompanying *200513 Unplanned forecast memo*.

Table E.3: Unplanned SAIDI and SAIFI model Forecasts

Forecasts	Unplanned SAIDI (Normalised)	Unplanned SAIFI (Normalised)
Aurora Energy proposed targets QS02	94.93	1.80
Aurora Energy proposed targets v5.11	113.3	1.99
<b>DDP3 targets</b>	<b>63.4</b>	<b>1.169</b>
Aurora Energy proposed limits (caps)	146.29	2.51
<b>DPP3 limit (caps)</b>	<b>81.89</b>	<b>1.469</b>

### E.4.3 Reliability model and forecasts

#### E.4.4 Data integrity

##### Unplanned outage data

Outage data reported annually to the Commission was used in the unplanned model, including data from RY14 to RY19 for:

- number of faults
- average duration of the outages
- average number of ICPs impacted.

In the updated version, Aurora Energy included actual data for RY20. The earlier model (QS02) used only the historical data from RY08 to RY19. Actual unplanned SAIDI and SAIFI annual performance was also calculated using Aurora Energy’s outage statistics databases, which aligns with the reported data.

Datasets in the original QS02 model were segmented into the first nine outage cause categories listed in Table E.4. V5.11 was extended to use 13 outage categories, which we understand is because the four additional categories (shaded teal) have been applied since RY14.

**Table E.4: Outage causes included in the unplanned reliability model**

Outage causes		
Distribution cables	Ground mounted switchgear	Poles
Distribution conductors	Pole Mounted Fuses	Non-Asset related causes (such as adverse weather, third party causes, wildlife and unknown causes)
Distribution transformers	Pole Mounted Switches	Vegetation
Protection	Subtransmission conductors	Ground mounted switchgear
Other		

##### Asset health data

The unplanned model uses the AHI ratings (1–5) for each of the asset type causes dating from RY14 to RY26 based on the individual asset class renewal models.

##### Data quality

Although we have not audited the historical data, we have no reason to believe that it is materially inaccurate. Aurora Energy advised that it had corrected the data for errors previously reported to the Commission.

Outage cause data is likely to have some limitations. Aurora Energy indicated in the initial explanatory memo that:<sup>283</sup> ‘the quality of historical data creates difficulties in estimating the coefficients for the regression models’. Although recorded causes of outage events can be correlated between various causes –

<sup>283</sup> Aurora Energy, *QS00 - CPP Quality Standards Explanatory Memo*, 5 March 2020, p. 14.

such as weather and the reduced resilience of aging assets – this could be overcome by using different modelling approaches.

Spot checking of the asset health data inputs in the initial model showed several locations, which suggests that this data was unreliable. We did not review the data quality in detail in the new model, but these data issues appear to have been addressed.

Aurora Energy trained the regression model over four years of quarterly unplanned SAIFI and SAIDI data and contribution data for some asset categories. Although we have not reviewed it in detail, this should provide sufficient observations for the regression models (i.e. linear equations) to converge to reliable parameter estimates.

### E.4.5 Modelling methods

Aurora Energy’s unplanned model uses three different methods to forecast unplanned SAIFI:<sup>284</sup>

- **Multivariate regression** – this method was used to estimate parameters for distribution transformers, ground mounted switchgear, pole mounted fuses, pole mounted switches and poles.

This approach assumes that, as assets deteriorate, they have a higher probability of failure, and that assets in the same AHI category have a similar probability of failure. With the AHI being a proxy for probability of failure, the number of assets in each group is then related to the reliability performance of that asset category. These categories were considered to have sufficient data to reliably estimate model parameters.

The associated memo states that a Poisson distribution has been used in the modelling for each AHI population, which was done separately in Python to derive the probability of failures through the regression analysis process. This approach appears reasonable given the datasets available for each asset category.

- **Three-year averaging** – this method was used for five asset categories where sufficient asset health data was not available and the non-asset category (related to weather events and assisted failures) the health of an asset, Aurora Energy assessed alternative approaches for forecasting reliability. Aurora Energy used a simple three-year average using data from RY18 to RY20 to forecast unplanned SAIFI over RY21 to RY26. Aurora Energy considered that that period reflects the current level of network reliability.

We agree that this approach is reasonable given that the overall reliability of the network is not expected to change materially or otherwise become significantly more resilient to weather events over the CPP and review periods.

**Trend to target** – this method was used for the vegetation category, which covers outages caused by vegetation clashes with network assets. Aurora Energy states that these outages are not related to any specific asset’s condition. However, in general, new assets will be more resilient to smaller weather events than older assets and will contribute to lowering vegetation related events.

Aurora Energy has a specific vegetation strategy that sets out the objective and KPIs in terms of SAIDI and SAIFI contribution (20 minutes reduction by RY26). Aurora Energy has included adjustments for this in its forecast trend.

The historical trend (referring to Figure E.2) is that improving vegetation performance has seen a reduction in SAIFI but less measurable reduction in SAIDI. This trend will likely continue given the vegetation management strategy proposed and being implemented by Aurora Energy, which should see

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<sup>284</sup> Aurora Energy, Unplanned reliability forecast memo, 14 May 2020.

less impacts from smaller weather events, but less frequent and longer outages with larger weather events.

**Linear regression** – this method was used to determine unplanned SAIDI for each asset category using the SAIFI contribution forecasts. The unknown variables being the outage duration for each category. The coefficients of the regression SAIDI were calculated for all categories using historical SAIDI data from RY14 to RY20.

- **Normalisation** – Aurora Energy’s model initially forecasts pre-normalised unplanned SAIDI and SAIFI and then converts these to normalised values using scaling factors of:
  - 0.7296 for unplanned SAIDI
  - 0.924 for unplanned SAIFI.

Although based on historical data, these factors were hard coded in v5.11 of the unplanned reliability model and we could not validate the source of these calculations.

However, we observe that the average ratio of the historical pre-normalised SAIDI and SAIFI data from the DPP2 period (i.e. RY16 to RY20) to the DPP3 backcast normalised calculations over the same period give factors of 0.615 and 0.804 for SAIDI and SAIFI respectively. We are unsure why there is a difference between the normalisation factors used by Aurora Energy and the historical ratios we calculated.

We agree with the above approach in principle as it aligns with the linkage with unplanned SAIFI. However, we are unsure about the normalisations applied and recommend that the Commission investigate this further.

By using these various methods, Aurora Energy’s overall approach aims to model the fundamental asset reliability linkages to overall network reliability.

As a cross-check on Aurora Energy’s forecasts, we developed an alternative forecasting model during the draft report stage to establish our view of the expected network performance based on the program of renewal work. We did so because of concerns with Aurora Energy’s initial model. The revised model has corrected data errors and the methods – and this seems to have addressed most of our concerns with the initial model.

When reviewing the revised model, we used the updated data inputs and re-ran our alternate model. The forecasts from our re-run alternative model were then used to identify any discrepancies in the v5.11 model – which is detailed in section E.4.7.

#### E.4.6 Alternative forecasts

Our alternative model was used to validate Aurora Energy’s unplanned reliability forecasts prepared by Aurora Energy. This section first describes that alternative model before then comparing the forecasts.

##### Description

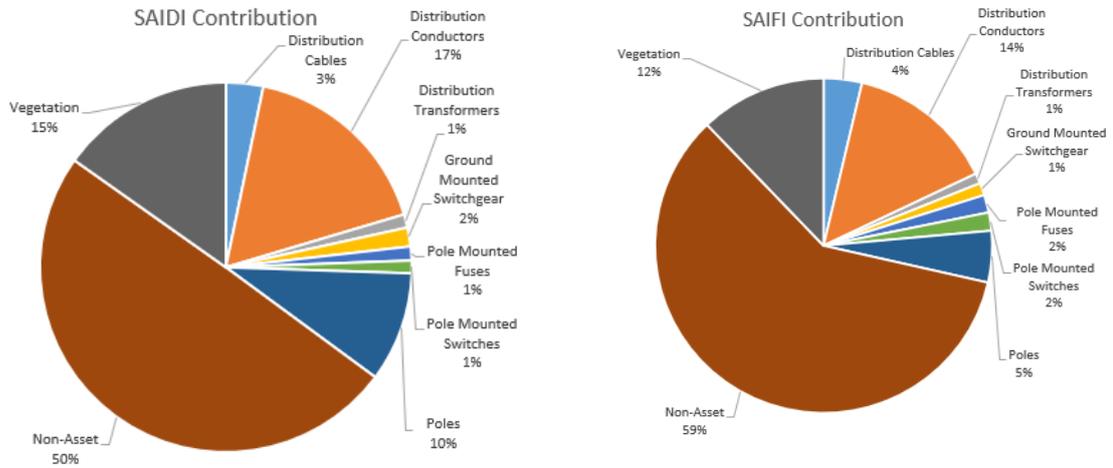
Our alternative model used the input data within the Aurora Energy model with the following components:

- **Normalised data used** – the alternative model uses the historical DPP3 backcast data as the baseline rather than the actual past outage data. The outliers removed through the normalisation process in the backcast data are assumed to be consistent with outliers that would be removed from future actual SAIDI and SAIFI data.
- **Survival data used** – the AHI data (past and forecast) for poles and distribution conductors is used in our alternative model, but instead of using regression derived parameters linked to AHI predictions (as

Aurora Energy's model does), our model used the survival data (probability of failure) directly for distribution conductors and poles (as provided by Aurora Energy in its renewal models). This should not materially affect the respective forecasts.

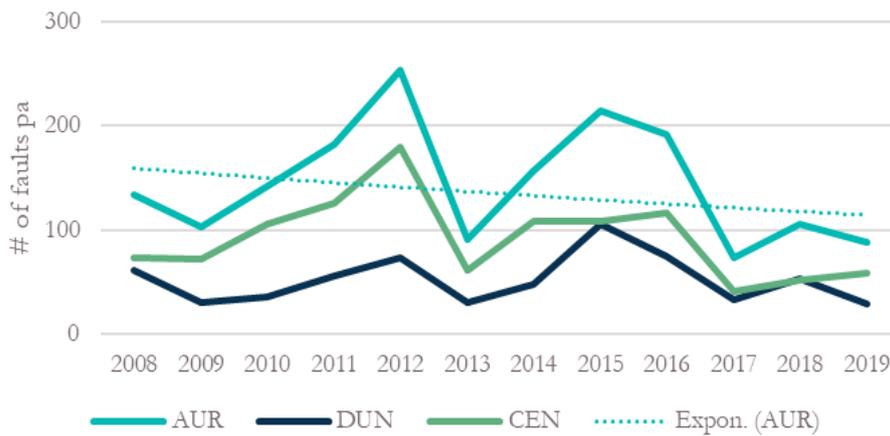
- **Lower contributing assets ignored** – the asset health of other asset fault causes has *not* been used in the alternative model. The four largest contributors are distribution conductors, poles, non-assets (e.g. weather) and vegetation. As shown in Figure E.3, these four account for 92% for unplanned SAIDI and 91% for unplanned SAIFI. Ignoring the lesser contributing assets allowed us to simplify the model for comparative purposes without materially affecting forecast accuracy.
- **Other aging assets contribution added** – a component for 'Other Aging Assets' was added to capture all of the other assets. These collectively include the other asset classes to allow for further general aging of the network, which will then begin to have an uplift effect.
- **Focus on CAIDI** – average actual data for unplanned SAIDI, SAIFI and CAIDI from RY14 to RY20 was used as the base case where the model's outputs were compared and calibrated to the average of the DPP3 backcast data in each case. Aurora Energy's updated model was revised and now also considers the linkage between unplanned SAIDI and SAIFI.
- **Model outputs tested** – the model was then tested against its ability to forecast past network performance compared to the actual DPP3 backcast data. The initial model provided by Aurora Energy used RY08 to RY19 historical data, so our initial alternative model calibrated the past SAIDI and SAIFI normalised data using the average from RY08 to RY19 as well. We adjusted our alternative model to calibrate only to the average of RY14 to RY20 data to be more consistent with Aurora Energy's revised model. The changing probability of failure of the assets from RY14 to RY20 is expected to explain the historical change in unplanned SAIDI and SAIFI compared to the average over the period. It should demonstrate a glide path through the centre of the historical datapoints (historical data demonstrating a normalised distribution except for the change in health of the network assets).
- **Vegetation strategy considered** – the model also accounts for Aurora Energy's proposed change to its vegetation management strategy, which was begun in recent years but still to be fully completed (i.e. implementing a five-year cycle). Vegetation related outages that do occur are expected to involve longer average durations, but overall, the number of events will decrease. This is evident from charting past # of faults and outage duration due to vegetation events (see Figure E.4 and Figure E.5).

Figure E.3: SAIDI vs SAIFI contribution by event causes<sup>285</sup>



Source: Aurora Energy, QS02 – Unplanned Reliability Forecast Data

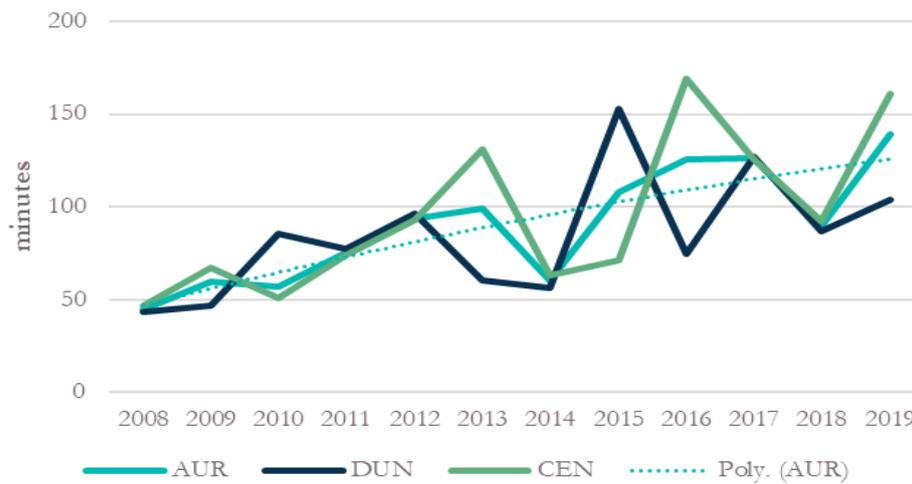
Figure E.4: Vegetation number of faults



Source: Aurora Energy, QS02 – Unplanned Reliability Forecast Data

<sup>285</sup> Contributions are prior to normalisation.

Figure E.5: Vegetation average outage



Source: Aurora Energy, QS02 – Unplanned Reliability Forecast Data

**Results**

Table E.5 shows that our alternative unplanned reliability forecasts are lower than those prepared by Aurora Energy (in the v5.11 model), but higher than the annualised DPP3 limits. We consider this comparison further in the next section.

Relatedly, Figure E.6 and Figure E.7 show that when our alternative model is backcast over the RY09 to RY20 period, it fits normalised actual data (i.e. ‘DPP3 backcast’) relatively well. The outcome shows a pronounced smoothing of the unplanned SAIDI forecast that does not follow the updated outcome for RY20.

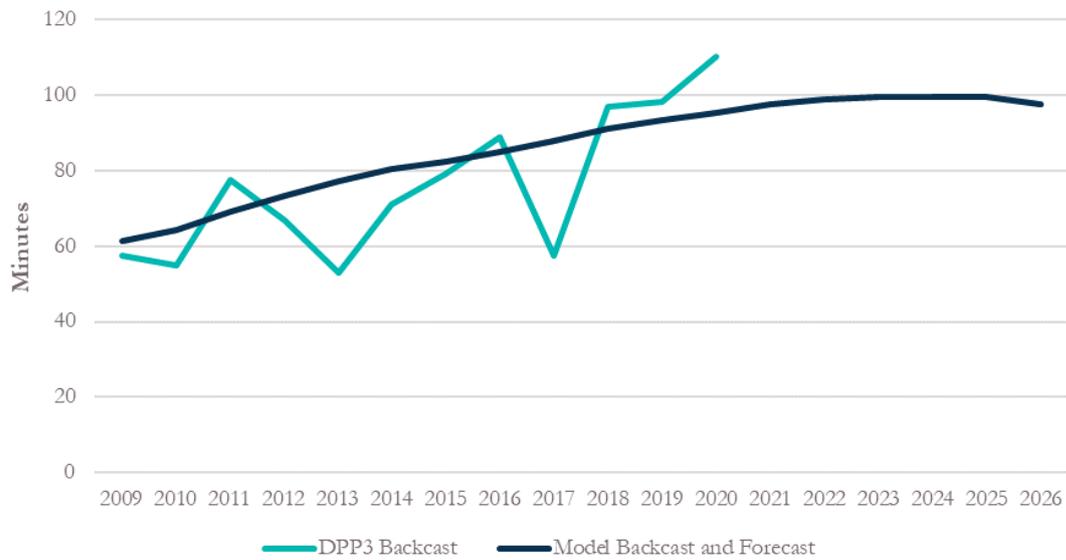
Table E.5: Aurora Energy and alternative model forecast comparison<sup>286</sup>

	Ry22	Ry23	Ry24	Ry25	Ry26
<b>SAIFI</b>					
Aurora Energy's forecast	1.94	1.99	1.98	1.93	1.84
Alternative forecast	1.62	1.61	1.62	1.62	1.61
DPP3 Limit	1.47	1.47	1.47	1.47	1.47
<b>SAIDI</b>					
Aurora Energy's forecast	111.77	113.34	111.96	110.17	106.20
Alternative forecast	96.84	95.51	96.75	97.20	97.26
DPP3 Limit	81.89	81.89	81.89	81.89	81.89
<b>CAIDI</b>					
Aurora Energy's forecast	58.98	57.67	56.82	56.60	57.09
Alternative forecast	59.91	59.37	59.98	60.28	60.26

Source: Aurora Energy, Farrierswier and GHD analysis.

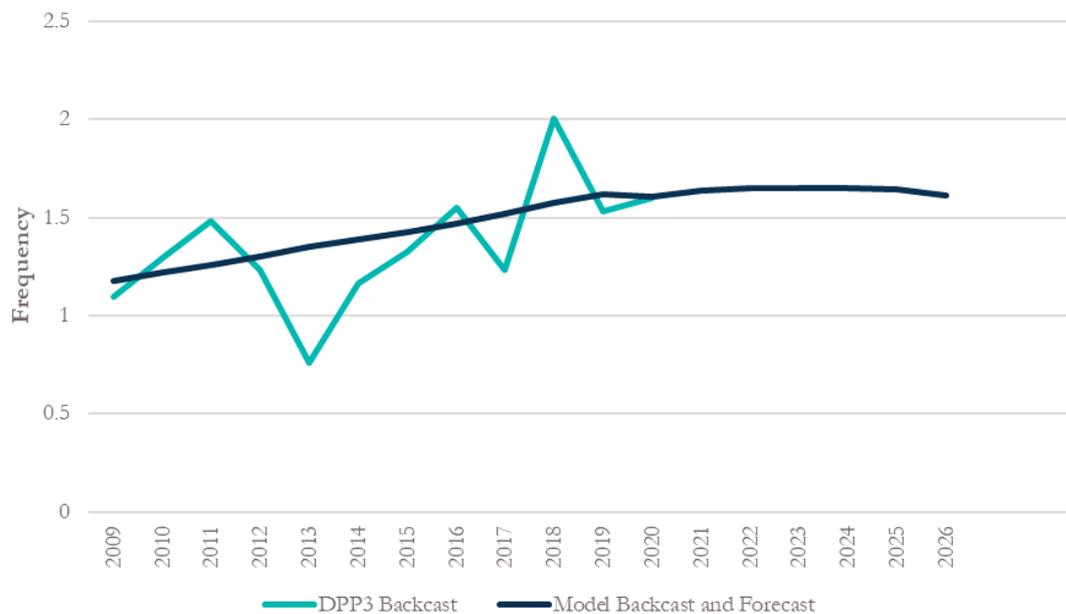
<sup>286</sup> Both sets of forecasts are intended to reflect the expenditure forecasts as proposed by Aurora Energy. If different expenditure forecasts are adopted by the Commission, then the reliability forecasts should also change accordingly.

Figure E.6: SAIDI forecast and backcast and forecast versus DPP3 backcast



Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure E.7: SAIFI forecast and backcast and forecasts versus DPP3 backcast



Source: Aurora Energy data. Farrierswier and GHD analysis.

### E.4.7 Aurora Energy forecasts

We reviewed the v5.11 unplanned model by addressing the areas with the Aurora Energy’s model identified in section E.4.5.

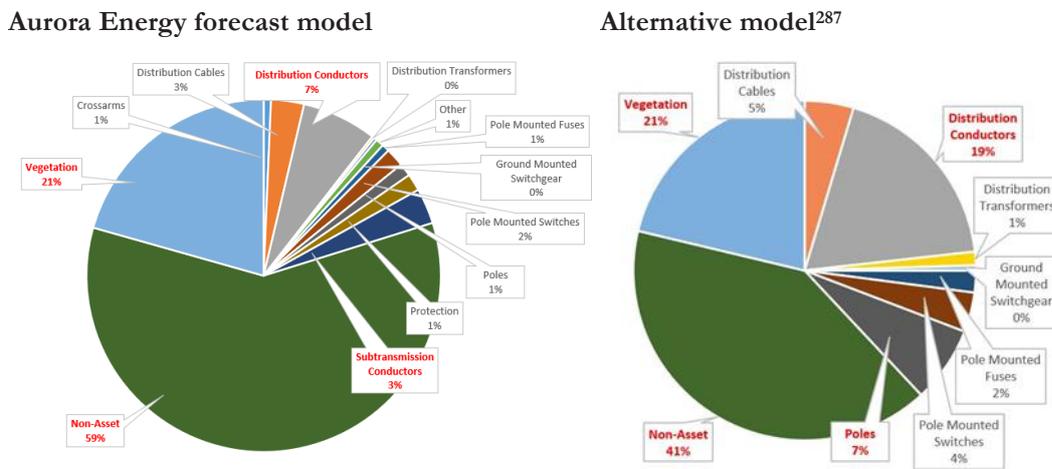
#### Unplanned SAIFI

We compared the unplanned SAIFI forecast contributions in Aurora Energy’s model to those obtained from data provided in the initial Aurora Energy model, which we had based our alternative model on. By

way of example, Figure E.8 provides the comparison for RY14 and shows that the asset contributions are similar except for distribution conductors and poles.

There is potential, therefore, that the contribution to improved network reliability due the past pole replacement program will be represented in the forecasts and the higher non-asset contribution will have a greater contribution in Aurora Energy’s updated model. During fact checking of our report, Aurora Energy advised that its revised model used a different method to attribute fleet to the outage records compared to its earlier modelling – and therefore compared to our alternative model. This illustrates to some extent a potential forecast difference that may arise due to the attributed cause of unplanned outage events.

Figure E.8: Asset contribution to unplanned SAIFI in RY14



Source: Aurora Energy data. Farrierswier and GHD analysis.

### Unplanned SAIDI

We compared the unplanned SAIDI forecast and backcast contributions with the parameters determined by the model for the highest contributing categories (except the inclusion of poles). Figure E.8 shows that the contributions each year with the non-asset category (weather) and the ‘other’ category following the higher SAIDI data years.<sup>288</sup> The asset reliability categories *do* show a lower fluctuation to weather events with some contribution to the high weather events.

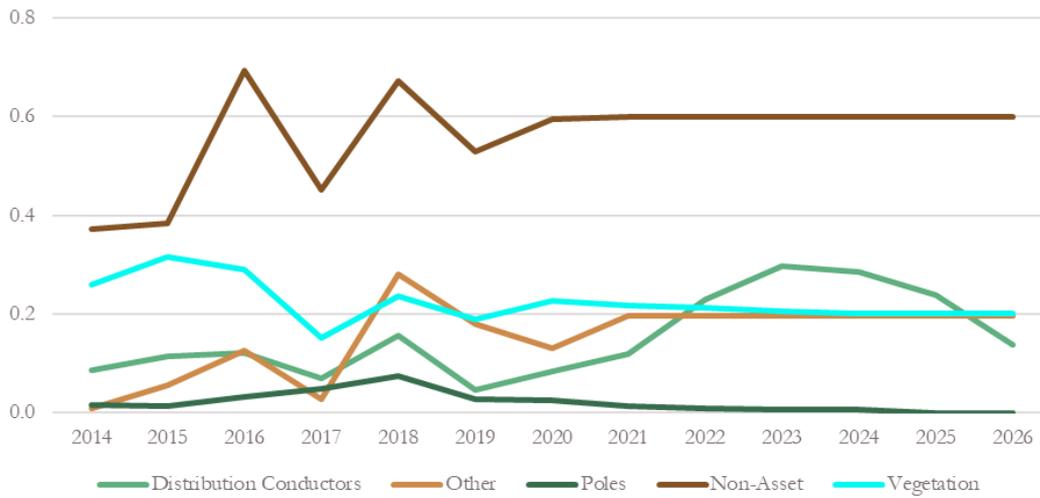
Based on this comparison, we observe that:

- the non-assets category contributes around 50% of the unplanned SAIDI forecast outcome – and so the forecast depends heavily on the estimated parameters for this category
- the large contribution shape for distribution conductors over the forecast period appears to be producing the same shape in the total unplanned SAIDI forecast – the shape is far more pronounced than would be based on the probability of failure changes predicted by our comparative asset renewal model and the lower contribution indicated in Aurora Energy’s model (refer Figure E.8).

<sup>287</sup> Data provided in *QS02 - Unplanned Reliability Forecast*.

<sup>288</sup> The contribution for the non-asset category has been halved to show with other assets on the graph.

Figure E.9: Model v5.11 asset category SAIFI contribution RY14<sup>289</sup>

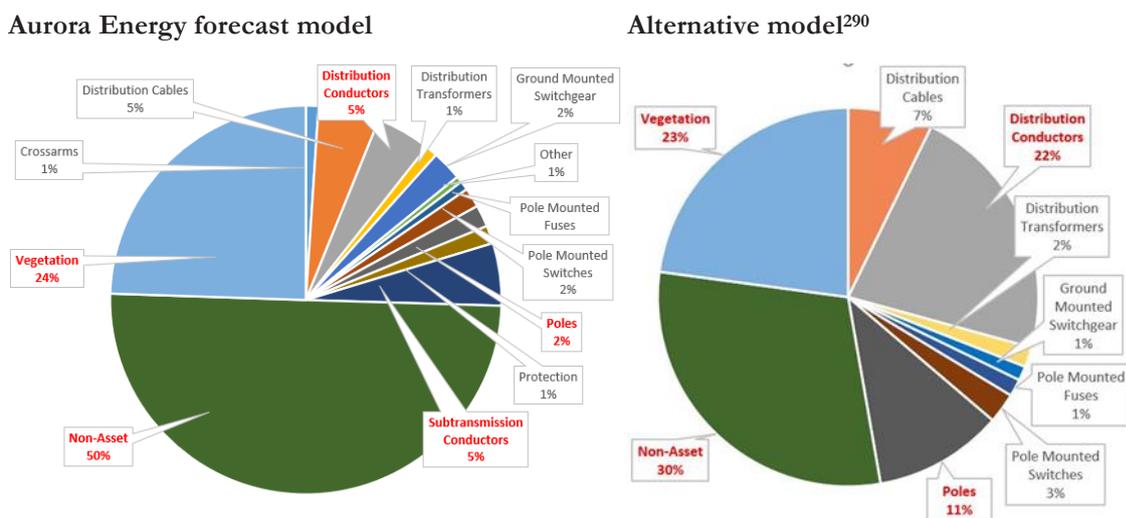


Source: Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11.

We also compared the forecast unplanned SAIDI contributions in Aurora Energy’s model to those obtained from data provided in the initial Aurora Energy model – which we had based our alternative model on. The pole and conductor fleet would provide a greater contribution in our alternative model based on the differences shown in Figure E.10.

As noted above for unplanned SAIFI, there is potential, therefore, that the contribution to improved network reliability due the past pole replacement program will be represented differently in the forecasts and the higher non-asset contribution will have a greater contribution in Aurora Energy’s updated model.

Figure E.10: Asset contribution to unplanned SAIDI in RY14



Source: Aurora Energy data. Farrierswier and GHD analysis.

<sup>289</sup> The contribution for the non-asset category has been halved to be shown on the graph.

<sup>290</sup> Data provided in *QS02 - Unplanned Reliability Forecast*.

### Normalisation factors

Aurora Energy uses normalisation factors to adjust its forecasts – which are based on pre-normalised historical data. We understand that the factors were based on data from the DPP2 period, giving a value of 0.924 to convert the forecast raw unplanned SAIFI data to a normalised forecast and 0.730 for unplanned SAIDI.

As mentioned earlier, these normalisation factors differ from the average ratio of:

- historical pre-normalised SAIFI and SAIDI for the DPP2 period (RY16 to RY20) to
- the same data normalised using the DPP3 method

for which we get factors of 0.804 and 0.615 for unplanned SAIFI and SAIDI respectively.

Given that Aurora Energy's unplanned reliability modelling is closely linked to the RY18 to RY20 period, the factors used to normalise the forecasts should be consistent (e.g. based on data from the same period). For instance, calculating the average ratios of historical actuals to the DPP3 backcast data over this same 3-year period gives ratios of 0.820 and 0.696 for SAIFI and SAIDI respectively. Although the normalisation factor for unplanned SAIDI is similar to that adopted by Aurora Energy, the factor for unplanned SAIFI is significantly lower. If a normalisation factor is too high, then the resulting normalised reliability forecast will be too high as well.

### Vegetation contribution to performance

As shown in Figure E.2, the historical trend is that improving vegetation performance has seen a reduction in unplanned SAIFI, but a less measurable reduction in unplanned SAIDI. In our view, unplanned SAIFI should see improvements owing to Aurora Energy's new vegetation management strategy, with less proportional improvement in unplanned SAIDI. These contribution effects will be mixed in with other changing asset contributions.

Our review above shows that the most significant difference in forecasts between Aurora Energy's model compared to our alternative model relates to how normalisation has been modelled or treated. Different contributions by assets appear to only be affecting the *shape* of the expected change in performance over the five-year period not the *level* – which is noteworthy because the shape does not materially affect how Aurora Energy's proposed targets and limits are set.

Table E.6 compares our alternative forecasts to Aurora Energy's – it does so by comparing our initial alternative forecasts (step 1), then those forecasts updated for more recent data (step 2), and then to Aurora Energy's forecast with the normalisation factor updated (step 3). The comparison suggests that Aurora Energy's unplanned SAIFI forecast is significantly overstated. After adjusting our alternative model with corrected data and adjusting Aurora Energy's model with more relevant normalisation factors, the variance between the models is reduced to just 3.3%. Applying the same approach to unplanned SAIDI, the variance is also within 10%, which we would accept as being within a reasonable margin of difference.

Table E.6: Aurora Energy and comparative forecast comparison<sup>291</sup>

	SAIDI	SAIFI	CAIDI
<b>Step 1. Aurora Energy forecasts compared to initial alternative model</b>			
Aurora Energy's forecast	110.69	1.94	57.20
Alternative forecast (initial)	97.93	1.59	59.91
% variance	13.0%	21.7%	-4.5%
<b>Step 2. Aurora Energy forecasts compared to data updates in the alternative model</b>			
Aurora Energy's forecast	110.69	1.94	57.20
Alternative forecast (data updated)	98.96	1.65	60.11
% variance	11.9%	17.3%	-4.8%
<b>Step 3. Aurora Energy model normalisation factors reduced to 0.82 and 0.70</b>			
Aurora Energy's adjusted forecast	106.14	1.70	62.28
Alternative forecast	98.96	1.65	60.11
% variance	7.3%	3.3%	3.6%

Source: Aurora Energy, Farrierswier and GHD analysis.

## E.4.8 Our finding

In our view, the unplanned SAIDI and SAIFI forecasts for the CPP and review periods are overstated. However – consistent with Aurora Energy's proposal – in our view the DPP3 limits for unplanned SAIDI and SAIFI appear too low based on the information that we have reviewed and further modelling we have done.

Our view is based on the following observations:

- Aurora Energy has used regression parameters for the non-asset category based on data from RY18 to RY20 – if Aurora Energy's pre-normalised unplanned SAIDI and SAIFI forecasts were normalised using the ratios of historical actual and DPP3 backcast data from the same period, then the normalised unplanned SAIDI and SAIFI forecasts will be lower and more closely match our alternative forecasts
- although we have identified some other areas within the model that could lead to forecast errors (discussed above), they do not appear to materially affect forecast accuracy
- our alternative unplanned SAIDI and SAIFI forecasts are:
  - lower than Aurora Energy's, but are consistent with those forecasts *if* the normalisation factors are adjusted to correct the inconsistency noted above<sup>292</sup>

<sup>291</sup> Average over the review period RY22 to RY26.

<sup>292</sup> Although our alternative forecasts remain lower than Aurora Energy's even when the inconsistency is removed, they fall within a reasonable range – and so appear consistent.

- higher than the DPP3 targets for unplanned SAIDI and SAIFI – assuming that the same approach is used to convert them in to limits, our forecasts support higher limits than those adopted in the DPP3 determination<sup>293</sup>
- Aurora Energy’s revised modelling approach generally follows the expected linkages between the causes of unplanned outages and network SAIDI and SAIFI performance.

As described above, we developed an alternative model using a simplified approach to test the unplanned reliability forecasts prepared by Aurora Energy. We used this alternative model to identify areas to investigate, but do not consider it appropriate to substitute it for the model that Aurora Energy has developed. If suitable corrections are made to Aurora Energy’s model to address the points raised above, then the unplanned SAIDI and SAIFI forecasts that that model produces may be more accurate than those produced by our alternate model.

Figure E.11 and Figure E.12 compare our alternative unplanned SAIDI and SAIFI forecasts (*IV Comparative Forecast*) to Aurora Energy’s (*Proposed Target* and *Adjusted Target*) and those in the DPP3 determination (*Annualised DPP Limit*).<sup>294</sup>

The adjusted forecast average over the review period are as follows:

- unplanned SAIDI forecast of 106.1 minutes – which is lower than Aurora Energy’s proposed forecast (110.7 minutes), but both higher than the Commission’s DPP3 limit of 81.89 minutes
- unplanned SAIFI forecast of 1.70 outages – which is considerably lower than Aurora Energy’s (1.94 outages)

but *both* are higher than the Commission’s DPP3 limit of 1.47 outages.

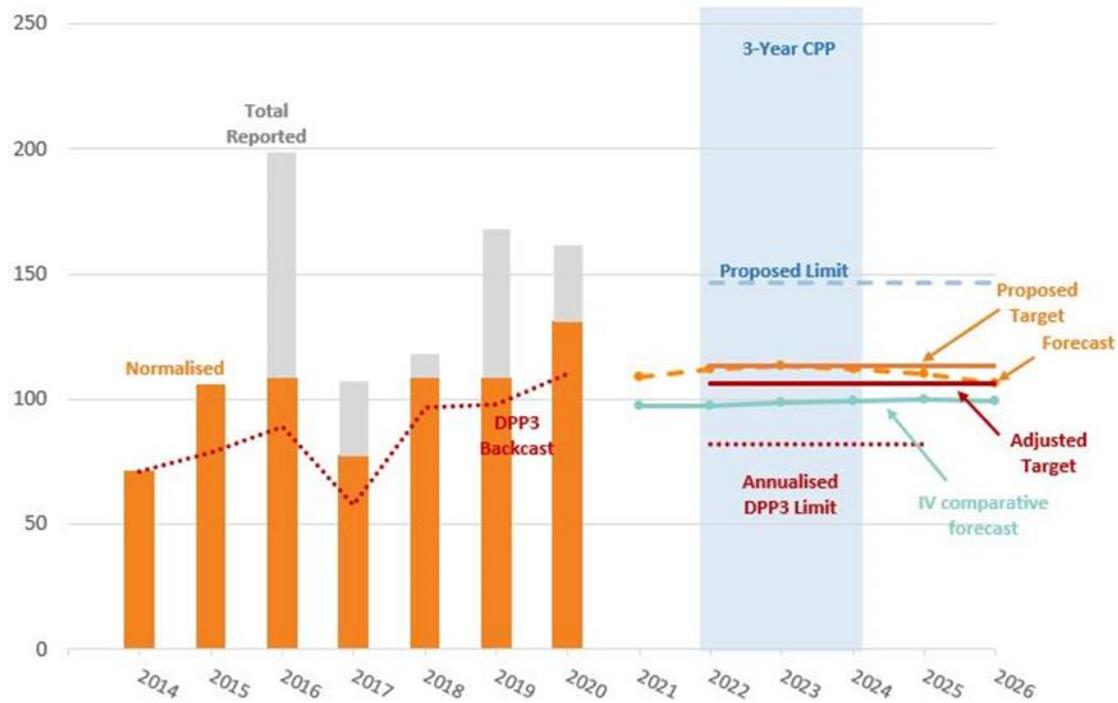
As shown, after adjusting Aurora Energy’s forecast to use revised normalisation factors, the forecasts more closely match the last three-year performance outcomes with a larger average CAIDI of 62.3 minutes. In effect, this gives a forecast *level* that is comparable to the last three years before it begins to improve towards the end of the period.

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<sup>293</sup> Our analysis indicates that Aurora Energy cannot meet the set DPP3 limits for unplanned SAIDI and SAIFI – and so it is not unreasonable to revise the targets and limits upwards. For instance, those limits could be calculated using the adjusted forecasts and the approach that Aurora Energy has used by applying a scaling factor to the above revised targets, consistent with the two standard deviations set in the DDP3 decision.

<sup>294</sup> In each figure, the ‘Proposed Target’ is the target proposed by Aurora Energy based on its forecast while the ‘Adjusted Target’ is that same forecast with the normalisation factor updated to be consistent with the data used to determine the parameters for the non-asset category etc.

Figure E.11: Historical and forecast unplanned SAIDI RY14-RY26



Source: Aurora Energy, QS02 – Unplanned Reliability Forecast Data. Farrierswier and GHD analysis.

Figure E.12: Historical and forecast unplanned SAIFI RY14-RY26



Source: Aurora Energy, QS02 – Unplanned Reliability Forecast Data. Farrierswier and GHD analysis.

## E.4.9 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast unplanned reliability was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may – in consultation with Aurora Energy – wish to consider whether the following areas should be revised in the modelling:

- whether the forecast normalisation factors should be adjusted to the ratio between pre-normalised historical SAIDI and SAIFI to the respective DPP3 backcast data
- whether the normalisation adjustment and the non-asset category regression parameters in Aurora Energy’s model should be determined consistently, with both estimated either over the RY14 to RY20 period or the RY18 to RY20 period (or some other period)<sup>295</sup>
- to what extent the relative contributions to historical unplanned reliability determined by the two different data sets used by Aurora Energy could be producing errors in the forecast and whether these are material to setting the targets.

## E.5 PLANNED RELIABILITY FORECAST (V5.01 AND V5.05)

### E.5.1 Information provided

Table E.7 presents the information that has been provided by Aurora Energy relevant to the planned reliability forecast modelling.

Our review has been based on a revised model ‘Aurora-model-forecast-planned-SAIDI-SAIFI v5.01.xlsx’ received on 6 May 2020. At the time of the draft report, our review was based on the provided ‘QS01 – Planned Reliability Forecast’ and ‘CPP Quality Standards – Memo’ documents. Since providing those documents, Aurora Energy has revised its forecast model and forecast planned SAIDI and SAIFI in this updated v5.01 the model – which addressed most of our draft findings.

We provided additional feedback to Aurora Energy on findings from our initial review of this v5.01 mode, after which Aurora Energy provided a revised model (v5.05). Although we have had an initial review of the revised model, we have not had sufficient time to form a view as to whether it fully addresses our findings. In this regard we have provided a table with comments for the Commission to consider in Table E.19 below as part of its review of the information.

**Table E.7: Information provided**

Title	Reference	Date
QS00 - CPP Quality Standards Explanatory Memo	E-74	6 March 2020
QS01 - Planned Reliability Forecast	E-72	6 March 2020
P03 - Reliability and Service Levels v1.1.pptx	V-134	27 March 2020
Planned-SAIDI-SAIFI model v4.8.xlsx (updated QS01)	V-130	27 March 2020

<sup>295</sup> The forecasts produced by Aurora Energy’s model are strongly influenced by the average unplanned SAIFI and SAIDI network performance over the RY18 to RY20 period. Our alternative forecasts are calibrated to the RY14 to RY20 period – and so are less influenced by performance over the shorter 3-year period. The question is whether the RY18 to RY20 outcome better reflects future performance compared to the RY14 to RY20 period.

Title	Reference	Date
Planned Methodology Technical v1.0.docx	V-132	27 March 2020
Modelling_Assumptions_Planned_v4.xlsx	V-131	27 March 2020
Category mapping from expenditure forecast to reliability forecast 27MAR.xlsx	V-136	27 March 2020
<b>Provided in response to our draft report</b>		
Aurora-model-forecast-planned-SAIDI-SAIFI v5.01	V-57	6 May 2020
Aurora-model-forecast-planned-SAIDI-SAIFI v5.05	PR-77	20 May 2020
Notes regarding revised planned reliability model	PR-78	20 May 2020
planned_v9.5.zip	PR-76	20 May 2020

## E.5.2 Model development and reviews

We reviewed the planned reliability modelling over three stages – beginning with the draft *QS01 -Planned Reliability Forecast* model in our draft report review, then v4.8 during the period of discussions with Aurora Energy following the issue of the draft report, and now v5.01 reviewed in our final report.

Table E.8 below provides the changes to the forecast 5-year review period for SAIDI and SAIFI compared to the DPP3 annualised limits. Given that the forecasts are below the limits, Aurora Energy is not proposing any changes to them. Initially, Aurora Energy was proposing an increase to the SAIFI DPP3 annualised limit as its planned SAIFI forecast was higher. However, in the final model the forecast has significantly been reduced.

The significant reduction of both planned SAIDI and SAIFI since the first model, now much less than the DPP3 annualised limits, raised the need to examine the reasons for these changes in this final report and a review to the same extent of the earlier model in the draft report. Our review and analysis in the following sections are made with respect to the final planned-SAIDI-SAIFI model v5.01.

Table E.8: Planned SAIDI and SAIFI model Forecasts

Forecasts	Planned SAIDI (De-Weighted)	Planned SAIFI (De-Weighted)
1. QS01 - Planned Reliability Forecast	129.0	1.45
2. planned-SAIDI-SAIFI model v4.8	161.5	1.29
3. planned-SAIDI-SAIFI model v5.01	67.9	0.53
<b>DPP3 annualised limit</b>	<b>196.0</b>	<b>1.11</b>

## E.5.3 Data Integrity

### Historical planned outage data

Outage data reported annually to the Commission was used in the unplanned model, including data from RY08 to RY19 for:

- raw SAIDI Figures
- raw SAIFI Figures

The final version (v5.01) has had the benefit of another two months of RY20 to include in the forecast.

#### **Other historical data**

- actual ICPs by region
- capital expenditure for asset fleet renewal categories (RY08 to RY20)
- historical volume replacements (RY08 to RY20).

#### **Historical contribution to planned SAIDI and SAIFI**

Aurora Energy determined that the following fleet categories contribute most to planned outages and reduced the model to addressing only these selected asset categories:

- crossarms
- distribution conductors
- fuses
- ground mounted switchgear
- poles
- transformers.

Aurora Energy calculates the contribution to historical planned SAIDI and SAIFI for these asset categories and this data then underpins two separate forecasting methods, one based on past and future expenditure and the other based on past and future renewal volumes.

#### **Forecasted data**

The modelling methods use the following forecasts as inputs in the model (RY21 to RY26):

- ICPs by region
- asset renewal forecast quantities for the selected fleet categories
- forecast capital expenditure for the selected fleet categories.<sup>296</sup>

#### **Data quality**

Although we have not audited the historical data, we have no reason to believe that it is materially inaccurate. Aurora Energy advised in *CPP Quality Standards – Memo* that it had corrected the data for errors previously reported to the Commission.

Based on our review:

- the historical expenditure and fleet renewal data entries did not appear to be outside of expected values
- the historical contribution to SAIDI and SAIFI by fleet category however was modelled in Python, and the results directly input to the reliability forecast model, hence we were unable to directly validate this data – although we have highlighted areas where issues may exist in this key part of the modelling process.

Aurora Energy states in the reliability model that the contribution data has been based on the number of customer-minutes generated by planned outages per fleet per quarter and generated by modelling

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<sup>296</sup> The initial models included maintenance and vegetation expenditure.

consumer-minutes and frequency data according to a Poisson distribution and using a generalized linear model.

This approach appears to be consistent with the linkage of planned outages to network planned SAIDI and SAIFI as described in our report in section 0.

#### E.5.4 Modelling methods

Aurora Energy’s forecasts planned SAIFI and SAIDI using two approaches:

1. linear regression based on past expenditure per fleet category
2. linear regression based on past renewal volumes.

These two methods have resulted in different forecasts as shown in Table E.9.

Table E.9: Planned SAIDI and SAIFI model Forecasts

Review Period (5 year average)	Expenditure Model	Renewal Volume Model
Planned SAIFI	0.66	0.53
Planned SAIDI	118.9	84.2
Planned CAIDI	180.2	158.9

#### Planned SAIFI

The initial CPP quality standards memo stated that:<sup>297</sup>

*The [planned] model adopts [for planned SAIDI] a linear relationship between expenditure and the frequency of planned outages. An efficiency adjustment was applied to future SAIFI to account for the reduction in the total annual number of outages as we improve the coordination of outages across fleet categories. The model assumes a 10% improvement in RY21, scaling to a 15% improvement by RY26.*

Aurora Energy initially selected an approach using total expenditure in a linear regression model to forecast planned SAIFI. In v5.01 *both* expenditure and unit volumes methods have been used based on each selected fleet category. This revised approach is appropriate and should produce more accurate forecasts than the approach used previously by Aurora Energy. Using both methods should enable areas of difference that could be used to further calibrate the model.

Key questions are whether or not:

- all expenditure or renewal volumes within each fleet category will result in the same outage requirements (in the past and into the future)
- bundling of work requirements will change the frequency of outages in the future, and to what extent
- minimal replacements and expenditure historically for some asset fleets (e.g. crossarms and conductors) will produce inaccurate forecasts.

<sup>297</sup> Aurora Energy, QS00 - CPP Quality Standards Explanatory Memo, 5 March 2020, p. 14.

## Planned SAIDI

The planned SAIDI forecast was initially based on the relationship between planned SAIDI and replacement volumes for each fleet category. The updated model now uses *both* the expenditure and the renewal volume methods.

This modelling approach seemed to be intuitively valid and the same as the current model. However, without being able to validate the inputs, some assumptions regarding unit volumes and the outage contributions are likely to be the reason for forecast differences between the expenditure and the renewal volume methods – and potentially to the accuracy of both model forecasts.

Referring to planned SAIDI, Aurora Energy noted in the quality standards explanatory memo that the:<sup>298</sup>

*challenge with the approach is the estimation of outage impacts relative to asset replacement volumes in circumstances where one outage corresponds with multiple fleets. We are also seeking business improvements in relation to outage management, which should change these relationships over time.*

## Planned CAIDI

Planned SAIDI and SAIFI forecasts are related by customer average interruption duration (i.e. planned CAIDI). However, this was originally not considered by Aurora Energy in the original QS01 model, as planned SAIDI and SAIFI were forecast separately using different input parameters and drivers. Namely, forecast capital expenditure for planned SAIFI and asset replacement volumes for planned SAIDI, despite both parameters obviously being related.

The new modelling methods inherently now produce reasonable forecasts for CAIDI. Aurora Energy used CAIDI to check on the validity of its forecasts.

The difference in CAIDI outcomes between the expenditure and the renewals model could be further investigated. We have provided further analysis in this regard in the review of the model. The key question is whether or not – and by how much – future outages will change average duration due to a different mix of asset replacement volumes compared to the past (mainly pole replacements).

## E.5.5 Model analysis

### E.5.5.1 Review of the Aurora Energy Model

We have analysed the forecasts produced by the two methods by looking at key ratios that we would expect to be constant over the review period representing the mean value of historical and statistically varying parameters.

For instance, we have considered the following historical and forecast data:

- Table E.10 shows the historical and forecast renewal volumes, while Table E.11 shows the historical and forecast expenditures.
- Table E.12 and Table E.13 show the ratios of the planned SAIDI and planned CAIDI contribution for each fleet to the renewal volumes. CAIDI is useful to analyse as it a direct measure of the expected average outage duration for each asset category.
- Table E.14 and Table E.15 show the ratio of the planned SAIDI and planned CAIDI contribution for each fleet to the renewal expenditure of each asset category.

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<sup>298</sup> Aurora Energy, QS00 - CPP Quality Standards Explanatory Memo, 5 March 2020, p. 14.

Based on our review of the data and forecast methods, we have some concerns with both the renewal volume and expenditure methods used by Aurora Energy.

However, as explained below, we agree with Aurora Energy that the annualised DPP3 limits for planned SAIDI and SAIFI remain appropriate for the CPP and review periods.

### Renewals volume method observations

Our concerns with the current renewals volume method as applied by Aurora Energy are:

- the forecast SAIFI and CAIDI ratios are not constant over the review period – which is not expected as ratios should be constant representing the mean values for each variable involved, including: # of outages, outage duration and # of customers impacted for a given volume of assets renewed in each category
- the reliability and accuracy of the historical data used in the regression analysis appears to be the reason for the mismatch – poles still show considerable variation even though poles were the main contributor to planned outages in the past<sup>299</sup>
- crossarm replacements historically have not been part of a separate program and were part of pole and conductor replacements – hence the expenditure may not be valid based on historical expenditure.

### Expenditure method observations

Our concerns with the expenditure model as applied by Aurora Energy:

- the forecast SAIFI and CAIDI ratios are relatively constant over the review period, except for a few exceptions, particularly the last two years for the pole category
- differences in CAIDI between the renewals model and the expenditure model should be reviewed – in particular, the outage duration for distribution conductors and for poles
- crossarm replacements historically have not been part of a separate program and were part of pole and conductor replacements, which is why they were bundled with other projects and may not be reliable for predicting future planned forecasts – however, the duration of 105 minutes seems reasonable and is consistent with the renewals model
- the reliability of the parameters determined by the regression analysis for the expenditure model would appear to be more reliable – however, the past asset category contribution to planned SAIFI is based on the same data as that determined by the renewals volumes method – hence, any common issues could be carried into both forecasting methods.

### Other observations

Other matters that appear to affect the current forecast:<sup>300</sup>

- **Pole Reinforcements** – expenditure on reinforced poles typically does not require an outage. Aurora Energy appears to have removed expenditure on poles in v5.05 of its planned reliability model – which, we have not reviewed in detail. However, it may not have removed the volume of poles renewed and this is likely still to be a large contributor to underestimating planned outages in the future (given that Aurora Energy is not continuing the reinforcement program).
- **RY18 bad weather year** – historically, the number of impacted customers varies and appears to be much higher in RY18 compared with other years. This one bad weather year in our modelling suggests

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<sup>299</sup> Aurora Energy staff noted that a known limitation with the input data is the number of poles that are replaced in each particular outage. In our view, the volume of poles that have been reinforced should be deleted from the pole replacements.

<sup>300</sup> Including historical data available in the *Modelling\_Assumptions\_Planned\_v4.xlsx*.

it alone contributed 22 minutes to the average planned SAIDI over a five-year period and 0.15 to the average planned SAIFI.

Examining why so many customers were impacted in RY18 could inform whether events in that year may also apply to planned outages forecast for the CPP and review periods. For example, the expenditure model does not include corrective maintenance expenditure, even though such corrective maintenance activities can affect customers, particularly in years where there is high storm damage such as occurred in RY18.

- **Crossarm renewal program** – a large change in crossarm renewal volumes occurs from RY21 onwards as part of a dedicated crossarm replacement program. A different outage duration for crossarms replacements will change the SAIFI and SAIDI outcomes compared to the past where poles were responsible for most of the expenditure and outage requirements.

This will depend significantly on the number of crossarms planned and renewed per planned outage event. For instance, five poles with multiple crews renewing crossarms within the one outage event will have a completely different outcome to renewing two crossarms on one pole with an outage required each time. Aurora Energy noted that it has allowed for five crossarms per outage in its v5.05 planned reliability model – which we have not reviewed in detail but is consistent with what we allowed for in our alternative model.

The crossarm replacements in the past have been part of other programs (for example, for RY20 the v5.01 model indicates 723 crossarms while MOD02 indicates 415 as part of the separate crossarm program).

- **RY20 observations** – although not yet submitted to the Commission, RY20 planned SAIDI and SAIFI observations appear to be unusually low compared to the past years. Aurora Energy staff noted that a known limitation with the input data is the number of poles that are replaced in each particular outage. In our view, the volume of poles that have been reinforced should be removed from the pole replacement data.

## Historical and forecast data

Table E.10: Historical and planned renewal volumes

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
FLEET	HISTORICAL					REVIEW PERIOD					
Crossarms	572	938	945	1602	723	1313	2408	3058	3058	3059	3059
Distribution Conductors	30	19	25	21	25	21	25	29	30	31	34
Ground Mounted Switchgear	5	4	-	-	37	42	42	43	43	42	25
Distribution Transformers	25	127	2	6	45	43	66	87	99	104	105
Fuse Mounted Switchgear	112	134	146	201	15	43	49	52	55	57	57
Poles	1098	2007	3155	1700	1030	1126	992	881	837	482	435

Source: Aurora Energy data. Farrierswier and GHD analysis.

Table E.11: Historical and planned renewal expenditure (\$'000)

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
FLEET	HISTORICAL					REVIEW PERIOD					
Crossarms	0	0	0	0	1141	3661	6629	8417	8420	8418	8425
Distribution Conductors	0	0	0	0	4172	4184	4692	5538	5968	6138	5727
Ground Mounted Switchgear	113	325	86	0	1223	3098	3098	3225	3120	3150	1875
Distribution Transformers	110	20	9	183	1359	1471	2146	2982	3600	3900	4029
Fuse Mounted Switchgear	39	374	174	706	75	215	245	260	275	285	285
Poles	3879	8209	41156	26990	14198	14352	12780	11472	10908	6660	6048

Source: Aurora Energy data. Farrierswier and GHD analysis.

Table E.12: Planned SAIDI contribution – per unit volume

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL					THE REVIEW PERIOD					
Crossarms/3000	0.09	0.20	-	0.50	15.60	0.10	1.39	14.31	14.11	13.97	13.78
Distribution Conductors/30km	3.9	2.5	6.0	5.5	5.2	10.9	11.6	15.3	16.8	17.9	21.1
Ground Mounted Switchgear/30	2.7	0.9	-	-	12.7	3.2	2.2	2.2	2.1	3.0	5.0
Distribution Transformers/100	30.4	0.9	292.4	146.6	14.5	2.4	1.2	0.8	0.6	0.6	0.6
Fuse Mounted Switchgear/10	0.3	0.5	0.2	0.5	3.6	0.2	0.2	0.2	0.2	0.2	0.2
Poles/500	4.0	11.3	41.4	36.2	35.3	63.1	47.9	38.5	34.4	17.9	17.5

Source: Aurora Energy data. Farrierswier and GHD analysis.

Table E.13: Planned CAIDI contribution – per unit volume

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL					THE REVIEW PERIOD					
Crossarms	15	64		295	106	154	120	99	99	99	99
Distribution Conductors	116	72	72	292	282	85	97	134	150	165	201

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL						THE REVIEW PERIOD				
Ground Mounted Switchgear	17	65			134	171	221	221	221	171	171
Distribution Transformers	263	162	322	304	236	263	248	238	237	237	239
Fuse Mounted Switchgear	6	11	27	24	220	163	106	76	60	29	28
Poles	154	223	186	259	235	174	180	185	188	222	224

Source: Aurora Energy data. Farrierswier and GHD analysis.

Table E.14: Planned SAIDI contribution – per unit expenditure

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL						THE REVIEW PERIOD				
Crossarms/\$8500					28.0	27.6	27.5	27.4	27.4	27.4	27.4
Distribution Conductors/\$4500					4.7	4.7	4.3	3.8	3.6	3.5	3.7
Ground Mounted Switchgear/\$400	1.6	0.1	25.6		5.1	4.3	4.3	4.3	4.3	4.3	4.5
Distribution Transformers/\$4000	276.6	239.1	2599.1	192.3	19.2	18.5	13.8	10.8	9.5	9.0	8.9
Fuse Mounted Switchgear/\$300	23.6	5.2	5.5	3.9	21.7	6.9	6.4	6.2	6.0	5.8	5.8
Poles/\$6000	13.7	33.0	38.1	27.3	30.8	30.7	29.8	28.8	28.4	22.2	20.6

Source: Aurora Energy data. Farrierswier and GHD analysis.

Table E.15: Planned CAIDI contribution – per unit expenditure

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL						THE REVIEW PERIOD				
Crossarms					106	106	106	105	105	105	105
Distribution Conductors					282	283	341	501	647	727	557
Ground Mounted Switchgear	17	65			134	237	237	241	237	238	187

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fleet	HISTORICAL					THE REVIEW PERIOD					
Distribution Transformers	263	162	322	304	236	230	211	196	188	184	182
Fuse Mounted Switchgear	62	12	20	5	38	17	15	13	13	9	9
Poles	154	233	186	259	235	216	221	226	229	293	326

Source: Aurora Energy data. Farrierswier and GHD analysis.

### E.5.5.2 Alternative forecasts

As a cross-check against Aurora Energy’s forecasts, we developed a separate planned reliability model – similar to the renewal volume method but based on estimates for the variables defined in section 0.

#### Description

In our alternative model, we:

- used outage durations for each of the asset categories (CAIDI) by calibrating the model to the actual past network planned outage data (actual CAIDI) – this produced outage durations slightly lower than the Aurora Energy models
- adjusted for the expected pole renewals in the past to match actual number of outages in total for those years<sup>301</sup>
- fitted the model to the RY16 to RY20 years – being the period we had data for – to establish the predicted number of impacted customers per asset category to arrive at the actual planned SAIFI outcomes
- used the determined asset category average outage durations and average impacted customers to forecast future planned SAIDI and SAIFI based on the forecast asset renewal volumes
- used the past averages for the number of impacted customers, with and without the RY18 bad weather year to estimate the impact to forecasts over a five year period – as indicated above, bad weather contributions of 22 minutes could contribute to the average planned SAIDI over a five year period and 0.15 to the average planned SAIFI over a five year period.

Aurora Energy adjusts its raw planned SAIDI and SAIFI forecasts down for potential efficiencies:

- **Outage notification** – the planned SAIDI forecast includes an ‘outage notification improvement wedge’, i.e. transitioning from 20% to 80% of outages being notified and delivered to plan by RY24
- **Outage coordination** – the SAIFI forecast includes an outage coordination/efficiency wedge, i.e. a 10% reduction in planned outages to deliver the same work by RY24.

We have included these same adjustments in our alternative forecasts. In our view, the proposed adjustments appear appropriate.

<sup>301</sup> Data available within the *Modelling Assumptions Planned v4*.

## Results

As shown in Table E.16 and Table E.17 – and Figure E.13 and Figure E.14 – the alternative model produces planned SAIDI and SAIFI forecasts that are higher than that forecast by Aurora Energy, but are lower than the annualised DPP3 limits.<sup>302</sup>

Figure E.15 shows the likely effect of correcting the historical data to remove expenditure (and volumes) for pole reinforcements where no outages were required. This figure shows that the expenditure model regression analysis will produce lower planned SAIFI per unit of expenditure if the expenditure on pole reinforcements is included. If this expenditure is removed, then a different linear best fit line will move the forecasted years higher.

The high planned SAIFI in RY18 was a bad weather year and a combination of removing expenditure for pole reinforcements is likely balanced by the expenditure that should be added for corrective maintenance. We expect a similar outcome would occur in the linear regression in the renewal volumes method if the volumes associated with pole reinforcements were removed.

**Table E.16: Planned SAIDI Forecasts**

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MODEL	HISTORICAL PERIOD					REVIEW PERIOD					
Aurora Energy expenditure model	35.4	62.5	290.0	154.3	111.4	134.8	135.4	135.1	131.1	104.8	88.1
Aurora Energy renewal model	23.9	54.6	280.6	150.3	108.5	156.5	111.0	101.9	93.4	55.8	59.0
Alternative model	38.2	59.8	287.3	126.9	107.3	173.2	165.8	168.3	165.4	151.7	108.9
Actual historical	35.43	62.47	290.01	154.30	111.42						

Source: Aurora Energy data. Farrierswier and GHD analysis.

**Table E.17: Planned SAIFI Forecasts**

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MODEL	HISTORICAL PERIOD					REVIEW PERIOD					
Aurora Energy expenditure model	0.23	0.36	1.71	0.73	0.61	0.68	0.72	0.74	0.72	0.58	0.54
Aurora Energy renewal model	0.16	0.28	1.64	0.71	0.56	0.95	0.67	0.65	0.59	0.37	0.37
Alternative model	0.23	0.36	1.71	0.74	0.63	1.12	1.16	1.11	1.09	1.05	0.75

<sup>302</sup> Aurora Energy has averaged the two model outputs to provide their forecast 'Forecast Baseline'. Figure E.13 and Figure E.14 have been reproduced from Aurora Energy's model with the inclusion of the expenditure model baseline forecast alone and our 'TV model' baseline for comparison.

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
MODEL	HISTORICAL PERIOD					REVIEW PERIOD					
Actual historical	0.23	0.36	1.71	0.73	0.61						

Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure E.13: Network planned SAIDI



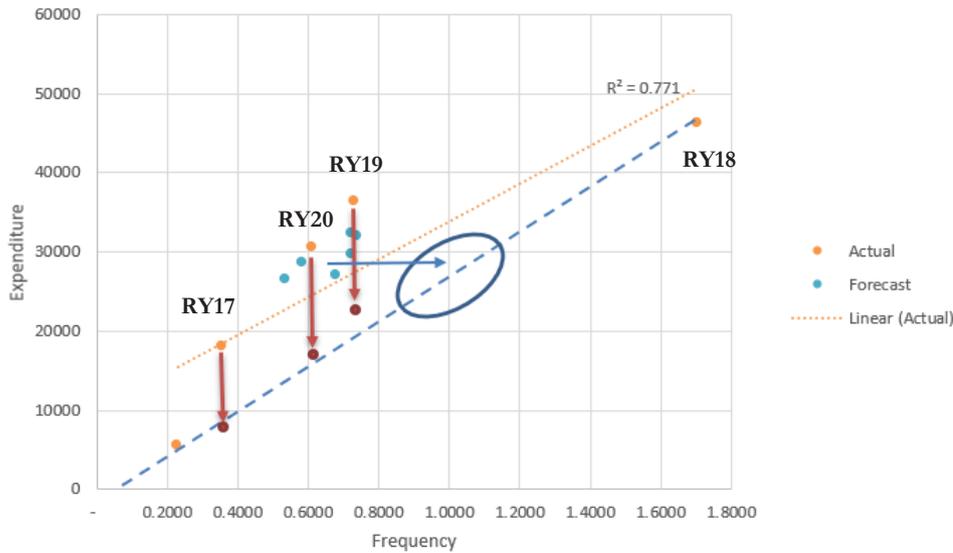
Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure E.14: Network planned SAIFI



Source: Aurora Energy data. Farrierswier and GHD analysis.

Figure E.15: Adjustment to SAIFI for historical pole reinforcement expenditure<sup>303</sup>



Source: Aurora Energy data. Farrierswier and GHD analysis.

### E.5.6 Our finding

In our view, the approach to forecasting planned SAIDI and SAIFI in the ‘*planned-SAIDI-SAIFI model v5.01*’ model is valid, but was not producing valid results due to input data errors based on our modelling and corrections to input data. Based on this analysis, though, the annualised DPP3 planned reliability limits still appear appropriate without need for change.

Our view is based on the following observations:

- expenditure and work programs have increased and will change significantly compared to the past – and as a result it is difficult to use econometric models alone based on historical data to confidently predict future outcomes from projected planned work
- Aurora Energy has advanced its model since we reviewed it at the draft report stage, addressing our draft findings – for instance, checking CAIDI to validate the SAIDI and SAIFI forecasts
- the model considers a broad range of impacts on reliability, including potential efficiency improvements – which appears appropriate
- the model, however, does not appear to recognise that historical pole renewal expenditure included pole reinforcements that do not cause outages – which are likely to be causing the model to *understate* planned reliability outcomes
- *if* the planned work goes ahead, then our alternative model – which we developed as a cross-check – suggests that actual planned SAIDI and SAIFI over the CPP and review periods will likely be higher than Aurora Energy’s forecasts
- even so, both our alternative forecasts and those prepared by Aurora Energy indicate that planned SAIDI and SAIFI will not breach the annualised DPP3 planned limits over the CPP or review periods.

Table E.18 compares the planned SAIDI and SAIFI forecasts for the CPP period, both raw and de-weighted.

<sup>303</sup> RY18 (highest expenditure year) included a large quantity of pole reinforcements. However, it was also a year of high storm activity.

Table E.18: Comparison of forecasts for the CPP period (v5.01)

Measure	Aurora Energy	Alternative model
Planned SAIDI (raw)	CPP period: 353.9 minutes Per year: 118.0 minutes	CPP period: 499.5 minutes Per year: 166.5 minutes
Planned SAIDI (de-weighted)	CPP period: 245.3 minutes Per year: 81.8 minutes	CPP period: 345.5 minutes Per year: 115.2 minutes
Planned SAIFI	Per year: 0.63 outages	Per year: 1.03 outages

Source: Aurora Energy. Farrierswier and GHD analysis.

- (b) Both sets of forecasts are intended to reflect the expenditure forecasts as proposed by Aurora Energy. If different expenditure forecasts are adopted by the Commission, then the reliability forecasts should also change accordingly.
- (c) The Aurora Energy forecasts are those as reflected in the planned and unplanned models that underpin the latest models reviewed. Aurora Energy may update the forecasts subsequent to our review of these models.

Aurora Energy has responded to some of our findings on 20 May 2020 as shown in the following Table E.19 and provided an updated v5.05 model. In the time available, we did not review the updated model in full. However, we have considered Aurora Energy's responses in the right hand column of the table. Although further consideration of these *may* lead to changes to our findings above, we agree with Aurora Energy that there does not appear to be a need to vary the DPP3 quality standard limits for planned reliability.

Table E.19: Clarification from Aurora Energy on planned reliability forecasts

Verifier's observation (on v5.01)	Aurora Comment	Our further Comments (on v5.05)
<p>The modelling <i>approaches</i> used for each of planned SAIDI and SAIFI look reasonable, however, we would expect the forecasts for each to be closer together – the fact that they are not suggests that there may be some issue with the <i>inputs</i> to the modelling</p>	<p>We could not establish a discrepancy/separation of SAIDI and SAIFI pre normalisation. The relationship between SAIDI and SAIFI is strong. There is a business notification efficiency factor applied to the SAIDI forecast and a work bundling factor applied for SAIFI. Planned SAIFI is no longer subject to normalisation under the DPP3 regime, i.e. the new notification factor does not apply to SAIFI and hence to post normalisation values diverge.</p>	<p>Our concern was related to the different forecasts produced by the expenditure method and the renewal volumes method and not with respect to the planned SAIDI and SAIFI relationships.</p> <p>This concerns remains with the latest v5.05 model.</p>
<p>Further, the ratio of the forecasted SAIFI and CAIDI contributions to expenditure and to renewal volumes should be relatively constant over each year in the forecasted period representing the mean values for each variable involved – however, this is not the case and is more pronounced with the renewal volumes method.</p>	<p>We have looked into the ratio between the SAIDI and expenditure per fleet and found it is stable for all asset portfolios over the period. Please clarify your concern.</p>	<p>Our report does suggest that the ratio for expenditure and SAIDI was reasonably consistent as Aurora has noted.</p> <p>However, this is different with the renewal model. Planned SAIDI over the RY21 to RY26 forecast data showed a standard deviation of 76% to the average when it should be 0%. Hence, the lessor confidence in the forecasts produced by the renewal volume methods.</p>
<p>We understand that expenditure on reinforced poles typically do not require an outage. Our analysis suggests that the volume of poles renewed historically included the number of reinforced poles (<i>Modelling_Assumptions_Planned_v4</i>). Recognising this corrects the mismatch between actual outage and the number of poles renewed in the data sets. If so, this is likely to be the biggest</p>	<p>We agree with this observation and appreciate the information.</p> <p>After further analysis we managed to extract the expenditure on pole reinforcement from the inputs into the planned model.</p>	<p>The expenditure for reinforced poles is needed to be removed from historical expenditure for both planned SAIFI and SAIDI forecasts. The data on expenditure remaining in v5.05 still shows the same</p>

Verifier's observation (on v5.01)	Aurora Comment	Our further Comments (on v5.05)
<p>contributor to underestimating planned outages in the future, given that Aurora Energy is not continuing the reinforcement program. If our understanding is correct, then the volumes and expenditure for reinforced poles should be removed from the historical data to improve forecast accuracy, which will likely lift the forecasts.</p>	<p>The updated forecast (a slight increase) is presented in the latest version -Planned v5.05, which does not change our proposed DDP3 level quality standard for planned SAIDI and SAIFI.</p>	<p>expenditure and the calculation for planned SAIDI is based on the original expenditure.</p> <p>We could not confirm if the Python model removed the expenditure. Although the updates lead to an increase in the forecast planned SAIFI, there does not appear to be an increased contribution to the historical planned SAIFI contribution – which we would expect.</p> <p>Our view is that outages related to the pole program will represent 70% to 90% of the contribution to planned SAIFI whereas Aurora's revised model v5.05 is still only showing 40% to 50% over RY21 to RY24.</p> <p>Volumes for reinforced poles also need to be subtracted from historical data. Historical planned SAIFI contributions in both models appear to depend on the regression of historical replacement volumes – hence, this will affect forecasts for both methods</p>
<p>Crossarm replacements historically have not been part of a separate program and were part of pole and conductor replacements – hence, using regression analysis based on historical expenditure and renewal volumes is <i>potentially</i> not reliable. The crossarm renewal program volumes occurs from RY21 onwards as</p>	<p>We recognise that the expenditure model for crossarms has limitations due to the sparsity of historical data (i.e. only RY20 data). In order to strengthen the crossarm forecast, we revisited Model 2, and we have incorporated an assumed ratio of 5:1</p>	<p>A further review of our alternative model indicates an average ratio of 5:1 for units per outage for crossarms will have a minimal impact on the contribution to SAIFI, whereas a ratio</p>

Verifier's observation (on v5.01)	Aurora Comment	Our further Comments (on v5.05)
<p>part of a dedicated crossarm replacement program. A different outage duration for crossarms replacements will change the SAIFI and SAIDI outcomes compared to the past where poles were responsible for the majority of the expenditure and outage requirements. The actual effect, however, will depend significantly on the number of crossarms planned and renewed <i>per planned outage event</i>. The future number of planned outages (hence SAIFI) is very sensitive to this factor. It is not clear to us what assumption is included in the planned reliability model as to how many crossarms can be replaced per outage (on average). If 10 is the answer, then that appears appropriate. If not, then that may be creating a data input issue, potentially contributing to lower forecasts.</p>	<p>for units per outage for crossarms to poles. This is supported by the assumption of replacing three poles per day, at 1.7 crossarms per pole. The impact on Model 2 was a slight increase in both SAIDI and SAIFI over the CPP period, but still less in magnitude compared to Model 1. Given the output of model 1 has a linkage to recent crossarm replacement work, we consider the output from Model 1 has value as a forecast methodology and therefore we continue to average with Model 2 in the resultant forecast.</p> <p>Implementing this change provides us with greater confidence that the expected impact from increased crossarm replacements is appropriate, and we are satisfied that performance will remain beneath the DPP3 quality standard during the forecast period.</p>	<p>below this will increase planned SAIFI significantly.</p> <p>Our alternative model was based on a ratio of 8.5:1 and making a minimal impact to overall planned SAIFI.</p>

### E.5.7 Completeness and key issues for the Commission

The information provided by Aurora Energy on forecast planned reliability was sufficient for us to undertake our verification. We are not aware of any information that we consider was omitted by Aurora Energy.

When undertaking its own assessment of the information, the Commission may – in consultation with Aurora Energy – wish to consider whether the following areas should be revised in the modelling:

- whether the regression analysis should be updated to so that the ratios of forecast planned SAIFI and CAIDI contributions by category to *both* expenditure and renewal volumes are constant over the forecast period (see Table E.13)
- whether historical outage, expenditure, and volume data needs to be adjusted to account for pole reinforcement that did not require outages<sup>304</sup>
- whether the historical outage and expenditure data should be adjusted to recognise that crossarm renewals were not previously part of a separate program – note that this matter appears to be resolved in v5.05
- whether corrective maintenance should be included in the regression models, which can impact how high storm damage in RY18 is reflected in the forecasts.

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<sup>304</sup> Although not reviewed in detail, it appears that v5.05 of Aurora Energy’s planned reliability model adjusts expenditure data for pole reinforcements, but not the volume data. A more thorough review of the revised model may prove our initial assessment incorrect.

# Appendix F Network risk

## F.1 OVERVIEW

This appendix considers how Aurora Energy proposes to address the network risks identified by WSP in its state of the network review. As well as assessing how proposed asset fleet strategies and expenditure forecasts address those risks, we have also compared Aurora Energy's maintenance intervals to those adopted by other New Zealand EDBs and to GHD's experience working with Australian EDBs.

We find that:

- WSP used a more qualitative approach to assess asset volumes at high risk within the different asset fleets whereas – with the passage of time and improved data – Aurora Energy has developed models aimed at more accurately and quantitatively determining replacement volumes
- Aurora Energy's proposed asset strategies for the asset fleets that we reviewed appear reasonable given the existing asset management system maturity, data availability, and deliverability constraints – although risks for some asset fleets are presently high, the proposed strategies appear to adequately address these
- Aurora Energy has generally nominated inspection, testing and maintenance cycles that are comparable to peers in NZ and Australia, and therefore implicitly manage the maintenance of its assets at similar risk levels to its peers
- Although Aurora Energy has only explicitly considered the ALARP principle when forecasting expenditure for some asset fleets (e.g. zone substation related), the age and condition based modelling used for other fleets are based on assumptions that are consistent with those adopted by other NZ EDBs – suggesting that the forecasts themselves are consistent with the principle, even if the approach used to generate them may not consider it directly.

As detailed below (e.g. Table F.3 and section F.2.5.2), we also identified further improvements to Aurora Energy's risk assessment and mitigation activities that should be considered over the CPP and review periods. One in particular is that need to implement an effective defect grading system that can be used to prioritise defect maintenance activities.

## F.2 NETWORK RISK

### F.2.1 Background

In its 2018 report, WSP independently assessed Aurora Energy's electricity network infrastructure against the following perspectives:<sup>305</sup>

- **Resilience** – the ability of the network to withstand or recover from high impact, but very low frequency, events such as earthquakes
- **Security** – whether the electricity network topology provides appropriate capabilities, such as capacity, redundancy and switching capability, to maintain normal supply to consumers
- **Performance** – an indication of which assets and areas of the network pose the greatest risk to public safety, reliability of supply and the environment based on historical rates and durations of asset outages

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<sup>305</sup> WSP, *Independent review of electricity networks*, final report, November 2018, p. viii.

- **Network risk** – the combination of the probability that assets may fail and the consequence of the impact to public safety, reliability of supply or the environment.

This appendix focuses only on the network risk perspective assessed by WSP.

Aurora Energy has generally accepted the findings of WSP’s network risk assessment and leveraged off these to develop its first AMP after its separation from Delta. The underlying analysis – data collection, corroboration, cleaning, assumptions and inference – performed by WSP for its assessment provided Aurora Energy the starting point to perform its own asset data analytics. It formed the basis for developing and progressing its respective risk assessments and strategies for its asset fleets.

With the passage of time from 2018 and as more asset data is captured and/or cleaned resulting from its ongoing operational and capital activities, Aurora Energy has refined its understanding of the status of its asset portfolio. This has resulted in changes to some elements of risk assessment methodology in some asset fleets and the way it informs the ongoing and renewal expenditure forecast. This asset management journey since 2018 has to be appreciated, along with the present day asset management system limitations, to understand how Aurora Energy’s asset strategies have evolved and how it plans to respond to the network risks identified by WSP.

Before comparing our findings in Appendix D with the WSP report findings, we first discuss the approaches used by WSP’s assess the network risk levels across various fleets and how Aurora Energy has adapted and addressed these risks in using more recent information.

## F.2.2 WSP’s approach

### F.2.2.1 Risk assessment

WSP utilised the standard risk assessment methodology captured in the following equation:

$$\text{Risk level} = \text{Probability of failure} \times \text{Consequence of failure}$$

We look at each component in turn.

#### The probability of failure

An AHI was used to represent this component of the risk equation. WSP assessed the quality of the available asset conditions and performance data for each fleet to determine the AHI of the respective fleet. It discovered the overall asset condition and performance data was generally of poor quality across all the fleets. WSP had to manipulate and extrapolate the available asset condition and performance data to infer knowledge and to draw conclusion on asset failure likelihood.

For most fleets, the AHI was proxied by remaining life of the assets in years. The remaining life of the asset is a simple deterministic calculation deducting the asset age from the expected life of the asset type. Low AHI (or low remaining life) denotes higher probability of failure. This calculation is premised on WSP’s expected life of the asset type and in many cases the best judgement of the asset age. This approach is not uncommon across the industry where asset condition data for low value high volume fleets are not readily available.

In several cases the AHI could be determined:

- *Quantitatively* based on the range of available asset fleet condition and performance data (e.g. wood poles and zone substation power transformers), or
- *Qualitatively* based on engineering judgement of historical test records and asset performance data (e.g. protection system).

Importantly, the AHI category definitions were applied differently by WSP when undertaking its assessment than how they have been applied by Aurora Energy in its CPP proposal – as shown in Figure F.1. This means that the number of assets falling within each category will not be the same.

The most critical categories adopted by each – H5 in WSP’s assessment and H1 in Aurora Energy’s assessment – are the same in that the probability of failure is ‘almost certain’.<sup>306</sup> WSP used the AHI to provide a qualitative risk matrix approach to assessing risk. Aurora Energy’s models are now more advanced – generally incorporating probability of failure and condition data in its models to forecast replacement volumes. AHI is an *output* of each of Aurora Energy’s models not an *input*.

The AHI categories used by WSP and Aurora Energy are both not strictly the same as the definition in the EEA Guide.

Figure F.1: Comparison of AHI definitions – WSP vs Aurora Energy

WSP categories				Aurora Energy categories		
RANKING	DESCRIPTION	QUALITATIVE	ASSET HEALTH INDEX	AH SCORE	CATEGORY DESCRIPTION	REPLACEMENT PERIOD
5	Almost certain	Happened in last year in location	>100% nominal life	H1	Asset has reached the end of its useful life.	Within one year
4	Likely	Happened in last year in company	90% to 100% nominal life	H2	Material failure risk, short-term replacement	Between 1 and 3 years
3	Possible	Happened in last year in industry	80% to 90% nominal life	H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
2	Unlikely	Heard of in industry	50% to 80% nominal life	H4	Normal deterioration, monitor regularly	Between 10 and 20 years
1	Rare	Unheard of in industry	0% to 50% nominal life	H5	As new condition, insignificant failure risk	Over 20 years

### The consequence of failure

WSP considered three consequences of asset failure – safety, reliability (based on value of lost load), and environment. This was segmented by:

- Population density and impact outcome (for safety consequences)
- Economic outcome (for reliability), and
- Location and penalty exposure (for environment consequences).

The highest possible consequence, or criticality, was assigned given the various asset failure modes. Safety and reliability consequences were analysed using basic quantitative approaches and the environmental consequences were analysed using a qualitative approach.

WSP assessed the quality of the available asset attribute and performance data for each fleet to determine the consequence parameters of the respective fleet. It discovered that the overall asset attribute and performance data generally across all the fleets were of medium quality. WSP had to somewhat extrapolate the available asset attribute and performance data to infer knowledge and to draw conclusions on asset criticality.

### Risk level

For a given asset, WSP considered simultaneously both the probability of asset failure and consequence of asset failure to determine the risk level of that asset. This was determined for each risk level segment within each asset fleet. At a fleet level, it determined asset volumes at various risk levels.

WSP modelled the asset risk using a qualitative approach based on Aurora Energy’s risk management framework and using the 5×5 risk matrix to present the findings. This is not directly comparable to

<sup>306</sup> WSP, *Independent review of electricity networks*, final report, November 2018, p. 16; and Aurora Energy, *2019 Asset Management Plan Update*, 2019, p. 97.

Aurora Energy's approach and purpose – which was aimed at more accurately and quantitatively determining replacement volumes and treating risk assessment in different ways depending on the type of renewal model..

Considerable work was undertaken by WSP to assume, clean, corroborate, infer, extrapolate and manipulate the asset data – attribute, performance and condition – to address the data quality and data gap issues to determine the risk levels as per this methodology in every asset fleet. This needs to be appreciated when referring to WSP report, which categorises specific volumes of asset into different risk levels for every asset fleet. This resulted in tailored analysis for every asset fleet.

### F.2.2.2 Forecast to reduce risk level

The risk assessment was performed by WSP in a tailored manner as described in section F.2.2.1 identifying a total volume of assets for each fleet that were judged to be posing an intolerable risk – generally based on volumes deemed to fall within high and very high segments of the risk matrix, with some falling within the medium segment.

The risk category affected the potential interventions identified to mitigate the risks and – in most cases – when assets were projected to be replaced. This relationship is illustrated by the following equation:

$$\textit{Forecast volume} = \textit{Assets with intolerable risk levels}$$

## F.2.3 Aurora Energy's approach

### F.2.3.1 Risk assessment

Aurora Energy's approach to assessing risk differs from WSP's and appears more accurate when forecasting required asset renewals (including as to timing) – with inherent residual risks incorporated into most of the forecast models. Inherent risk is assumed to match the tolerable risk and was determined using industry experience and historical data, including WSP's findings.

Explicit risk assessments were not developed by Aurora Energy, except for the zone substation renewal models. Aurora Energy's approach is consistent with the approach undertaken by WSP – in that the similar sets or subsets of asset data (condition, performance and attributes) inputs are being used to inform the forecast.

There *are* differences across the asset fleets in the manner of how the asset data is used to generate the forecast. These differences are due to:

- limitations with the asset management system and the underlying data – which Aurora Energy has come to appreciate since 2018, and
- developing models fit for purpose not unlike other industry peers.

On the latter, Aurora Energy has used the following different modelling methods (refer section 4.6.1) to forecast replacement volumes and expenditure:

- **probabilistic models** – e.g. poles
- **condition and consequence-based risk models** – e.g. zone substation programs for power transformers and indoor switchgear
- **age based models** – e.g. crossarms, conductors, LV enclosures, and outdoor circuit breakers.

How the probability and consequence of failure have been inherently incorporated in these models is described in Table F.1 below and compared to the WSP approach. In summary, the table shows that WSP

effectively used a *more qualitative* approach to assess risks within the different fleets whereas Aurora Energy needed to develop models that are aimed at more accurately and quantitatively determining replacement volumes. These differences are reasonable in the circumstances.

Table F.1: Aurora Energy risk assessment approach details

Model Method	Probabilistic model	Condition and consequence-based risk models	Age-based models
Probability of failure (likelihood/Pof)	<p><b>Poles</b> – the available historical failure rate data has enabled Aurora Energy to build an asset specific survival curve for poles. The Pof is then quantitatively based on historical data.<sup>307</sup> The AHI is an output of the model and is not used as part of the model.</p> <p>The assumption used in this model is that future failure rates will equal historical failure rates.</p> <p>The model is further advanced than WSP was able to apply at the time of its assessment.</p>	<p><b>Zone substation programs</b> – the AHI is determined quantitatively based on range of available asset data (e.g. DGA test result, visual inspection, furan analysis, remaining age etc. for the zone substation power transformers). The AHI is a proxy for the Pof and used as part of the model.</p> <p>The accuracy of the AHI depends on the mapping of condition to overall asset health.</p> <p>The model is further advanced than WSP was able to apply at the time of its assessment.</p>	<p><b>Other programs</b> – this deterministic approach assumes that the expected life of the asset is the average Pof of the asset. The AHI is an output of the model and is not used as part of the model.</p> <p>The assumption used in this model is that the estimate of the expected life represents the point at which the asset has reached an intolerable level of risk of actual failure (on average).</p> <p>The model is like that used in the WSP Report.</p>
Consequence of failure (criticality or impact)	<p><b>Poles</b> – Aurora Energy has not considered criticality directly in the pole model to forecast replacement volumes as the value of this is relevant only to the urgency of replacement and inspection strategy. The criticality considers only the safety consequence.</p> <p>Aurora Energy plans to refine a differentiated approach to priority during the CPP period based on safety risk as the prime driver and to meet response compliance to</p>	<p><b>Zone substation programs</b> – Aurora Energy has considered the same three dimensions of consequence – safety, reliability (based on value of lost load), and environment as used by WSP.</p> <p>Aurora Energy used a similar methodology to measure and analyse these consequence dimensions as WSP and to use criticality in risk assessment approaches within these models.</p>	<p><b>Other programs</b> – Aurora Energy has not considered criticality directly in other models to forecast replacement volumes as the value of this is relevant only to the urgency of replacement and inspection strategy. The criticality considers only the safety consequence.</p> <p>Aurora Energy plans to refine a differentiated approach to priority during the CPP period based on safety risk as the</p>

<sup>307</sup> Pof in this case means that the assessed asset (e.g. remaining pole strength is not sufficient) has reached an intolerable level of risk of actual failure

Model Method	Probabilistic model	Condition and consequence-based risk models	Age-based models
	the orange and red tagging of poles.		prime driver for overhead line assets.
Risk assessment approach and application	<p><b>Poles</b> – the Aurora Energy model assumes that the survival curve – based on historical replacement behaviour – includes the margin of safety that aligns with a tolerable level of risk of actual failure (i.e. ALARP).</p> <p>The AHI is used to represent this inherent risk assessment with or without replacements.</p> <p>WSP illustrated risk via a corporate risk matrix and this was relevant to the purpose of its assessment. This approach is high level and insufficient to more accurately forecast replacement volumes, but can be used for prioritising replacements.</p>	<p><b>Zone substation program</b> – tailored analysis has been used for this low volume high value asset fleet.</p> <p>This approach by Aurora Energy is similar to the WSP approach, except that the model uses more advanced analysis suitable for forecasting replacement volumes.</p> <p>The risk assessment considers both the probability of asset failure and consequence of asset failure to identify overall risk of failure (i.e. ALARP).</p> <p>At fleet level, this approach determines what specific assets should be prioritised based on risk to reliability, safety and the environment.</p>	<p><b>Other programs</b> – the Aurora Energy models assumes the expected life – with a probability distribution – includes the margin of safety that aligns with a tolerable level of risk of actual failure (i.e. ALARP).</p> <p>The AHI is used to represent this inherent risk assessment with or without replacements.</p> <p>As with the probabilistic model, WSP illustrated risk via a corporate risk matrix and this was relevant to the purpose of its assessment. This approach is high level and insufficient to more accurately forecast replacement volumes but can be used for prioritising replacements.</p>

### F.2.3.2 Forecasts to reduce risk level

Following on from how risk assessment has been treated as explained in section F.2.3.1, the forecasting approach adopted by Aurora Energy differs according to the modelling approach and the assessment of risks in those models.

Except for the condition and consequence-based risk modelling approach – i.e. for zone substation programs – the risk assessment method has not been explicitly expressed by Aurora Energy in their documentation. This does not mean that the approach used for determining inherent and residual risk levels by Aurora Energy is unsatisfactory where it has not been explicitly expressed in Aurora Energy documentation.

In such cases, we used benchmarking techniques to compare the output metrics – e.g. annual replacement rate, failure rate, risk or age profile etc. – with that of other EDBs to test whether the risk assessment and the resulting expenditure forecast was reasonable with respect to managing risks or not. Our benchmarking is further detailed in Appendix D.

Table F.2: Aurora Energy forecasting approach

Model Method	Probabilistic model	Condition and consequence-based risk models	Age-based models
Forecasting	<p><b>Poles</b> – at the fleet level, the renewal forecast volume is determined based on the available historical data on the distribution of pole replacements to age.</p> <p>This produces a survival curve which is then used to forecast volumes expected to need replacement in the future.</p> <p>The forecast using this approach assumes a continuation of the historical risk tolerance based on industry factors of safety.</p> <p><i>Forecast volume = Assets with intolerable risk levels (implicit)</i></p> <p><b>Note:</b> A high actual failure rate of poles in the past appears due to an inadequate inspection and test strategy and not the volume of poles needing to be replaced.</p>	<p><b>Zone substation program</b> – within the fleet, each plant asset is assessed based on risk reaching an unacceptable level.</p> <p><i>Forecast volume = Assets with intolerable risk levels (explicit)</i></p> <p>The forecast following this risk assessment approach aims to provide a refined and optimised forecast specific to Aurora Energy’s network and operating risks.</p>	<p><b>Other programs</b> – at the fleet level, the renewal forecast volume is determined by defining the expected life of asset types in the fleet. This is based on engineering judgement, general historical and industry experience, in the absence of available data to develop a more accurate probabilistic model.</p> <p>A survival curve can be approximated and then used to forecast volumes expected to need replacement in the future.</p> <p><i>Forecast volume = Assets with intolerable risk levels (implicit)</i></p> <p><b>Note:</b> Critical examination of the key input parameters (e.g. age profile and expected asset life) and benchmarking to other EDBs is warranted to test the implicit risk assessment in these models.</p>
Work or mitigation measure delivery	<p><b>Poles</b> – Aurora Energy plan to refine a differentiated approach to priority during the CPP period based on safety risk – public exposure – as the prime driver and to meet response compliance to the orange and red tagging of poles.</p>	<p><b>Zone substation program</b> – this program addresses the risk associated with specific assets in the fleet and therefore prioritisation and coordination within specific zone substation projects can be performed at this stage of planning.</p> <p>Risk has been used to prioritise the work program.</p>	<p><b>Other programs</b> – Aurora Energy plans to develop criticality models and use the consequence of asset failure to prioritise the delivery of renewal work following the identification of specific assets requiring replacement during the CPP period.</p> <p>Risk is planned to be used to prioritise the work program.</p>

#### F.2.4 Our view on network risks

Table F.3 presents the network risks identified by WSP in its 2018 report, how they have been addressed in Aurora Energy's AMP and respective asset strategies (i.e. PODs), and our opinion on adequacy and reasonableness of Aurora Energy's plan to mitigate those network risks.

The table uses the same structure of asset fleet categories as presented in WSP's report. The discussion is limited to the following asset fleets whose renewal forecast programs were identified for independent verification:

- protection system
- zone substation indoor circuit breakers
- zone substation outdoor circuit breakers
- zone substation power transformers
- zone substation buildings
- poles
- crossarms
- overhead distribution conductors
- overhead LV conductors
- LV enclosures.

Table F.3: Assessment of Aurora Energy’s strategies to address WSP identified network risks

Asset fleet	WSP identified risk	Aurora Energy’s strategy	Our opinion
<b>Protection systems</b>	<ul style="list-style-type: none"> <li>The key drivers for renewal are the technological obsolescence of the fleet and the safety consequence. For example, 382 electromechanical relays (36% of the relay fleet) and 106 electronic relays (10% of the relay fleet) are exceeding their expected life. Safety is a high risk due to failure to operate.</li> <li>384 relays identified with very high-risk level.</li> <li>179 relays identified with high risk level.</li> </ul>	<ul style="list-style-type: none"> <li>Preventive maintenance approach and proactive spares management.</li> <li>Aurora Energy has not prepared an AHI scoring for protection relays, instead qualitatively considering technology obsolescence and market support issues.</li> <li>Remove all electromechanical relays from service by RY24.</li> <li>Remove all static electronic relays by RY25.</li> <li>Target to replace all protection relays that have reached end-of-life by RY30 (i.e. remove the backlog of other types of relays requiring renewal).</li> <li>Priority replacement given to higher risk protection schemes.</li> <li>Renewals undertaken to match capability to deliver and ensure efficient deliverability.</li> <li>MOD24 suggests that after RY25 less than 2% of relays will be above their expected life with a steady replacement of schemes after RY25.</li> </ul>	<ul style="list-style-type: none"> <li>The strategy is reasonable given the existing AMS maturity and the deliverability constraints.</li> <li>The risks with this asset portfolio have already reached high risk level and replacements are to be scheduled over the CPP and review periods based on risk priority.</li> <li>Asset strategies and expected life of modern microprocessor relays should be reviewed as experience is gained with these relay types.</li> </ul>
<b>Zone substation indoor switchgear</b>	<ul style="list-style-type: none"> <li>The key drivers for renewals are age profile (especially oil CBs), worker safety risk (arc fault), and reliability consequence.</li> <li>Prevalence of outages caused by deterioration of oil type CBs.</li> </ul>	<ul style="list-style-type: none"> <li>Adequate regime of preventive maintenance based on maximum time period or maximum number of switching operation.</li> <li>Retains strategic spare components.</li> </ul>	<ul style="list-style-type: none"> <li>The risks with this asset portfolio appear to have been adequately addressed.</li> <li>Our independent verification of this proposed program is provided in greater detail in Appendix C and Appendix D.</li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
	<ul style="list-style-type: none"> <li>• 30 CBs (inclusive of outdoor types) identified with very high-risk level.</li> <li>• 75 CBs (inclusive of outdoor types) identified with high risk level.</li> </ul>	<ul style="list-style-type: none"> <li>• Both AHI and criticality are simultaneously considered to assess the risk levels. AHI score is based on remaining life. Criticality score is advance based on various metrics representing safety, resilience, security and reliability.</li> <li>• Focus on improving the capturing and analysis of asset performance data, which is presently limited.</li> <li>• Renewal forecast is coordinated with other zone substation asset portfolios for timing synergies.</li> <li>• The plan is to replace 6 switchboard panels. A change to the specific included panels has been made since we reviewed the initial program based on the risk assessment.</li> </ul>	<ul style="list-style-type: none"> <li>• Based on our draft verification, the renewal forecast for this fleet has been rationalised. The updated strategy is reasonable given deliverability constraints.</li> </ul>
<b>Zone substation outdoor switchgear</b>	<ul style="list-style-type: none"> <li>• The key drivers for renewal are age profile (especially oil CBs, few vacuum CBs and CBs housed in DIY cubicles), worker safety risk (arc fault), and reliability consequence.</li> <li>• Prevalence of outages cause by deterioration of oil type CBs.</li> <li>• 30 CBs (inclusive of indoor types) identified with very high-risk level.</li> <li>• 75 CBs (inclusive of indoor types) identified with high risk level.</li> </ul>	<ul style="list-style-type: none"> <li>• Adequate regime of preventive maintenance based on maximum time period or maximum number of switching operation.</li> <li>• Only AHI is considered to assess the risk levels. AHI score is based on remaining life.</li> <li>• Criticality scoring is not developed for this asset fleet, and instead refers to the consequence of the associated zone substation other assets.</li> <li>• Focus on improving the capturing and analysis of asset performance data, which is presently limited.</li> </ul>	<ul style="list-style-type: none"> <li>• The strategy is reasonable given deliverability constraints.</li> <li>• The risks with this asset portfolio appear to have been adequately addressed.</li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
		<ul style="list-style-type: none"> <li>• Renewal forecast is coordinated with other zone substation asset portfolios for timing synergies.</li> <li>• Plan to replace 35 switches and 26 CBs/reclosers during the review period.</li> </ul>	
<b>Zone substation power transformers</b>	<ul style="list-style-type: none"> <li>• The key driver for renewal is tap changer component conditions and reliability consequence.</li> <li>• 0 transformer identified with very high-risk level.</li> <li>• 8 transformers (12.7%) identified with high risk level.</li> </ul>	<ul style="list-style-type: none"> <li>• Adequate regime of routine inspections and preventive maintenance.</li> <li>• Retain strategic spare components.</li> <li>• Both AHI and criticality are simultaneously considered to assess the risk levels. AHI score is advanced based on asset age, diagnostic tests, inspection results of various components, and tap changer operation. Criticality score is advanced based on various metrics representing resilience, security and reliability.</li> <li>• Tap changer maintenance being brought up to date and replacement considered if the remaining parts of the transformer (i.e. tank/windings/etc.) are in good condition.</li> <li>• Renewal forecast is coordinated with other zone substation asset portfolios for timing synergies. For example, 19 transformers were flagged during the review period but only 11 are being programmed for replacement.</li> </ul>	<ul style="list-style-type: none"> <li>• The strategy is reasonable given deliverability constraints.</li> <li>• The risks with this asset portfolio have been adequately addressed.</li> <li>• Our independent verification of this proposed program is provided in greater detail in Appendix C and Appendix D – although, in our view, the renewal modelling gives a conservative forecast of required replacement, it is moderated in the coordination model.</li> <li>• The past poor maintenance practices on tap changers have prematurely defined end of life for several transformers.</li> </ul>
<b>Zone substation buildings</b>	<ul style="list-style-type: none"> <li>• This fleet was assessed for network resilience against high impact natural disasters.</li> </ul>	<ul style="list-style-type: none"> <li>• Fleet strategy is based on assessment against and recommendation from NZSEE Seismic Grade and New Building Standard.</li> </ul>	<ul style="list-style-type: none"> <li>• The strategy is reasonable given the existing AMS maturity and the deliverability constraints.</li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
	<ul style="list-style-type: none"> <li>Zone substation buildings were not specifically assessed for network risks and recommended for mitigation measure in the WSP report.</li> <li>The limited discussion of this fleet was in association with power transformers. Based on its site visits, WSP noted on asset attribute data management, safety standards, security, bunding, and proximity issues.</li> </ul>	<p>Therefore, risk assessment follows a tailored approach and recommended projects are for site specific works.</p> <ul style="list-style-type: none"> <li>Renewal forecast includes replacement, reinforcement, decommissioning and relocation of civil infrastructure.</li> <li>New buildings will be designed to IL4 standard and the existing buildings will be reinforced to IL3 standard.</li> <li>Plans to replace buildings are three sites and build new at two sites (to house switchgear indoor) during the review period.</li> <li>A one-off structural assessment of all zone substation buildings has been undertaken with an associated remediation plan underway.</li> <li>Building inspection regime is limited to fire system testing and detecting airborne asbestos.</li> </ul>	<ul style="list-style-type: none"> <li>The risks with this asset portfolio appear to have been adequately addressed.</li> <li>Building inspection should also include civil and structural engineering checks.</li> </ul>
<b>Poles</b>	<ul style="list-style-type: none"> <li>Key drivers for renewal are condition (hardwood poles) and public safety risk.<sup>308</sup></li> <li>Simplistic remaining age-based analysis indicated an upper limit forecast of 6,660 poles requiring renewal. However, modelling with a survivor curve indicated a much lower</li> </ul>	<ul style="list-style-type: none"> <li>Undertaking the FTPP and addressing a renewal backlog has arrested the heightened safety risk due to historical neglect.</li> <li>The pole inspection strategy has been revised, including the Deuar MPT method.</li> </ul>	<ul style="list-style-type: none"> <li>The risks with this asset portfolio have been adequately addressed.</li> <li>The strategy during the CPP period is reasonable apart from consideration of an ongoing pole reinforcement program.</li> </ul>

<sup>308</sup> Asset age-based end of life analysis was undertaken using a survivor curve distribution using historical asset replacement and failure data for wood poles. Concrete and steel pole are relatively young and healthy.

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
	<p>volume (1,630), which aligns with past experience.</p> <ul style="list-style-type: none"> <li>• Pole inspection program was not mature enough to assess condition data.</li> <li>• Zero poles were identified to provide a very high-risk level.</li> <li>• 1,397 poles were identified with a high-risk level.</li> </ul>	<ul style="list-style-type: none"> <li>• Risk is addressed via the inspection frequency and accuracy of the test method to determine remaining pole strength.</li> <li>• A criticality model is planned to be developed to prioritise work delivery.</li> <li>• A focus will be on improving pole testing and data capture over the CPP and review periods.</li> <li>• A wood pole reinforcement strategy has not been incorporated into the forecasts.</li> <li>• The plan is to replace 800 poles per annum in the review period.</li> </ul>	<ul style="list-style-type: none"> <li>• Wood pole reinforcement should be reviewed within the CPP period to confirm the viability or otherwise of continuing with a reinforcement program at least from RY25 onwards.</li> <li>• Our independent verification of this program is provided in greater detail in Appendix C and Appendix D with regard to this matter.</li> </ul>
<b>Crossarms</b>	<ul style="list-style-type: none"> <li>• Key driver for renewal is the age profile (hardwood crossarms) and public safety risk.</li> <li>• Simplistic remaining age-based analysis indicated an upper limit forecast of 44,262 crossarms requiring renewal. This is based on an approximated age profile.</li> <li>• Poletops and crossarms have not been inspected in the past to collate accurate and complete condition data.</li> <li>• Zero crossarms were identified to have a very high-risk level.</li> <li>• 2,142 crossarms were identified with a high-risk level. Additionally, ~3,600 Malaysian hardwood crossarms were identified with a high-risk level due to fungal growth.</li> </ul>	<ul style="list-style-type: none"> <li>• No historical dedicated crossarms renewal program in the past. Crossarms were opportunistically replaced during pole and conductor replacement programs or upon failure.</li> <li>• A focus is on capturing and analysing asset condition data. Plans are to incorporate visual inspection (from above) in the inspection regime from RY21.</li> <li>• The risk is inherently based on the calculation of the remaining life to expected life. The expected life is based on an assumed balance between replacement volumes and the risk of unassisted failures.</li> <li>• Criticality score considers only safety dimension and will be used after</li> </ul>	<ul style="list-style-type: none"> <li>• The strategy is reasonable given the existing AMS maturity, deliverability constraints, and available data.</li> <li>• The risks with this asset portfolio appear to have been adequately addressed based on an expected life that is consistent with that for other EDBs and hence the inherent risk addressed by other comparable entities.</li> <li>• The replacement of 5,000 crossarms per annum compares reasonably with WSP upper limit of 44,262, which would equate to a replacement of 8,852 per annum over a five-year period.</li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
		<p>establishing the forecast to prioritise work delivery.</p> <ul style="list-style-type: none"> <li>Focus on improving the capturing and analysis of asset failure data related to supply reliability, which is presently limited/incorrect.</li> <li>The plan to replace 3,000 crossarms per annum in the review period under this program. Additionally, a further ~2,000 crossarms per annum will be replaced and included within the poles and conductor renewal programs.</li> </ul>	
<p><b>Overhead distribution conductors (6.6 kV, 11 kV)</b></p>	<ul style="list-style-type: none"> <li>Asset condition data for this fleet is unavailable.</li> <li>Asset performance data for this fleet is very limited and has gaps and quality issues.</li> <li>There are 162 km of ACSR conductors and 35 km of steel conductor currently exceeding their expected life. The failure rate of these ACSR and steel conductors was considered high resulting in outages. Recent public safety incidents can be related to the failure of conductors.</li> <li>The key drivers for renewals are the assumed asset condition (using statistical analysis) and safety and reliability consequences.</li> <li>Zero km of conductor was identified with a very high risk of level.</li> </ul>	<ul style="list-style-type: none"> <li>The plan is to increase forensic testing of failed and replaced conductors to better understand the condition of the assets.</li> <li>Improve data collection to better classify conductor failure causes.</li> <li>Cyclic routine inspection to identify defects (broken strands, clashing, bulges and tree impacts).</li> <li>The expected life is based on an assumed balance between replacement volumes and the risk of unassisted failures.</li> <li>Criticality score considers only safety dimension and will be used after establishing the forecast to prioritise work delivery.</li> <li>Targeted risk assessment and renewal program for specific under clearance spans,</li> </ul>	<ul style="list-style-type: none"> <li>The strategy is reasonable given the existing AMS maturity and the deliverability constraints.</li> <li>The balance of risk, costs and deliverability with this asset portfolio appears to have been adequately addressed.</li> <li>The replacement of 30 km per annum of conductor reasonably compares and lies between: <ul style="list-style-type: none"> <li>the WSP assessment of asset quantity that exceeded the expected life, and</li> <li>the identified asset quantities with intolerable risks over a five-year period.</li> </ul> </li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
	<ul style="list-style-type: none"> <li>9 km of conductor (including overhead LV conductors) was identified at a high-risk level.</li> <li>225 spans identified with non-compliant to minimum height.</li> </ul>	<p>in addition to the volumetric conductor assessment.</p> <ul style="list-style-type: none"> <li>Replace 30 km of conductor per annum and the identified 225 under clearance spans in the review period.</li> </ul>	
<b>Overhead LV conductors (230V, 400V)</b>	<ul style="list-style-type: none"> <li>Asset condition data for this fleet is unavailable.</li> <li>Asset performance data for this fleet is unavailable.</li> <li>There are 309 km of copper conductor currently exceeding their expected life. The failure rate of this copper conductor is high. Recent public safety incidents can be related to the failure of this asset.</li> <li>Key drivers for renewal are assumed asset condition (using Weibull modelling analysis) and safety and reliability consequences.</li> <li>Zero km of conductor identified with a very high-risk level.</li> <li>9 km conductor (including overhead distribution conductors) identified with a high-risk level.</li> </ul>	<ul style="list-style-type: none"> <li>The plan is to record LV conductor failure incidents in the future. Plan to increase forensic testing of LV conductor and target the testing program to better understand the asset condition and performance information.</li> <li>Cyclic routine inspection incorporated in the pole inspection regime to identify superficial defects (broken strands, clashing, bulges and tree impacts).</li> <li>The expected life is based on an assumed balance between replacement volumes and the risk of unassisted failures.</li> <li>Criticality score considers only the safety dimension and is used after establishing the forecast to prioritise work delivery.</li> <li>Conductor renewal program also includes opportunistic replacement of some of the associated crossarms and poles of the same feeder.</li> <li>Plan to replace 31 km of conductor per annum in the review period.</li> <li>Plan to follow the learnings from the HV conductor replacement program.</li> </ul>	<ul style="list-style-type: none"> <li>The strategy is reasonable given the existing AMS maturity and the deliverability constraints (including internal resourcing).</li> <li>The risks with this asset portfolio appear to have been adequately addressed.</li> <li>The replacement of 31 km per annum of conductor reasonably compares and lies between: <ul style="list-style-type: none"> <li>the WSP assessment of asset quantity that exceeded the expected life, and</li> <li>the identified asset quantities with intolerable risks over a five-year period.</li> </ul> </li> </ul>

Asset fleet	WSP identified risk	Aurora Energy's strategy	Our opinion
<b>LV Enclosures</b>	<ul style="list-style-type: none"> <li>No historical inspection data available previously, hence no asset condition data. Also, asset attribute (age) data has significant unknown data gaps.</li> <li>No historical performance data was available for this fleet because LV outage data is not recorded.</li> <li>The LV enclosures were not specifically assessed for network risk and recommended for mitigation measures as a separate asset fleet in the WSP report.</li> <li>The assessment of this asset fleet was limited to analysing historical safety incidents. The report noted there were 147 LV enclosure defects recorded during 2015 to 2018, which presented potential hazards. No serious hazard (heightened risk to public or workers due to live assets within it being exposed) was recorded during this time period.</li> <li>Key consequences due to asset defects or failure were identified as safety risks to the public and workers if the asset within it were exposed.</li> </ul>	<ul style="list-style-type: none"> <li>The plan has been to start five yearly visual inspections and testing earthing integrity.</li> <li>Third party (vehicle and vandalism) damage is a significant cause for asset defects and failures and addressed through corrective action.</li> <li>Replace all of Henley in-ground LV enclosure due to water ingress and arc flash potential issues.</li> <li>The expected life was based on a nominal figure with data to support the assumption</li> <li>The balance between replacement volumes and the risk of shocks to the public was also assumed with no separate assessment.</li> <li>Public safety risk will be used to prioritise work delivery after defects are identified.</li> <li>Renewal forecast is driven by the volume of assets exceeding the assumed life.</li> <li>Initial plans were to replace ~400 LV enclosure per annum have now been reduced to 242 LV enclosures per annum over the review period.</li> </ul>	<ul style="list-style-type: none"> <li>The risks with this asset portfolio appear to have been adequately addressed.</li> <li>Our independent verification of this proposed program is provided in greater details in Appendix C and Appendix D.</li> <li>Based on our draft verification, the renewal forecast for this asset fleet has been moderated. The updated strategy is reasonable given the existing AMS maturity and the deliverability constraints.</li> </ul>

## F.2.5 Network maintenance

Utilities with high asset management maturity typically have five approaches to maintenance:

- **age-based**
- **time-based**
- **condition-based** – maintenance done when considered the most effective action
- **risk-based** – considering condition of asset and consequences and associated risks of failure
- **reliability** – centred considering maintaining system reliability and performance.

For such utilities, maintenance intervals that describe the frequency of maintenance activities are informed by key inputs such as asset performance, asset environment, asset criticality, asset health modelling and regular asset condition monitoring practices. These intervals will generally be regularly challenged to ensure that maintenance on assets is optimised as best as possible. This is consistent with GEIP.

Aurora Energy has been assessed as currently having a low level of asset maturity.<sup>309</sup> As Aurora Energy develops and improves its asset management systems and practices, we would expect that maintenance intervals will be reviewed and set to best suit the needs of the asset populations to minimise life-cycle costs and achieve maximum in-service life.

Table F.4 compares Aurora Energy's nominated intervals for preventive/routine maintenance of the asset fleets (as described in its 2019 AMP and as clarified subsequently by Aurora Energy)<sup>310</sup> with a selection of NZ EDB peers and with our experience of intervals/cycles in the Australian electricity industry. In our view, Aurora Energy has generally nominated inspection, testing and maintenance cycles that are comparable to peers in NZ and Australia, and therefore implicitly manage the maintenance of its assets at similar risk levels to its peers.

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<sup>309</sup> Covaris, Aurora Energy - Asset Management Maturity Assessment, version 1-1, November 2017

<sup>310</sup> Aurora Energy advised that some of the intervals contained in the 2019 AMP were no longer appropriate and so we have updated them in the table to reflect what we understand Aurora Energy will include in its 2020 AMP.

Table F.4: Comparison of Aurora Energy nominated maintenance cycles

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
<b>Feeders</b>				
Support structures (poles)	Ground-based inspection/condition assessment (Deuar MPT)	5 years (priority set by public safety criticality)	5 years	4-5 years
	Drive-by inspection	Partial annual coverage with other programs and high public safety critical poles yet to be inspected during cycle	Annual	-
Cross-arms	Visual inspection	Partial annual coverage as part of conductor inspection and ad hoc defect reporting	Annual	Annual
	Detailed visual inspection	5 years (as part of pole inspection)	5 years	4-5 years as part of pole inspection

<sup>311</sup> Based on intervals nominated in current AMPs for Powerco, Unison, Orion and The Power Company as a sample selection.

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
Overhead conductor	Condition check (visual inspection)	Annual ground and/or air inspections on subtransmission conductor to identify and prioritise defects and vegetation infringements, and collect condition data	Annual Orion retightens components initially 12-18 months then at 30 year intervals	Annual
	Detailed condition assessment	5-yearly detailed condition assessment of all OH (subtrans, distribution, LV {yet to be stated}) to assess condition of conductor, in conjunction with pole condition assessments	5 years Orion conducts 2-yearly thermal imaging and UV corona inspection	4-5 years as part of pole inspection
Underground cables	Oil and gas-filled pressure tests on subtransmission cables	2 weeks	1-2 months	2-4 weeks
	Alarm tests on subtransmission cables	6 months	6 months	6 months
	Ground-based inspection	Annual	Annual Unison includes thermal imaging	Annual Some utilities conduct 2 yearly thermal imaging or as needed

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Outer sheath integrity test	Annual	Powerco: 2-5 years Unison: 3-5 years TPC Annual Orion: HV cables: 1-4 years; MV cables: 5 years	HV cables: 2 years MV cables: 4 years
<b>Distribution switchgear</b>				
Ground-mounted switchgear	Routine inspection	Annual proposed to be implemented	Annual Orion: 6 months	Annual
	Major test/overhaul	6 years	5-10 years	8-10 years
Pole-mounted switchgear	Visual inspection/operational check	5 years proposed to be implemented	5 years Unison visually inspects all transformers twice in 5 years on 5 visual/5 earthing inspect & test cycles	4 years
Reclosers & sectionalisers	Thermal imaging	Annual	1 - 2.5 years	2 years

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Major test/overhaul	4 years	5-10 years	8-10 years
	Functional testing	4 years, in conjunction with protection testing	5 years Unison tests recloser 2 years	4 years
<b>Distribution transformers</b>				
Ground-mounted transformers	Visual inspection	Annual with load monitoring	6 months	3-4 months
	Condition assessment	3 years	5 years	3 years
	DGA testing	Not currently undertaken	TPC tests critical units at end-of-life	2 years
	Load monitoring	Annual proposed	6 months -1 year	Annual
Pole-mounted transformers	Visual inspection	5 years, in conjunction with pole inspection	5 years	Annual
LV enclosures	Inspection/minor repairs	5 years	5 years	4 years
	Earthing integrity	5 years	-	8 years
Voltage regulators	Visual inspection	Annual	6 months	Annual
	Thermal imaging	Annual	2.5 years	-

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Major overhaul	4-10 years (or 100,000 to 120,000 operations)	5 years	4 years
Mobile substation	Visual inspection	6 months	Annual	-
	Return from service inspection	Upon return from field	-	-
Mobile generator	Inspection/operational check	1 month	-	3 months for operational checks; annual inspection
<b>Zone substations</b>				
Power transformers	Oil level readings	Monthly	Unison: Online	4 months
	Ground-level inspection	1 month	Powerco: 3 months Unison: annual thermal imaging TPC: 1 month Orion: 2 months	6 months
	Oil & DGA testing	Annual	Powerco: 3 years Unison: annual TPC: 2 years Orion: annual test, 2 years diagnostics	6 months - 2 years

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Bushing DLA testing	-	-	4 years
	Major maintenance	4 years	4-8 years	6-7 years
	Mid-life refurbishment	-	Half-life	25 years
	Tap changer refurbishment	3 years – varies by type	Unison: 2-10 years TPC: operation count Orion: 4-8 years	3-4 years
	Painting	10 years (as required, not routine)	-	-
Circuit breakers	Visual inspection	1 month	Powerco: 3 months Unison: 2 weeks urban, 1 month rural TPC: 1 month Orion: 2-6 months	1-3 months
	Thermal imaging	Annual	1-2 years	2 years
	Partial discharge test	Half-life (20 years) then 5 years	5-6 years	-

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Major maintenance	4 years	Powerco: 3 years' service Orion: 4-8 years	8-10 years
	Operational service	3 trips	Powerco: annual Unison: 2-4 years or after no. of fault operations Orion: 4-8 years	4 years
Air break switches	Visual inspection	4 years	6 years	4 years
Ancillary equipment	Inspection/service	1-2 years	Annual	Annual
Earth grid	Inspection/test	5 years	5 years	3 years for inspection 10 years for test
Mobile substation	Visual inspection	6 months	Annual	-
	Return from service inspection	Upon return from field	-	-
Buildings, grounds & fencing	Substation grounds maintenance	2 weeks	1-3 months Orion: 3 weeks	1 month

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	Condition assessment	-	1-2 years Powerco includes thermal imaging	Annual for 1/3 of assets 3 years all assets
	Fire protection inspection	Annual	-	2 years 4 years for smoke detector recalibration
<b>Secondary systems</b>				
DC systems	Battery checks	Visual – monthly Charter tests – annual	3 months	3 months
Protection systems	Routine testing	4 years in conjunction with primary equipment 2 years for electromechanical relays	Powerco: 3 years TPC: 5 years Orion ZS: 2 month inspection and 4 year test, Dist Sub 6 month inspection and 8 years test	2 years
	Inter-trip testing	6 months	-	6 months

Asset category	Activity	Aurora Energy interval	NZ EDB intervals <sup>311</sup>	GHD experience of industry intervals
	EM relay calibration	4 years in conjunction with ZS inspection (recently introduced 2 years as an additional risk control measure)	Powerco: 3 years electro-mech, 6 years electronic	6 years

### F.2.5.1 Implementation

Aurora Energy acknowledged that historical data is poor – with no formal record keeping – and any records that were kept are all paper-based or scanned data.

Although the nominated inspection, testing and maintenance intervals nominated by Aurora Energy are reasonable compared with GEIP, the WSP review identified several key deficiencies in the historical implementation of its maintenance strategy. This was identified as needing addressing to improve the asset condition dataset.

For the CPP and review periods, Aurora Energy has proposed several step changes in network maintenance opex (refer Appendix C) to address historical shortfalls in maintenance of some asset types, together with enhancing the inspection program to improve the overall data integrity and asset condition assessments.

This is consistent with WSP's findings – where it noted key examples of insufficient network maintenance in the past, including:<sup>312</sup>

- **Protection system assets** – many of these assets are operating beyond their nominal life, are based on obsolete technology and have been inadequately maintained. Aurora Energy currently has electromechanical relays that are consistently losing calibration between maintenance cycles. Failure of these protection relays can result in live conductors that have fallen to ground not being detected and de-energised. WSP noted that there were several instances where older electromechanical relays have failed to isolate an earth fault. WSP highlighted that protection assets pose a significant safety risk and should be prioritised.
- **Zone substation circuit breakers** – where the inspection, testing and maintenance of these assets appeared incomplete.<sup>313</sup> Some of the older oil-insulated units represent a higher risk to the network through poor reliability and field crew safety in the event of an uncontained arc fault. WSP noted that many of the specific types of circuit breaker in-service in the Aurora Energy network have been identified as having a higher risk of failure.
- **Zone substation transformers** – where transformer tap changers were showing signs of deterioration and some are behind their maintenance schedule.
- **Support structures** – where, although the pole inspection program had recently been improved, it had not identified all poles that were in poor condition as it has not yet covered the whole network and crossarms were not being inspected adequately, with many found to be in poor condition. Some poles were categorised as a high risk due to their location.
- **Distribution switchgear** – where maintenance had not been undertaken consistently and there was no regular inspection program in place.<sup>314</sup> In addition, some of the switchgear in-service have oil leaks and may not operate correctly when required.

To address these concerns raised by WSP and other concerns it has identified, Aurora Energy has proposed an enhanced network maintenance program for the CPP and review periods – which led it to propose step changes for the following specific activities:

- **Increased electromechanical relay maintenance** – increased routine testing and calibration checks, and increased allowance for asset renewal capex and priority replacement strategy (refer Table F.3).

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<sup>312</sup> WSP, *Design for a better future: Aurora Energy - Independent Review of electricity networks*, Final report, 21 Nov 2018

<sup>313</sup> *Ibid.*, Executive Summary, p. xi.

<sup>314</sup> *Ibid.*, section 9.2.3, p. 78.

- **Zone substation circuit breakers** – enhanced asset renewal capex program to replace the older assets with known higher risks (refer Appendix C) and enhanced corrective maintenance following a fault operation.
- **Zone substation transformers** – increased asset renewal capex (refer Table F.3) and additional corrective maintenance included.
- **Pole top/crossarm inspections** – current ground-based inspection technique to be enhanced with cameras mounted on a ‘hot stick’ to inspect crossarms from the top.
- **LIDAR survey to provide quality data for vegetation management** – improve data relating to vegetation and line clearances.
- **Restart of ABS maintenance** – historically, Aurora Energy did not routinely maintain air break switches, resulting in assets that could not be operated when required. This initiative will restart 4-yearly visual inspections and servicing.
- **Support consumer owned pole strategy** – additional inspections as part of preventive maintenance, and corrective maintenance to ensure these poles are in a “reasonable standard of maintenance or repair” prior to being formally handed over to consumers. Timing for this initiative is being driven by a higher than average unassisted failure rate of consumer poles compared with the rest of the Aurora Energy pole population.
- **Inspections of distribution conductor condition, fittings and joints** – enhanced inspection program of distribution conductor, in response to increasing number of failures.
- **Helicopter inspections of subtransmission lines** – due to the criticality of the subtransmission overhead, a 5-yearly inspection program of the subtransmission lines will be conducted from a helicopter to improve condition assessment data.
- **LV enclosure inspections** - there is no historical inspection data available hence previously no asset condition data. Also, asset attribute (age) data with significant unknown data gaps. To address the risks these assets pose, particularly to the public and field crews, Aurora Energy is establishing a 5-yearly inspection program to identify any defects for rectification.
- **Surge arrester inspections** - to mitigate the risks posed by uncontained explosion hazard in public areas.
- **Pole-mounted asset inspections** - introducing routine inspection of pole-mounted transformers in conjunction with pole inspections.

We have reviewed the proposed expenditure associated with these step changes in Appendix C.

#### F.2.5.2 Prioritisation of maintenance

In Table F.4, we reviewed the nominated maintenance intervals for preventive activities, and concluded that the proposed intervals/cycles from Aurora Energy are reasonable in comparison with GEIP, and a sound basis for the programming preventive maintenance work.

In our review of corrective maintenance (refer Appendix C), we observe that – with the exception of poles, crossarms and poletops – Aurora Energy advised that at present there is no formal backlog of defects maintained, and defects are not graded.

During RY19, Aurora Energy graded pole defects using three levels:

- **Red** – poles at risk of failure under normal structural load; to be rectified within 3 months
- **Orange** – poles incapable of supporting design load; to be rectified within 12 months

- **Blue** – for poles with non-structural defects requiring repair or component replacement (crossarm/poletop) ; to be rectified within 24 months - this category of defect may be discontinued in the future.

Crossarms and poletops are also graded with crossarm defects classified D1 to D3 with short/medium/long term rectification based on the defect, and poletops graded as D4 or D5 depending upon whether the deterioration is significant or not.

For all other assets, in general terms, defects were prioritised by safety risks and a reduction in defect volumes was considered as addressing unacceptable safety and reliability positions. The stated intention of RCI maintenance in the Aurora Energy AMP is addressing defects timely and systematically before they give rise to failure.

It is accepted as GEIP that defects *should* be classified so as to assign a criticality and timeline for rectification to ensure defects are rectified in an efficient and optimal way. Aurora Energy has flagged that a defect grading system will be introduced following the introduction and implementation of an asset management system, recognising that it is a necessary initiative in ensuring efficient and effective corrective maintenance.

For the CPP period, Aurora Energy has forecast a nominal 10% increase in the number of defects identified due to the enhanced inspection regime that will be in place. During this time, we expect Aurora Energy will gain a better understanding of the nature of defects being identified. Through its field service providers it should also gain a better appreciation of how these defects should be prioritised. However, for the CPP period, we do not consider that the rectification of defects will be prioritised in line with GEIP.

Aurora Energy should examine defect grading as an important initiative to have in place ahead of RY25 to support more efficient expenditure in the next CPP period.

### F.2.5.3 Risk framework

Aurora Energy's primary driver its proactive maintenance and vegetation management is to reduce public safety risk and vegetation related outages on the network.

Poles, for instance, are currently assessed for structural strength as determined through the Deuar mechanical testing system and graded for any structural deficiency found, with poles tagged for rectification within a timeframe determined by the defect. Crossarms and poletops are currently graded for levels of deterioration and public safety risk through ground-level inspections. For all other assets, in general terms, defects are prioritised by safety risks and a reduction in defect volumes was considered as addressing unacceptable safety and reliability positions. Aurora Energy's AMP notes that RCI maintenance is intended to address defects timely and systematically before they give rise to failure.

Aurora Energy currently categorises vegetation affecting the distribution network as a 'very high risk' according to its corporate risk framework – and so started implementing a new vegetation management standard that requires a five-year cutting cycle. Two drivers for the vegetation program are:

- providing a safe network for the public, its staff and contractors
- reducing the risk of vegetation related events damaging network equipment.

Applying a risk framework should let Aurora Energy assess the need for defect rectification and vegetation cutting on a case by case basis through a more detailed evaluation of the risks posed by the defects or encroaching vegetation – allowing it to optimise the programming of work. For instance:

- Aurora Energy’s current defect rectification is based on a broader assessment of public safety – a more detailed evaluation should better prioritise the grouping and programming of defect rectification, as well as better inform the rectification timelines that should be applied to the different grades
- Aurora Energy’s vegetation management standard has adopted a ‘very high risk’ assessment for activities – a more complete risk assessment would help Aurora Energy optimise the timing of vegetation cutting.

## F.2.6 Findings

Aurora Energy is at an early stage of its asset management maturity journey, whereby it:

- is presently limited by the quality and completeness of its asset data (condition, performance, and attributes) to varying degree depending on the asset fleet
- has acknowledged and identified these issues and have improvement plans which will allow it to perform more advanced or refined risk assessments.

Such refined assessments will lead to defining mitigation measures with much greater precision.

Aurora Energy plans to improve its asset inspections, maintenance and record keeping activities. This should invariably result in improved data accuracy, completeness, and relevancy. This will then enable the implementation and functioning of efficient asset strategy including establishing and tracking of asset performance metrics.

Aurora Energy’s existing AMP and fleet strategies, planned improvements to those strategies, and proposed expenditure for the review period generally address the network risks identified by WSP in 2018 and are generally consistent with the recommendations. While the proposed expenditures are adequate in all the asset fleets that we have reviewed, there are some instances where we believe the proposal does not appear reasonable or should otherwise be addressed over the CPP and review periods. Such instances are identified in Table F.3 against each applicable asset fleet and further explained in Appendix C.

During our review, Aurora Energy has further refined, moderated and updated its proposed expenditure. In doing so, it has further aligned its asset strategies to the identified network risks.

## F.3 RISK REDUCTION TO ALARP

### F.3.1 Good practice

GEIP holds that high network risks are unacceptable and must be:

- eliminated
- reduced to an acceptable level (i.e. residual risk is insignificant), or
- reduced so that the residual risk is ALARP (i.e. residual risk is tolerable given the constraints).

At the core of the ALARP principle lies the concept of ‘reasonably practicable’ and ‘cost disproportion factor’ – and involves weighing a risk against the time, effort and money needed to eliminate or reduce it.

ALARP assessment requires a tolerable risk level to be set for decision making, exhaustive search for control measures, evaluation of alternatives with associated cost estimation, consideration of cost disproportionality, and comparison with the corresponding risk reduction to tolerable level. A corporate

risk management framework with risk appetite, action, escalation, and approval processes defines the tolerable risk level for decision making.

Effective ALARP assessments require underlying information, such as inherent risk level, residual risk level, cost estimates for implementing or delivering control measures, the various options of control measures, and determining if residual risk level is tolerable. The scope for ALARP assessments depends on the types and severity of consequence – where high consequence risks require a more thorough assessment compared to low consequence risks.

Aurora Energy's use of the ALARP principle across its asset fleets was – in several cases – not apparent when comparing the proposed control measures (i.e. renewal and maintenance strategies) against the corresponding reduction in the risk profile of a given fleet. We discuss this further in the next few sections

### F.3.2 Explicit demonstration

Explicit demonstration of applying the ALARP principle involves:

- proposing control measures
- evaluating options or alternatives for risk reduction
- estimating the corresponding costs
- recognising the residual risk is tolerable.

These variables – proposed project scope, cost estimate, risk assessment showing inherent, residual and tolerable risk levels – can be presented and weighed against each other for quantitative or qualitative analysis thereby demonstrating the ALARP principle in risk reduction in a visible manner.

In Aurora Energy's case, asset fleets that had expenditure forecast using condition- and consequence-based risk modelling *do* explicitly show that the ALARP principle was applied in its risk mitigation approach. As explained in previous sections, the zone substation power transformers and indoor switchgear asset fleet renewal models used this approach. Control measure expenditure forecasts were specifically optimised to mitigate or reduces the risk to a tolerable level – which can be seen in Aurora Energy's zone substation POD and the respective asset fleet risk models.

Criticality scoring in the risk models for these asset fleets include safety risks amongst other types of consequences. Safety risk – including its inclusion in the overall criticality score for these asset fleets – is documented in the zone substation POD and the respective asset fleet MODs. Safety risk for these asset fleets was determined using scorecards that were based on pre-defined parameters – such as protection speed and arc fault protection for indoor switchgear – which are good proxies to assess safety risks.

Condition and consequence-based risk modelling and expenditure forecasting processes provide advance visibility of the residual risk level after proposed mitigations are implemented. Risk reduction by every proposed mitigation action (project) is illustrated in Aurora Energy's 5×5 corporate risk matrix, which shows risk decreasing from the present intolerable zone (i.e. maroon or red coloured areas in the matrix) to tolerable zone. Accordingly, it is much easier to 'view' the ALARP application at CPP planning and independent verification stage for these asset fleets.

Appendix D includes our review of asset fleets that follow this risk methodology and expenditure forecasting approach, including as to how the ALARP principle has been used to inform risk reductions.

### F.3.3 Implicit demonstration

Implicit demonstration of applying the ALARP principle involves:

- aligning the proposed control measures with GEIP
- recognising the resulting level of risk reduction to tolerable level
- cost benchmarking.

Alignment with GEIP such as similar characteristics for asset expected lives, inspection, use of technology, methodology etc. is a good benchmark that implicitly incorporates evaluation of alternatives for similar risk reduction. Inherent, residual and tolerable risk levels are not directly apparent or visible in advance during the CPP planning and independent verification stage in these cases.

In Aurora Energy's case, asset fleets that had expenditure forecast using probabilistic- and age- based modelling methods *do* implicitly suggest that the ALARP principle was applied in its risk mitigation approach. As explained above, poles, crossarms, conductors, LV enclosures and outdoor circuit breaker asset fleets follow this approach – which is covered in the respective asset fleet PODs and MODs.

For these fleets, criticality or consequence was not directly considered when forecasting forecast expenditure. Rather, Aurora Energy's intent is to use criticality or consequence to prioritise mitigation measures closer to when they are forecast to occur once further inspection is undertaken. Criticality scoring for these asset fleets included safety risk consequence only and are determined using pre-defined population density and proximity to asset parameters.

Risk modelling of these asset fleet included:

- analysis of historical risk mitigation practices (asset survivor curve)
- assuming that asset age was a reasonable proxy for the probability of asset failure, with expected asset life representing the point deemed to be where the risk is above ALARP.

In both instances, asset health – or AHI profile – of the asset fleet was calculated and used in the relevant renewal modelling approach. This calculated AHI profile was treated as a risk level proxy for the asset fleet where the assets with poor health have risks above ALARP.

Assumed probability distributions and parameters – such as distribution type and standard deviation – applied in an asset survivor curve incorporate margins of risk tolerability between the required replacement age and actual unassisted failures. This implies that the ALARP principle *is* captured within the modelling. Comparing the survivor curve and the asset expected age for a given asset fleet against assumptions and information widely used across the electricity distribution industry also suggests that the ALARP principle has been reflected in the resulting expenditure forecast.

For a given fleet, any risk reduction achieved by the proposed mitigation actions is proxied by the change – or improvement – shown in the AHI profile. Inherent and residual AHI profiles of the fleet are illustrated in the respective PODs. AHI profiles with different expenditure options can give the implicit residual risk by the % of assets with AH1.

Nevertheless, although we can *infer* whether ALARP was reflected in the expenditure forecasts, we could not confirm that ALARP *was* applied in CPP planning for these fleets. To draw inferences, we benchmarked Aurora Energy's forecasts against other EDBs to assess whether the inherent risk has been reasonably addressed against costs and reduced to tolerable level. For instance, we compared the per annum asset renewal rate against failure rate or risk (age) profile.

Appendix D includes our review of asset fleets that follow this risk methodology and expenditure forecasting approach, including as to whether we can infer that forecasts reflected the ALARP principle.

# Appendix G Expenditure benchmarking

## G.1 OVERVIEW

Benchmarking can be a useful tool for assessing whether actual and proposed expenditure is efficient relative to other networks. This appendix seeks to benchmark Aurora Energy against other New Zealand EDBs, including on network characteristics, total expenditure, opex, and capex. Some benchmarking is also included in other parts of our report.

After undertaking our own benchmarking and reviewing that provided by Aurora Energy, our key findings are that:

- Aurora Energy’s network characteristics (e.g. customer numbers, circuit length, and customer density) are typical of some larger New Zealand EDBs – however, the unique characteristics across many EDBs makes it hard to draw reliable conclusions from benchmarking against other New Zealand EDBs<sup>315</sup>
- there are some anomalies in the New Zealand EDB benchmarking dataset that may undermine our benchmarking analysis, particularly how the EDBs have assigned data to each schedule, category and sub-category and leading to the potential for double count counting
- Aurora Energy’s *average* total expenditure, opex and capex over the 2013–2019 period are comparable to that of other large New Zealand EDBs – however, the increase over the last few years of that period and that proposed in the CPP proposal raise Aurora Energy’s expenditure, on a per unit basis, above its peers in most cases and away from the trend line of all EDBs (although we note that this comparison is subject to significant limitations)
- the asset replacement and renewal expenditure is shown to have been increasing over the 2013–2019 period when normalised by customer density and by 2019 was significantly higher than that of other large New Zealand EDBs
- Aurora Energy’s SAIDI and SAIFI performance is consistent with that of the larger New Zealand EDBs, but has increased noticeably over the 2013–2019 period.

We have not undertaken any economic benchmarking, such as that used by the AER, because we do not consider the New Zealand EDBs are sufficiently comparable to rely on the outputs of such benchmarking and there remains significant debate over the economic models that underpin the benchmarking in any case.<sup>316</sup> We are also not confident that adding data from electricity distribution networks operating in other jurisdictions – which is needed to apply that benchmarking – will improve the accuracy of the analysis.

## G.2 NETWORK CHARACTERISTICS

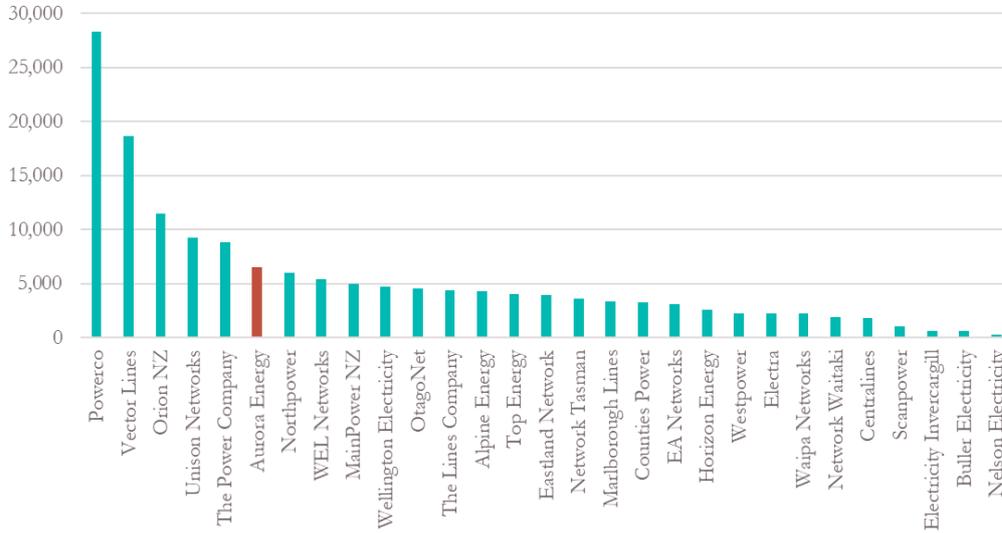
This section compares the network characteristics of Aurora Energy to other New Zealand EDBs. The graphs that follow show that Aurora Energy is roughly the 6<sup>th</sup> or 7<sup>th</sup> largest EDB in terms of circuit length, customer numbers and maximum coincident system demand – which has been consistent over the

<sup>315</sup> A trend line has been added to the scatter plots to identify the level of expenditure that would currently be considered as efficient relative to the other EDBs, given the historical levels of expenditure and characteristics in the data set. This does not mean that EDBs on that line are operating efficiently, but shows that is where EDBs of similar characteristics would be expected to be found. The R2 value has been displayed to show how well the trend line fits the underlying data set. A value of zero indicates no relationship and a value of one indicates a perfect relationship.

<sup>316</sup> See, for instance, Australian Competition Tribunal, Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, at paras [115] to [497].

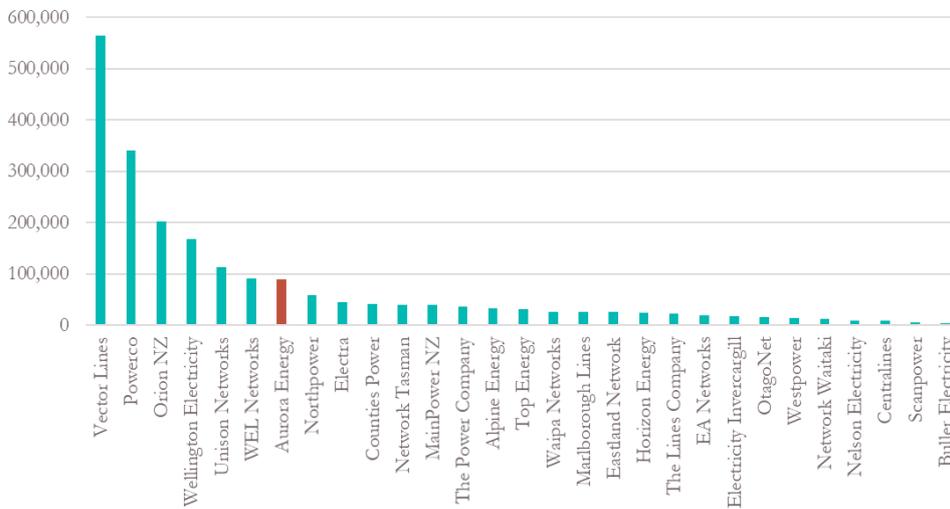
2013–2019 period. Given its mix of urban and rural areas, Aurora Energy also has moderate customer density.

Figure G.1: Circuit length (km)



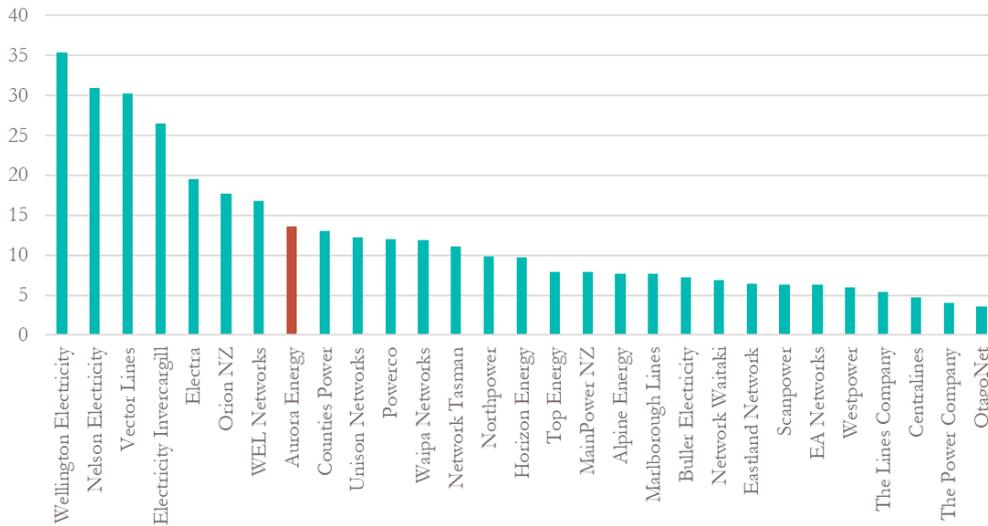
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.2: Customer numbers (# ICPs)



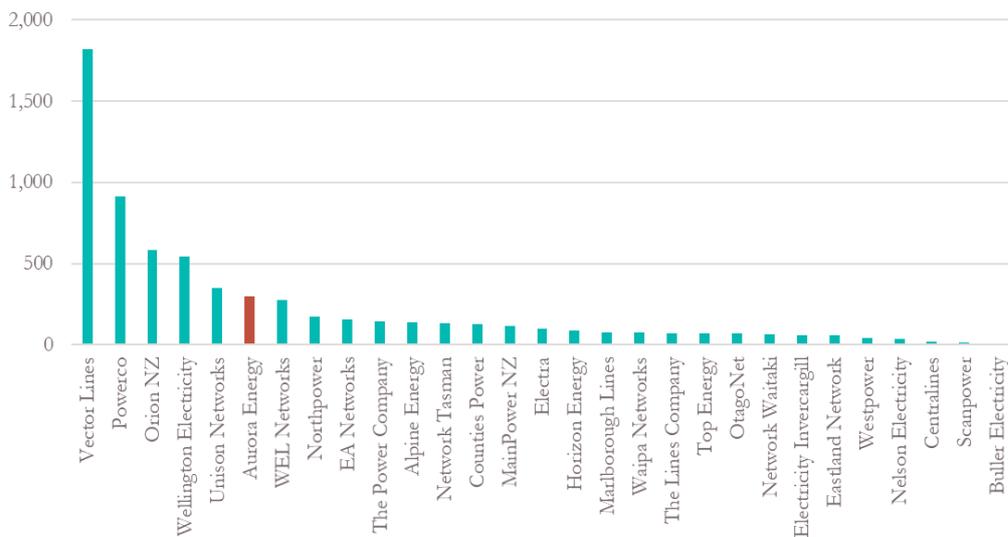
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.3: Customer density (ICPs / km)



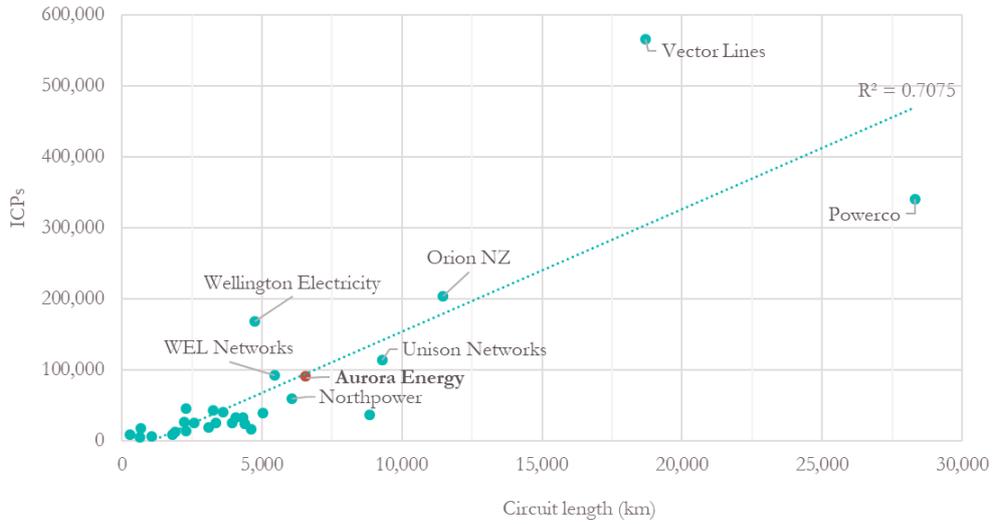
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.4: Maximum coincident system demand (MW)



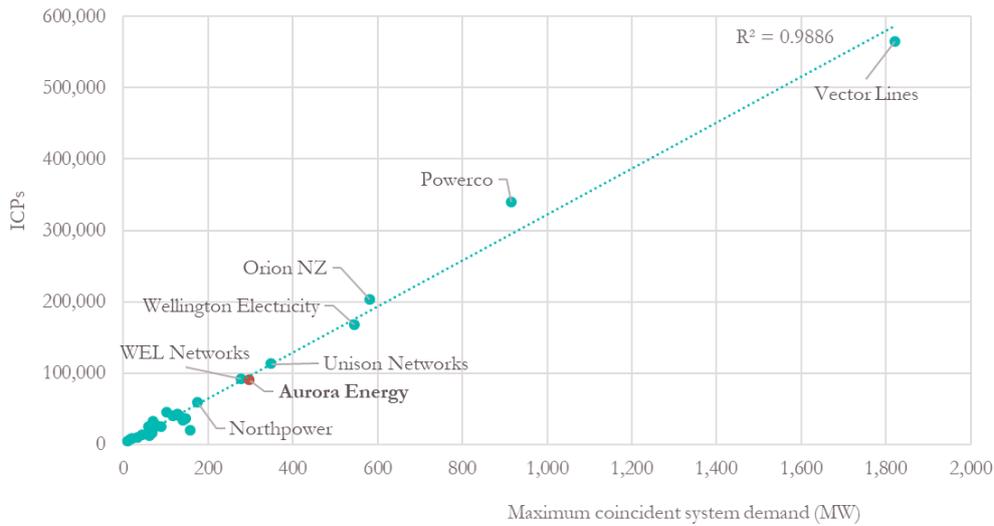
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.5: Circuit length (km) vs customers



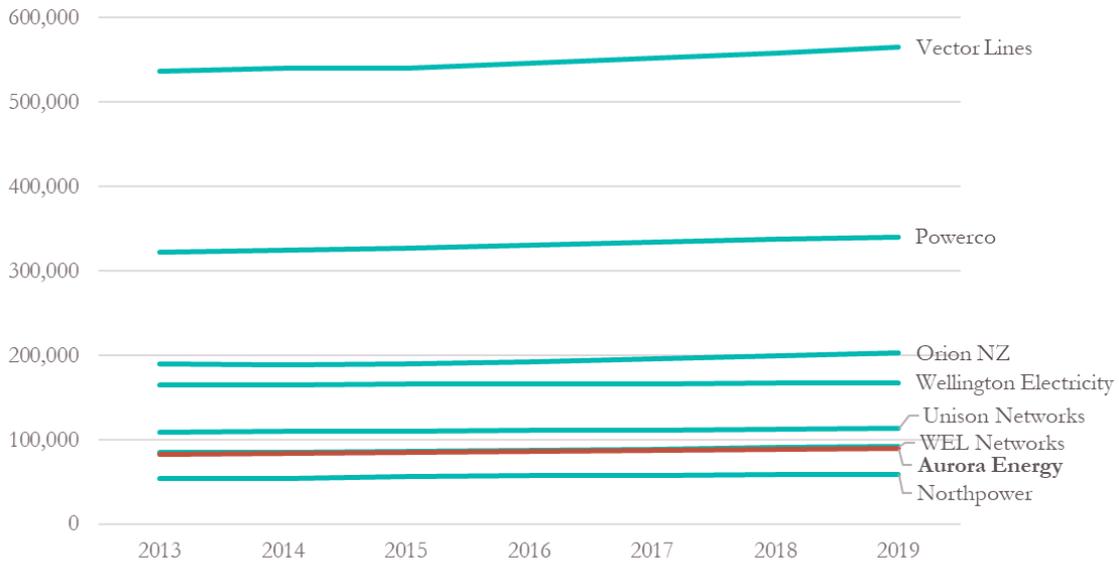
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.6: Maximum coincident system demand (MW) vs customers (ICPs)



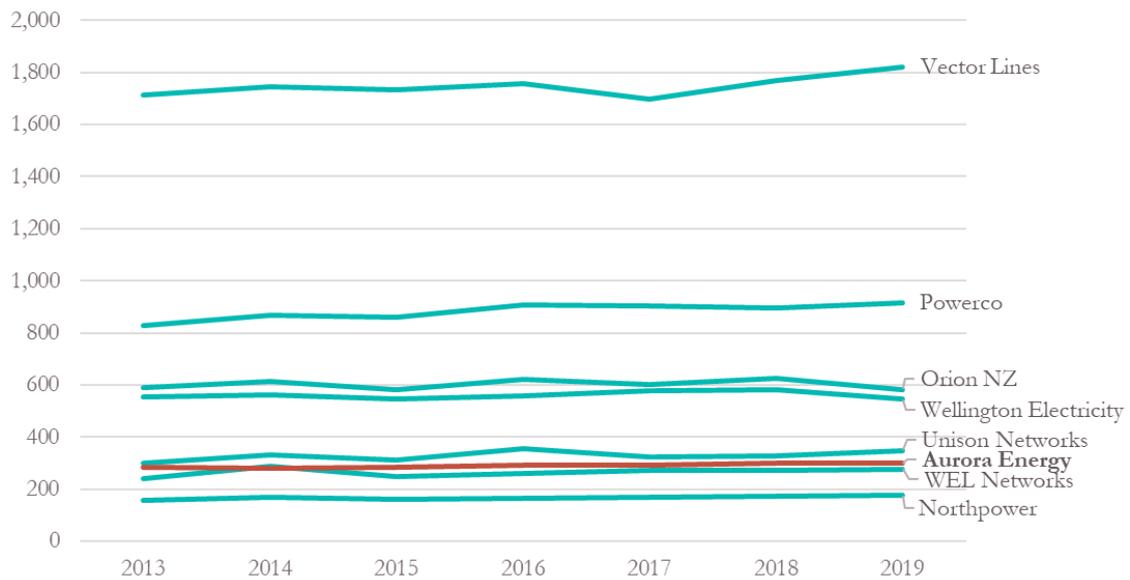
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2019 information disclosures.

Figure G.7: Customers (ICPs) for the largest networks, 2013 – 2019



Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2013 – 2019 information disclosures and is calculated by multiplying customer density by circuit line length.

Figure G.8: Maximum coincidence system demand (MW) for largest networks, 2013 – 2019



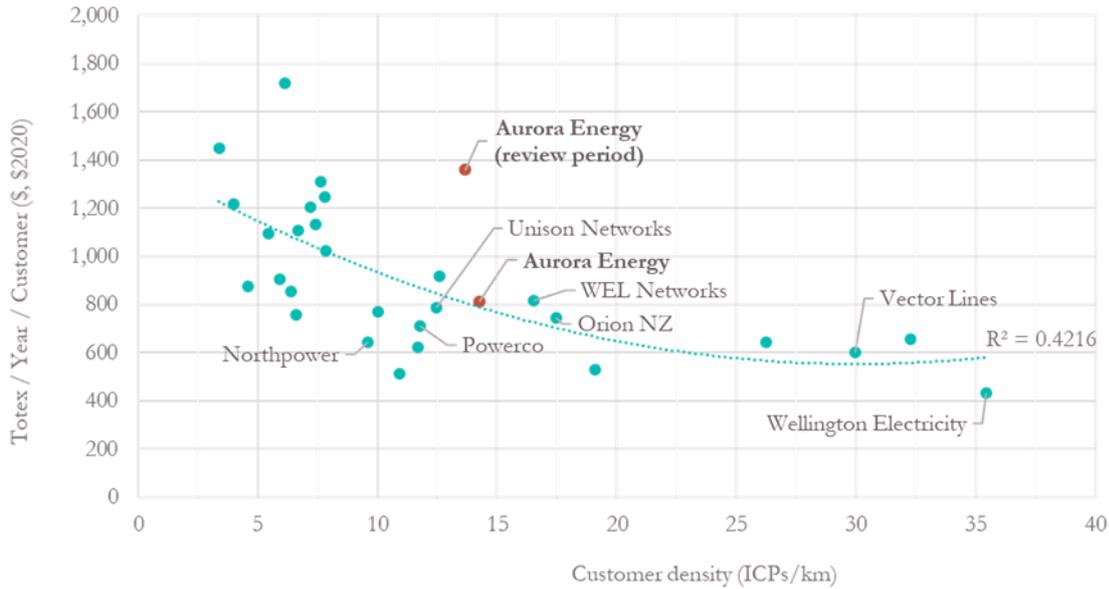
Source: Commerce Commission, Information Disclosure data base. Data is as included in the 2013 – 2019 information disclosures.

### G.3 TOTAL EXPENDITURE

This section compares Aurora Energy’s total expenditure to other New Zealand EDBs. The graphs show that Aurora Energy’s average expenditure over the 2013–2019 period is consistent with that of the other larger EDBs, when looked at on a per customer (i.e. per ICP), per MW of coincident maximum system

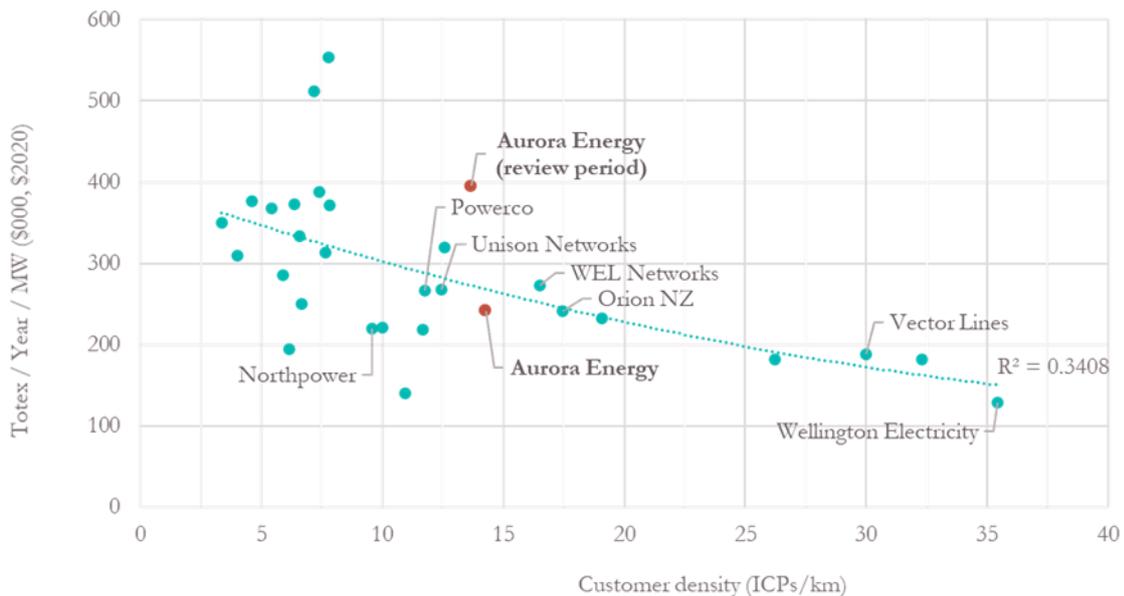
demand, and per km of circuit line length.<sup>317</sup> However, Aurora Energy’s increase in expenditure over the latter part of that period pushes it noticeably above those EDB peers. In all graphs, Aurora Energy’s proposed expenditure for the review period pushes it significantly above what was observed over the 2013–19 period.

Figure G.9: Total expenditure per year per customer vs customer density (ICPs / km)



Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. Total expenditure is calculated as the sum of expenditure on assets and operating expenditure.

Figure G.10: Total expenditure per year per MW vs customer density (ICPs / km)

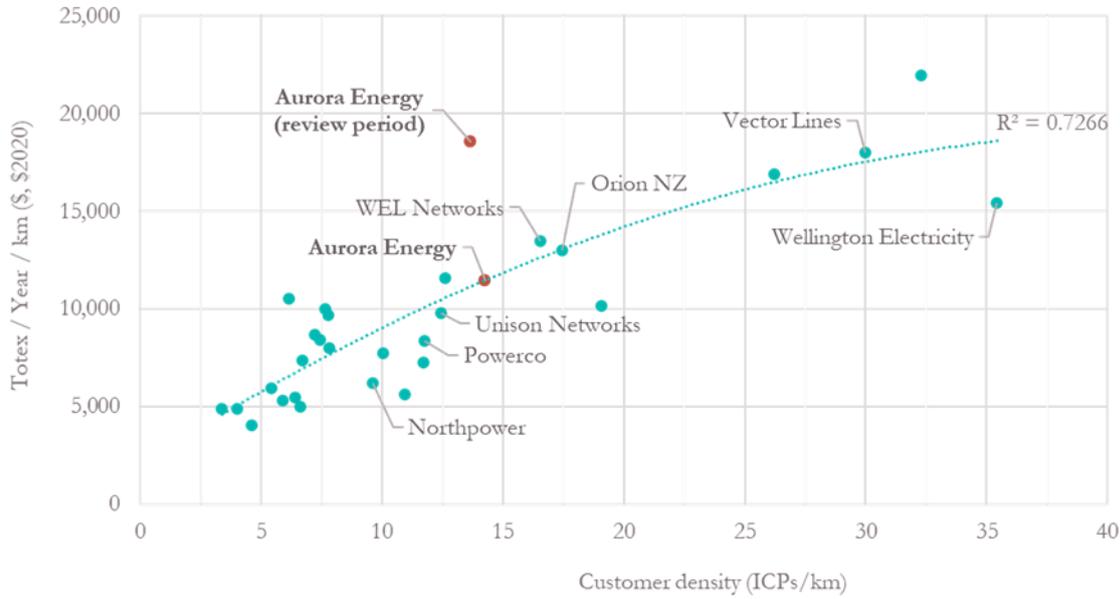


Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19

<sup>317</sup> For comparison purposes, we refer to Aurora Energy, Northpower, Orion NZ, Powerco, Unison Networks, Wellington Electricity, WEL Networks and Vector Lines as the ‘larger EDBs’.

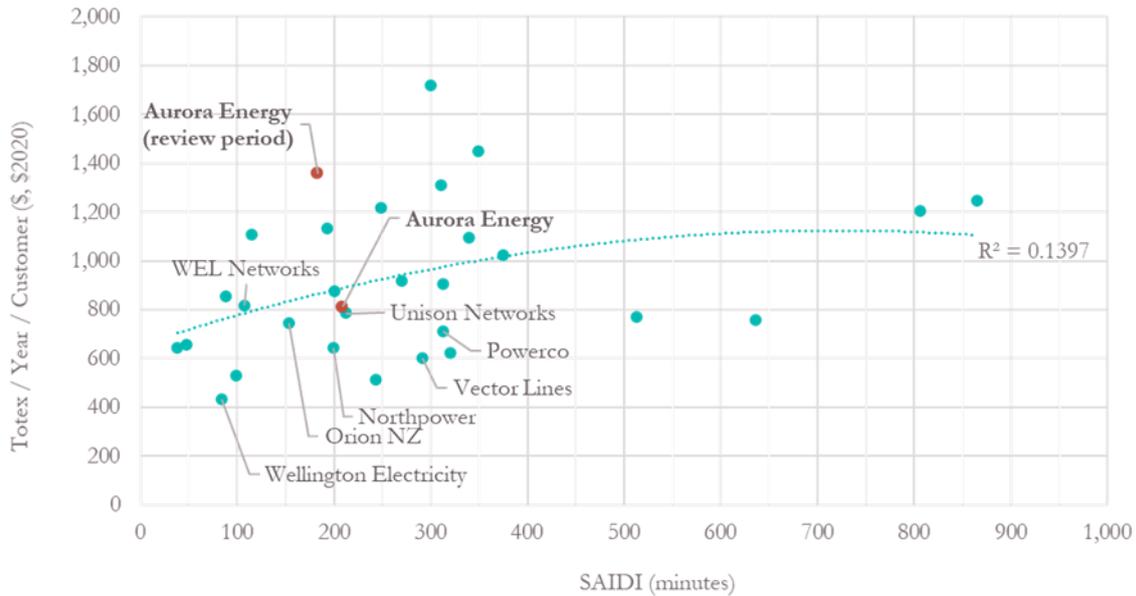
levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.11: Total expenditure per year per km vs customer density (ICPs / km)



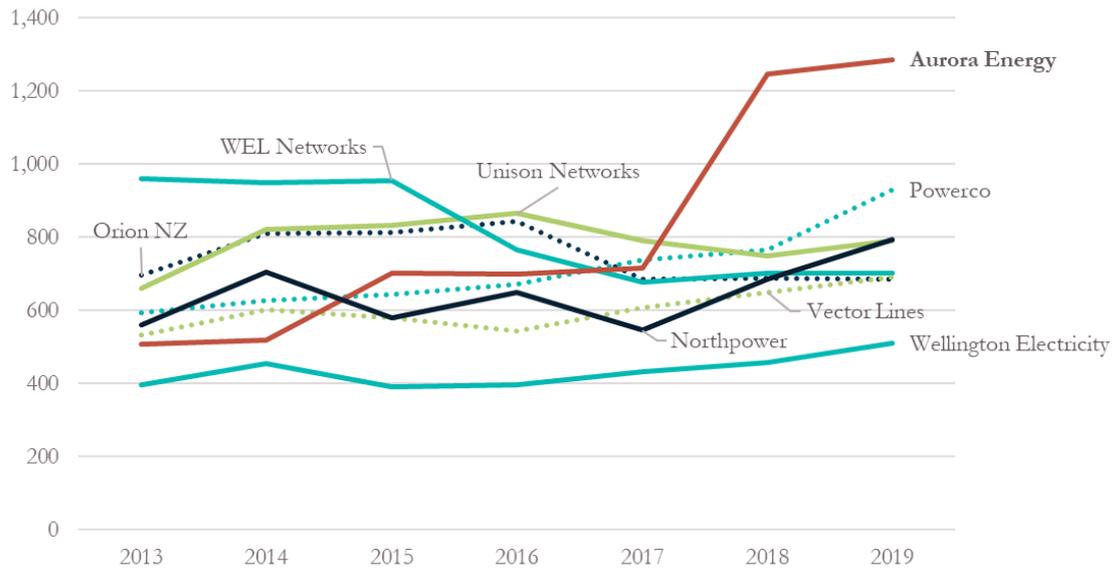
Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.12: Total expenditure per year per customer vs customer minutes off supply (SAIDI)



Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.13: Total expenditure per year per customer, 2013–2019

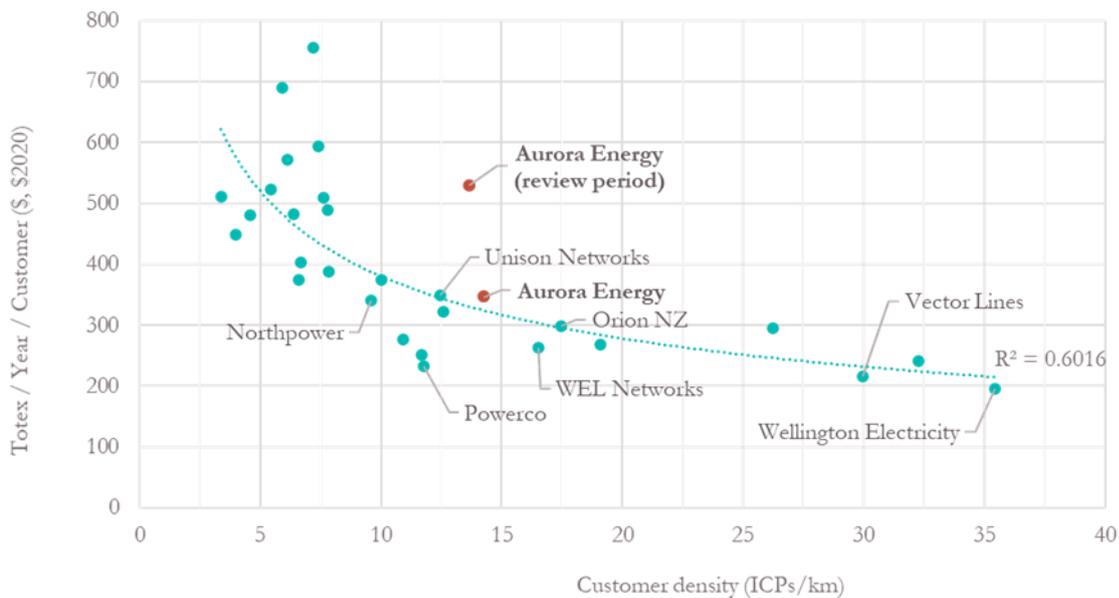


Source: Commerce Commission, Information Disclosure data base. Expenditure is in \$2020.

### G.4 OPERATING EXPENDITURE

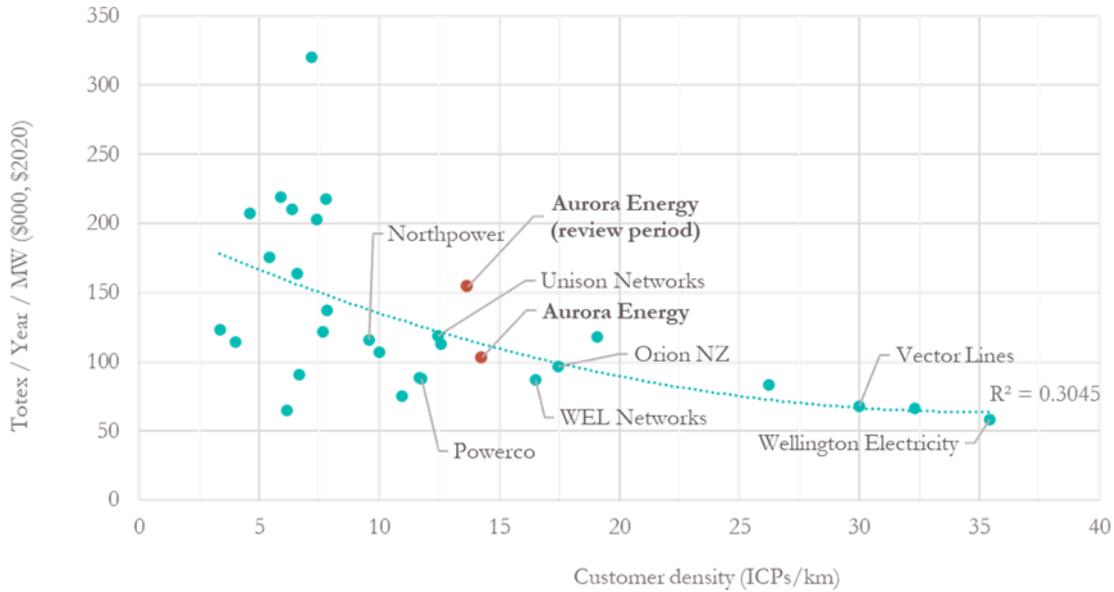
This section compares Aurora Energy’s operating expenditure to other New Zealand EDBs. The graphs show that Aurora Energy’s average operating expenditure over the 2013–2019 period is consistent with that of the other larger networks. The increase in expenditure over the latter part of the period is also evident and – in the case of operating expenditure – appears to track a similar increase experienced by Northpower. The graphs also show that operating expenditure per customer has increased over the 2013–2019 period. In all graphs, Aurora Energy’s proposed opex for the review period pushes it significantly above what was observed over the 2013–19 period.

Figure G.14: Opex per year per customer vs customer density (ICPs / km)



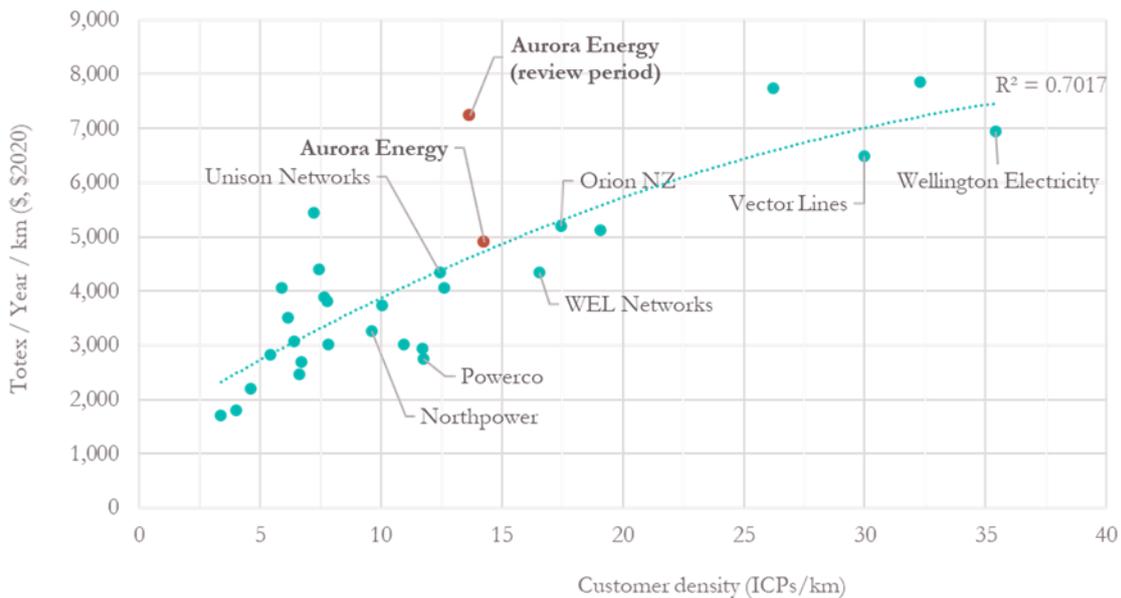
Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.15: Opex per year per MW vs customer density (ICPs / km)



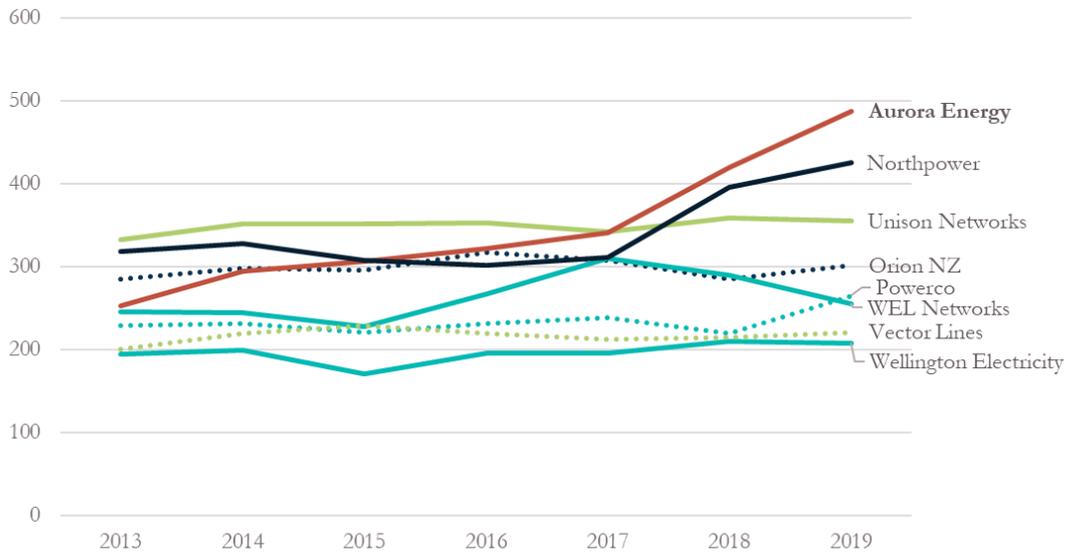
Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.16: Opex per year per km vs customer density (ICPs / km)



Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.17: Opex per year per customer, 2013–2019

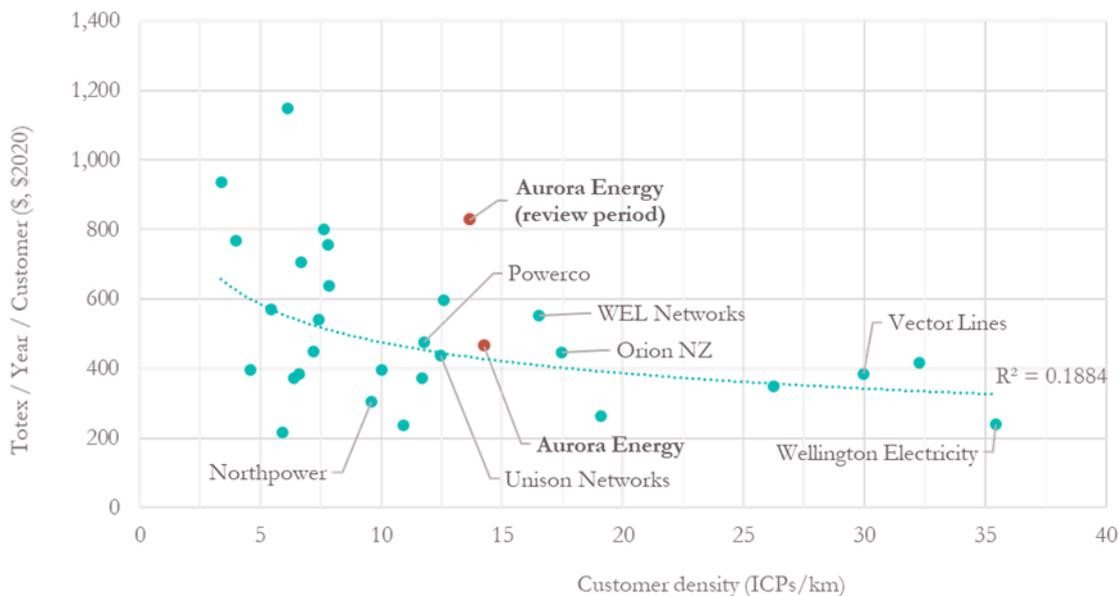


Source: Commerce Commission, Information Disclosure data base. Expenditure is in \$2020.

## G.5 CAPITAL EXPENDITURE

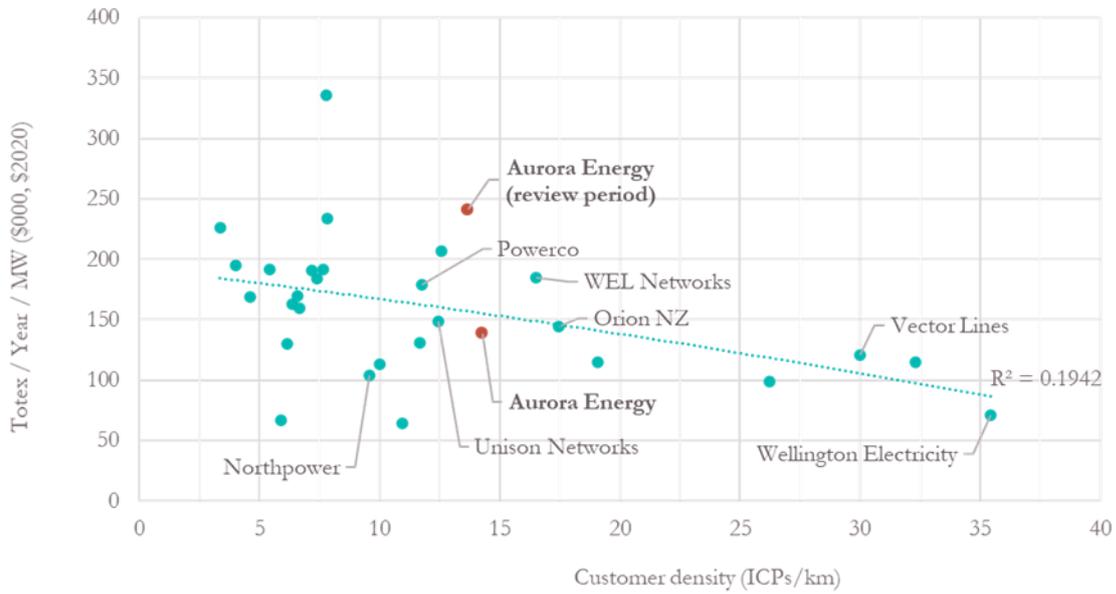
This section compares Aurora Energy’s capital expenditure to other New Zealand EDBs. As with operating expenditure, the graphs show that Aurora Energy’s average capital expenditure over the 2013–2019 period is consistent with that of the other larger networks, again with a noticeable step up in expenditure over the latter part of the period. The graphs also show that Aurora Energy’s capital expenditure per customer has steadily increased over the 2013–2019 period.

Figure G.18: Capex per year per customer vs customer density (ICPs / km)



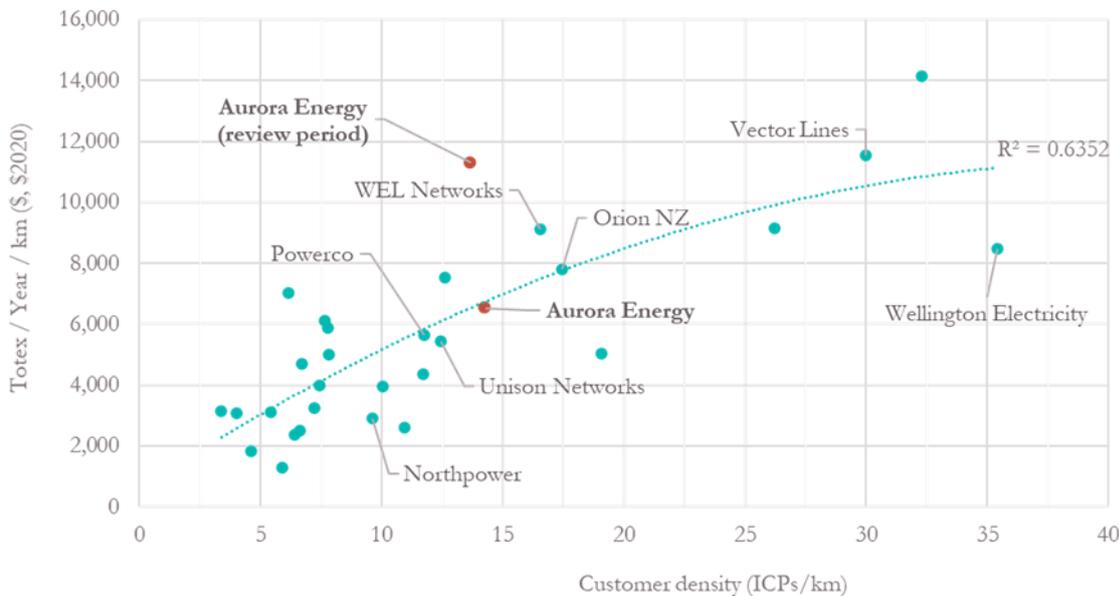
Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.19: Capex per year per MW vs customer density (ICPs / km)



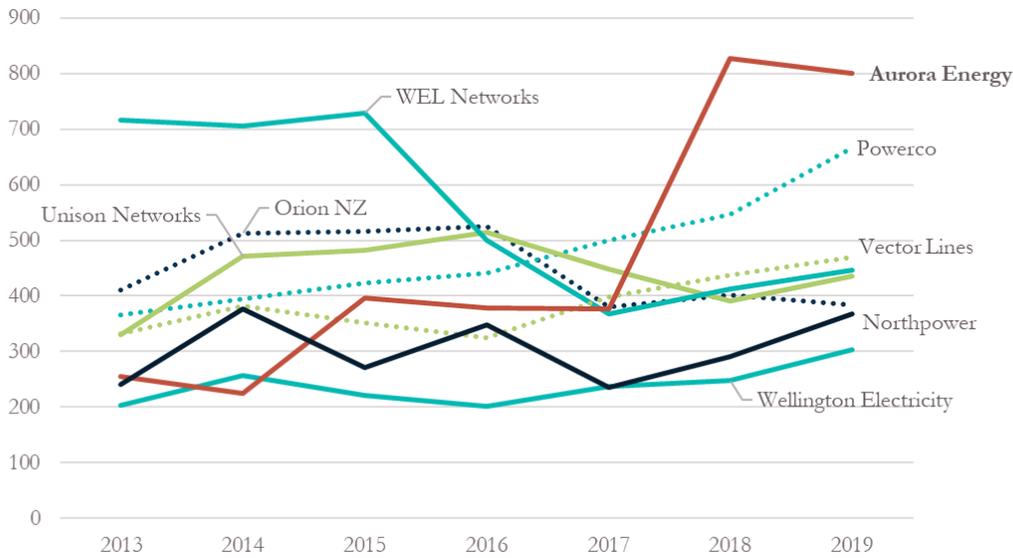
Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.20: Capex per year per km vs customer density (ICPs / km)



Source: Commerce Commission, Information Disclosure data base. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

Figure G.21: Capex per year per customer, 2013–2019



Source: Commerce Commission, Information Disclosure data base. Expenditure is in \$2020.

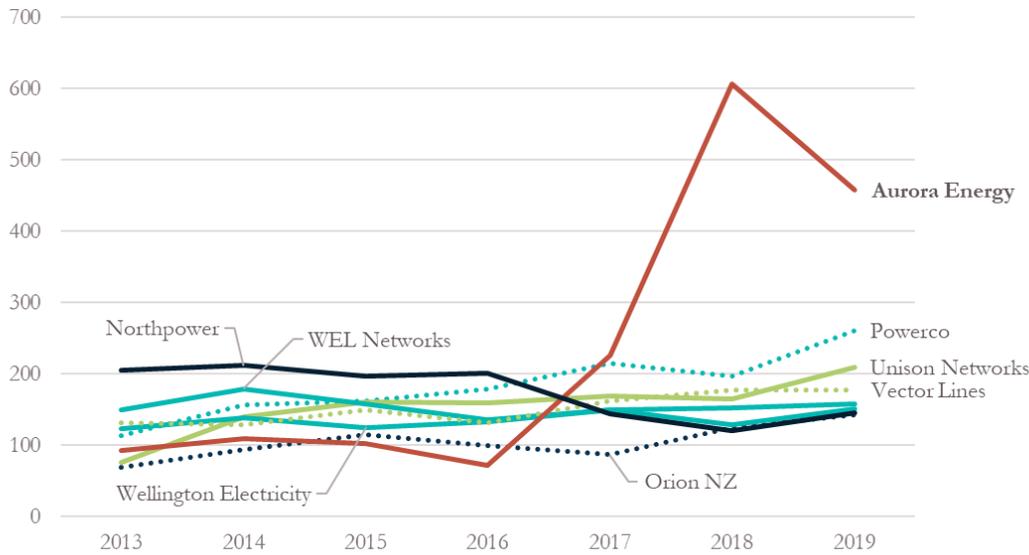
## G.6 REPLACEMENT AND RENEWAL EXPENDITURE

This section compares Aurora Energy’s replacement and renewal expenditure (repex) to other New Zealand EDBs. The graphs show that Aurora Energy’s average replacement expenditure over the 2013–2019 period has increased significantly over the period. Although at the start of the period Aurora Energy’s repex was in-line with that of other larger EDBs, it was significantly higher by the end of the period – which is consistent with Aurora Energy’s focus on replacing aging and failing assets.

The proposed expenditure in the CPP forecast is expected to maintain this higher level and will result in average expenditure of approximately \$597.3 per customer over the review period, which would place Aurora Energy well above its peers in the benchmarking analysis.

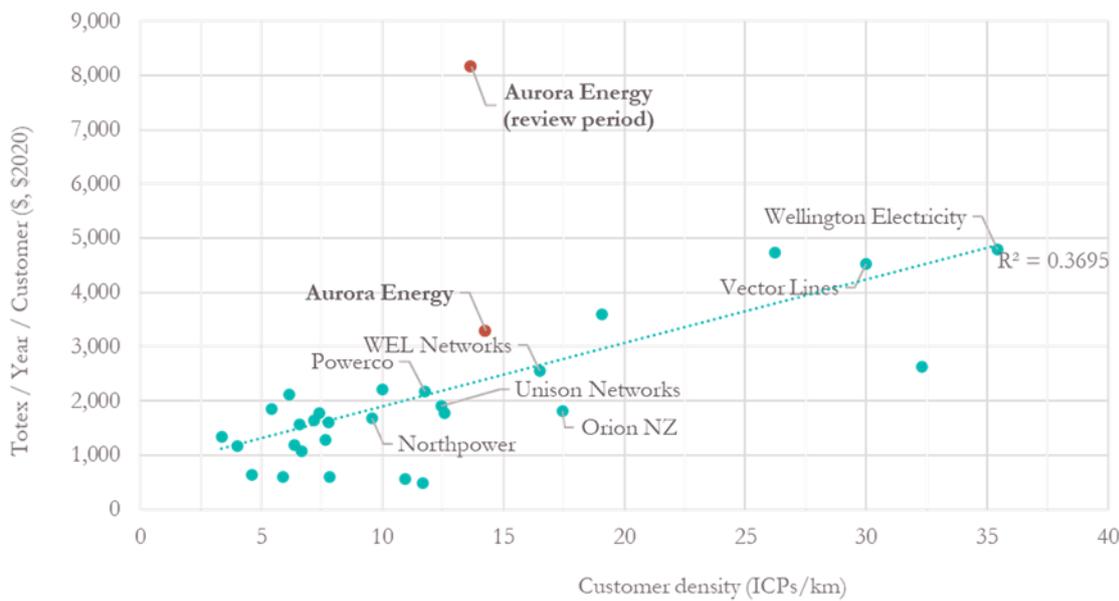
The forecast repex per year per circuit kilometre was compared against customer density to demonstrate the relationship between unit costs while controlling for rural and urban networks. The chart shows a R value indicating a reasonable fit of the trend line with the data. It shows that although Aurora Energy’s repex was below that of most comparator EDBs up until RY16, its repex has increased significantly since then with the most recent spend being well above them.

Figure G.22: Repex per year per customer, 2013 – 2019, \$ per customer



Source: Commerce Commission, Information Disclosure data base. Expenditure is in \$2020.

Figure G.23: Repex per year per km vs customer density

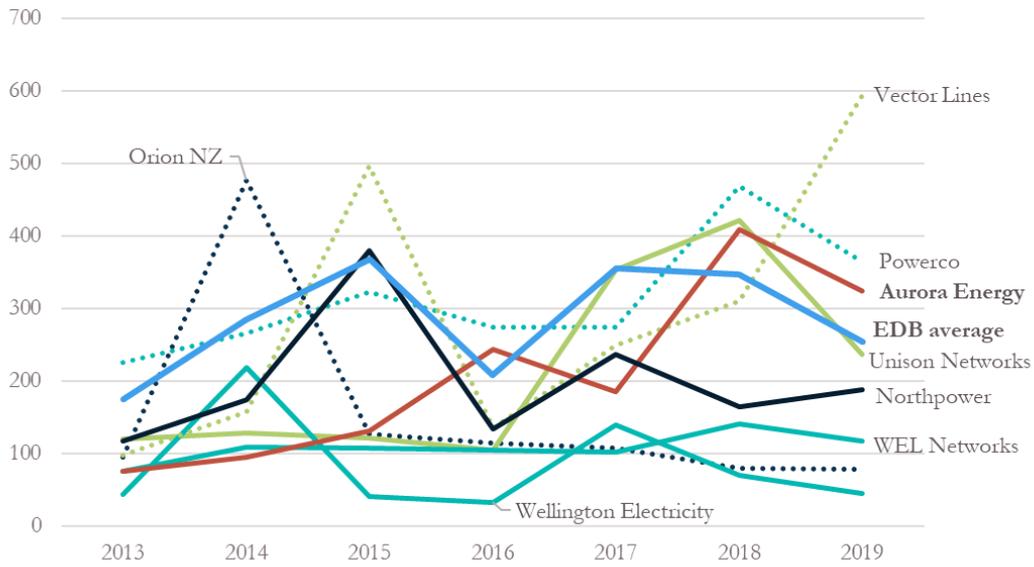


Source: Commerce Commission, Information Disclosure data base. Expenditure is in \$2020. Data is averaged over the 2013–2019 information disclosures. For presentation purposes, Aurora Energy’s customer density is assumed to stay constant at RY19 levels over the CPP and review periods, and customer numbers and circuit line length are forecast to increase by a notional 1% per year from RY19 levels.

## G.7 RELIABILITY

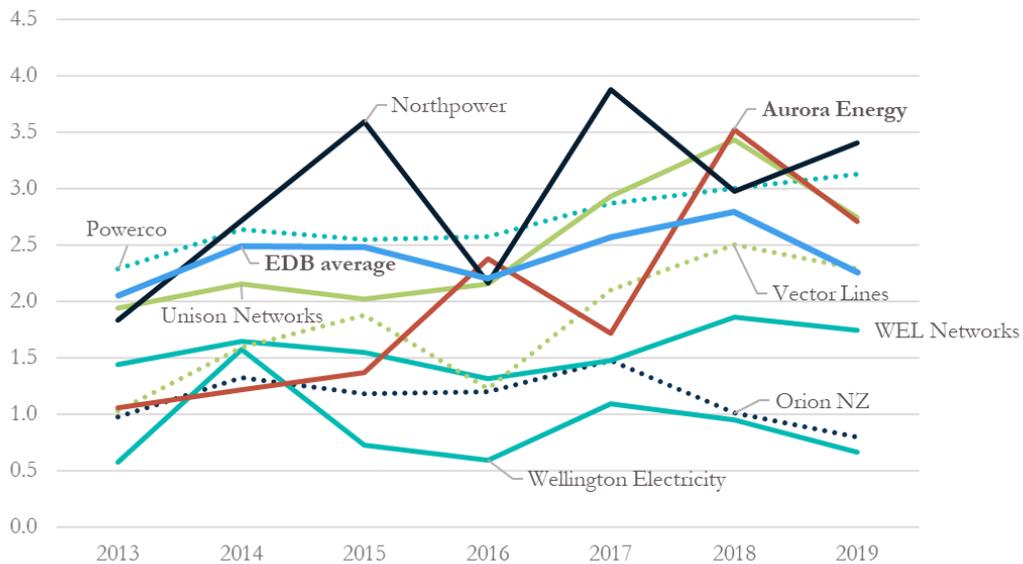
This section compares Aurora Energy’s SAIDI and SAIFI performance to other New Zealand EDBs. The graphs show that Aurora Energy’s SAIDI and SAIFI have increased noticeably over the period, but remain consistent with other larger EDBs and the EDB average.

Figure G.24: SAIDI (minutes), 2013–2019



Source: Commerce Commission, Information Disclosure data base.

Figure G.25: SAIFI (number of outages), 2013–2019



Source: Commerce Commission, Information Disclosure data base.

## Appendix H Verification certificate

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I certify that:

1. the relevant parts of the customised price path proposal prepared by Aurora Limited and dated 12 June 2020 have been verified by Farrier Swier Consulting Pty Ltd and a verification report was prepared in accordance with Schedule G of the Electricity Distribution Services Input Methodology Amendments Determination (No. 2) 2019; and
2. the findings from this verification are documented in the report titled *Verification report – Aurora Energy CPP application* and dated 8 June 2020 prepared by Farrier Swier Consulting Pty Ltd and GHD Pty Ltd.

This certificate is provided in accordance with the requirements of clause 5.1.3(1)(d) of the Commerce Commissions Electricity Distribution Services Input Methodology Amendments Determination (No. 2) 2019.



Shaun Dennison

**Director**

Farrier Swier Consulting Pty Ltd

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I certify that:

1. GHD Pty Ltd assisted Farrier Swier Consulting Pty Ltd by reviewing and assessing the relevant technical aspects of the customised price path proposal prepared by Aurora Limited and dated 12 June 2020, including verifying capital and operational programs and projects; and
2. the findings from this verification are documented in the Farrier Swier Consulting Pty Ltd report titled *Verification report – Aurora Energy CPP application* and dated 8 June 2020.



Stephen Hinchliffe

**Leader – Regulation and Access**

GHD Pty Ltd

# Appendix I Information provided

This appendix lists the documents and spreadsheets provided by Aurora Energy to us via the SharePoint site, and which we had regard to when preparing our verification report, and is split as follows:

- Table I.1 lists the information provided by Aurora Energy – we have cited throughout this report the information that we have relied upon in developing our findings
- Table I.2 lists our question to Aurora Energy and responses to them that we have relied upon when developing our report
- Table I.3 lists the responses to our draft report provided by Aurora Energy via the SharePoint site which we have considered in completing our final report<sup>318</sup> – this information is also cited by us where relevant throughout the report
- Table I.4 lists the other information provided by Aurora Energy that informed the report
- Table I.5 lists the information that we relied upon that was not provided by Aurora Energy.

For each item listed, the tables identify the document reference (where applicable), the document name, and the date it was uploaded to the SharePoint site. Note, due to how SharePoint assigns identification numbers within document libraries there are gaps in the number sequencing of documents set out below.

**Table I.1: Information provided by Aurora Energy via the SharePoint site**

Document id	Document type	Type id	Document name	Date uploaded
C-1118	Site documentation	9.1.2	CPP Verifier Review Site Procedures.docx	29/11/2019
C-1120	Site documentation	9.1.2	Documents In Draft within CDS.xlsx	12/12/2019
C-1121	Meeting Minutes - Tripartite meeting	9.1.2	20191113 Minutes - Verifier Tripartite Meeting - November 2019 - (FINAL).pdf	20/12/2019
C-1122	Meeting Minutes - Tripartite meeting	9.1.2	20191009 Minutes- Verifier Tripartite Meeting September 2019 - FINAL (v2).pdf	20/12/2019
C-1325	Collateral from Tripartite Meeting	9.1.2	Aurora Technology Principles to Share.pptx	20/12/2019
C-1326	Collateral from Tripartite Meeting	2.1.4	191218 ISO 55001 summary.pptx	20/12/2019
C-1327	Collateral from Tripartite Meeting	2.1.4	191218 Risk Summary slides for Tripartite meeting 19 December.pptx	20/12/2019
C-1329	Collateral from Tripartite Meeting	9.1.1	191218 Overhead Network Condition Inspection Overview.pptx	20/12/2019

<sup>318</sup> This includes feedback provided on our penultimate draft report circulated to Aurora Energy on 22 May 2020.

Document id	Document type	Type id	Document name	Date uploaded
C-1330	Collateral from Tripartite Meeting	9.1.2	20191219 CPP Programme Update.pptx	20/12/2019
C-1332	Collateral from Tripartite Meeting	8.1.3	Customer_Advisory_Panel_response_to_Aurora_Energy_CPP_consultation_document.pdf	29/01/2020
C-1334	Collateral from Tripartite Meeting	9.1.1	Aurora Natural Hazards Exposure Report - FINAL20200124.pdf	24/01/2020
C-1335	Site documentation	9.1.1	Aurora List of Information to Deliver to farrierswier - Info Pack 1 - CDS Approved documents.xlsx	18/02/2020
C-1338	Site documentation	9.1.2	Info Pack 1 - CDS Approved Policies and Planning Standards.xlsx	17/02/2020
C-1340	Meeting Minutes - Tripartite meeting	9.1.2	20191219 Minutes - Verifier Tripartite Meeting - December 2019 (FINAL).pdf	18/02/2020
C-1341	Collateral from Tripartite Meeting	9.1.2	20200217 Verifier Meeting 17 February 2020.pptx	20/02/2020
C-1343	Collateral from Tripartite Meeting	9.1.1	2019 Aurora Review T Stevenson 190220.pdf	24/02/2020
C-1344	Meeting Minutes - Tripartite meeting	9.1.2	20200217 Meeting Minutes - Verifier Tripartite Meeting - February 2020 - FINAL.pdf	30/03/2020
C-4	Collateral from Tripartite Meeting	2.1.4	201904 Aurora+D2:D19 Health Safety and Risk Assessment Workshop BOARD FINAL with Appendix v2.pdf	26/07/2019
C-5	Meeting Minutes - Tripartite meeting	9.1.2	20190703 Meeting Minutes, Verifier Establishment Meeting (FINAL).pdf	25/07/2019
C-8	Identified Programmes	1.3.1	Identified Programme Analysis for IV .xlsx	29/11/2019
E-7	Model	5.1.7	MOD18 - LV Enclosures Renewals Forecast.xlsx	21/02/20
E-8	Portfolio Overview Document (POD)	6.2.3	POD18 - LV Enclosures.pdf	21/02/20
E-9	Customised Estimate	6.2.1	MOD31 - Arrowtown 33kV Ring Upgrade - Customised Estimate.xlsx	21/02/20

Document id	Document type	Type id	Document name	Date uploaded
E-10	Model	6.2.1	MOD31 - Arrowtown 33kV Ring Upgrade - Economic Evaluation.xlsx	21/02/20
E-11	Portfolio Overview Document (POD)	6.2.3	POD31 - Arrowtown 33kV Ring Upgrade.pdf	21/02/20
E-12	Model	5.1.4	MOD72 - Reactive Maintenance Forecast Model.xlsx	21/02/2018
E-13	Portfolio Overview Document (POD)	6.2.3	POD72 - Reactive Maintenance.pdf	21/02/20
E-14	Model	5.1.7	MOD02 - Crossarms Renewal Forecast.xlsx	27/02/20
E-15	Model	5.1.7	MOD04 - Distribution Conductors Renewals Forecast.xlsx	27/02/20
E-16	Portfolio Overview Document (POD)	6.2.3	POD02 - Crossarms.pdf	27/02/20
E-17	Portfolio Overview Document (POD)	6.2.3	POD04 - Distribution Conductor.pdf	27/02/20
E-18	Model	5.1.7	MOD24 - Protection Relays Renewal Forecast.xlsx	27/02/20
E-19	Portfolio Overview Document (POD)	6.2.3	POD24 - Protection.pdf	27/02/20
E-20	Customised Estimate	6.2.1	MOD34 - Riverbank Zone Substation Upgrade - Customised Estimate.xlsx	27/02/20
E-21	Model	6.2.1	MOD34 - Riverbank Zone Substation Upgrade - Economic Evaluation.xlsx	27/02/20
E-22	Portfolio Overview Document (POD)	6.2.3	POD34 - Riverbank Zone Substation Upgrade.pdf	27/02/20
E-23	Portfolio Overview Document (POD)	6.2.3	POD71 - Corrective Maintenance.pdf	27/02/20
E-24	Model	5.1.4	MOD71 - Corrective Maintenance Forecast Model.xlsx	27/02/20
E-25	Portfolio Overview Document (POD)	6.2.3	POD50 - Consumer Connection.pdf	27/02/20
E-26	Model	5.1.1	MOD50 - Consumer Connection Forecast Model.xlsx	27/02/20
E-27	Model	5.1.7	MOD01 - Poles Renewals Forecast.xlsx	28/02/20

Document id	Document type	Type id	Document name	Date uploaded
E-28	Portfolio Overview Document (POD)	6.2.3	POD01 - Poles.pdf	28/02/20
E-29	Portfolio Overview Document (POD)	6.2.3	POD05 - LV Conductor.pdf	28/02/20
E-30	Model	5.1.7	MOD05 - LV Conductors Renewals Forecast.xlsx	28/02/20
E-31	Model	5.1.4	MOD70 - Preventive Maintenance Forecast Model.xlsx	28/02/20
E-32	Portfolio Overview Document (POD)	6.2.3	POD70 - Preventive Maintenance.pdf	28/02/20
E-33	Model	7.1.1	SUPERSEDED - MOD80 - SONS Forecast Model.xlsx	28/02/20
E-34	Model	7.1.1	SUPERSEDED - MOD81 - People Cost Forecast Model.xlsx	28/02/20
E-35	Portfolio Overview Document (POD)	6.2.3	POD80 - SONS.pdf	28/02/20
E-36	Portfolio Overview Document (POD)	6.2.3	POD81 - PEOPLE.pdf	28/02/20
E-37	Model	5.1.7	MOD09 - Zone Substation Coordination Model.xlsx	28/02/20
E-38	Portfolio Overview Document (POD)	6.2.3	POD09 - Zone Substations.pdf	28/02/20
E-40	Customised Estimate	6.2.2	MOD09 - 01 - Alexandra 33 kV Outdoor-Indoor Conversion.xlsx	28/02/20
E-41	Customised Estimate	6.2.2	MOD09 - 02 - Andersons Bay Substation Rebuild.xlsx	28/02/20
E-42	Customised Estimate	6.2.2	MOD09 - 03 - Arrowtown Transformer and Outdoor 11kV Switchgear Replacement.xlsx	28/02/20
E-43	Customised Estimate	6.2.2	MOD09 - 04 - Green Island Substation Rebuild.xlsx	28/02/20
E-44	Customised Estimate	6.2.2	MOD09 - 06 - Queenstown 33 kV Outdoor Switchyard Renewal.xlsx	28/02/20
E-45	Customised Estimate	6.2.2	MOD09 - 05 - Port Chalmers Transformer Replacement.xlsx	28/02/20

Document id	Document type	Type id	Document name	Date uploaded
E-46	Customised Estimate	6.2.2	MOD09 - 07 - Halfway Bush 11 kV Switchboard Replacement.xlsx	28/02/20
E-47	Customised Estimate	6.2.2	MOD09 - 08 - Dalefield Substation Rebuild.xlsx	28/02/20
E-48	Customised Estimate	6.2.2	MOD09 - 09 - Roxburgh 33 kV Outdoor Switchyard Renewal.xlsx	28/02/20
E-49	Customised Estimate	6.2.2	MOD09 - 10 - Smith Street 11 kV Switchboard Replacement.xlsx	28/02/20
E-50	Customised Estimate	6.2.2	MOD09 - 13 - Mosgiel Transformer Replacement and 33 kV Outdoor-Indoor Conversion.xlsx	28/02/20
E-51	Customised Estimate	6.2.2	MOD09 - 19 - South City 11 kV Switchboard Replacement.xlsx	28/02/20
E-52	Customised Estimate	6.2.2	MOD09 - 22 - Lauder Flat Transformer Replacement.xlsx	28/02/20
E-53	Customised Estimate	6.2.2	MOD09 - 26 - Clyde-Earnsclough Substation Rebuild.xlsx	28/02/20
E-54	Model	5.1.5	MOD82 - ICT Opex Forecast Model.xlsx	4/03/20
E-55	Model	5.1.11	MOD60 - ICT Capex Forecast Model.xlsx	18/03/20
E-56	Portfolio Overview Document (POD)	6.2.3	POD60 - ICT.pdf	18/03/20
E-58	Supporting document	9.1.2	Efficient Delivery of our CPP Work Programme - Explanatory Memo.pdf	4/03/20
E-71	Model	4.2.3	QS03 - Quality standards incentives.xlsx	6/03/20
E-72	Model	4.2.3	QS01 - Planned Reliability Forecast.xlsx	6/03/20
E-73	Model	4.2.3	QS02 - Unplanned Reliability Forecast.xlsx	6/03/20
E-74	Supporting document	8.1.3	QS00 - CPP Quality Standards Explanatory Memo.pdf	6/03/20
E-75	Supporting document	9.1.2	Aurora VoLL report FINAL.pdf	6/03/20

Document id	Document type	Type id	Document name	Date uploaded
E-76	Model	5.1.4	MOD73 - Vegetation Management Forecast Model.xlsx	6/03/20
E-77	Portfolio Overview Document (POD)	6.2.3	POD73 - Vegetation Management.pdf	6/03/20
E-81	Portfolio Overview Document (POD)	5.1.5	MOD81 - People Cost Forecast Model.xlsx	9/03/20
E-82	Portfolio Overview Document (POD)	5.1.5	MOD80 - SONS Forecast Model.xlsx	9/03/20
E-84	Supporting document	7.1.1	Technology and Digital Transformation Governance Group TOR.docx	18/03/20
E-85	Supporting document	9.1.2	Architecture Principles for Technology Architecture.docx	18/03/20
E-86	Supporting document	9.1.2	Communications Management Approach Template.docx	18/03/20
E-87	Supporting document	9.1.2	Change Control Approach Template.docx	18/03/20
E-88	Supporting document	7.1.1	Quality Management Approach Template.docx	18/03/20
E-89	Supporting document	9.1.2	Benefits Management Approach Template.docx	18/03/20
E-90	Supporting document	7.1.1	Risk Management Approach Template.docx	18/03/20
E-91	Supporting document	7.1.1	Project Close Report Template.docx	18/03/20
E-92	Supporting document	9.1.2	Business Case Template.docx	18/03/20
E-93	Supporting document	7.1.1	Project Plan Template.docx	18/03/20
E-94	Supporting document	9.1.2	End Stage Report Template.docx	18/03/20
E-95	Supporting document	7.1.1	Project Brief Template.docx	18/03/20
E-96	Supporting document	7.1.1	Stage Plan Template.docx	18/03/20
E-97	Supporting document	7.1.1	Project Initiation Template.docx	18/03/20
E-98	Supporting document	9.1.2	Highlight Report Template.docx	18/03/20
E-99	Supporting document	9.1.2	Exception Report Template.docx	18/03/20
IP-1235	Network standard- Fleet Management	3.2.12 /3.4.1	AE-FA17-F01 - Current Transformer Test Form.pdf	12/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IP-1236	Network standard- Corporate	3.2.14	AE-P253 Aurora Insurance Works Procedure.docx	12/12/2019
IP-1239	Network standard- Delivery	7.1.1	AE-DF03-F02 - Notice to Contractor.pdf	12/12/2019
IP-1244	Network standard- Operations	3.2.14	AE-OO05-G01 - Generator Set Fleet.pdf	12/12/2019
IP-1246	2018 - 2028 Asset Management Plan	2.1.1	Aurora-Energy-2018-AMP-UPDATED for 2019.pdf	12/12/2019
IP-1247	2018 - 2028 Asset Management Plan	2.1.1	Aurora-Energy-2019-AMP-Update.pdf	12/12/2019
IP-1248	Network standard- Commercial	3.2.13	AE-Policy-05 - Information Disclosure .docx	12/12/2019
IP-1249	Strategy - Easements	3.3.2	AE-CA04-W01 - Accidental Discovery of Archaeological Sites - Incidents.pdf	12/12/2019
IP-1250	Network standard- Safety	3.2.2	AE-HS05-S Incident Reporting and Investigation.docx	12/12/2019
IP-1251	Network standard- Safety	3.2.2	AE-HO07 - S - Contractor Health and Safety Requirements.docx	12/12/2019
IP-1252	Network standard- Safety	3.2.2	AE-HO09 - S - Selection and Use of Personal Protective Equipment.docx	12/12/2019
IP-1253	Network standard- Delivery	7.1.1	AE-DW06-G24 - Quality Assurance Guideline.docx	12/12/2019
IP-1254	Consultation - Materials Presented / Published	8.1.2	191112 CODC CPP Stakeholder Presentation - PRESENTED.pptx	12/12/2019
IP-1255	Consultation - Materials Presented / Published	8.1.2	191114 ERANZ Stakeholder CPP Presentation - FINAL (1).pptx	12/12/2019
IP-1256	Consultation - Materials Presented / Published	8.1.2	190924-26 CVP 5 September_Slides.pptx	12/12/2019
IP-1257	Consultation - Materials Presented / Published	8.1.2	190923 CAP 3_September_2019_Slides.pptx	12/12/2019
IP-1258	Consultation - Materials Presented / Published	8.1.2	191113 Commerce Commission Stakeholder CPP Presentation - PRESENTED.pptx	12/12/2019
IP-1259	Consultation - Strategy	8.1.1	190926 CPP Core Consultation Tactical Plan (v2).pdf	12/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IP-1260	Consultation - Materials Presented / Published	8.1.2	191022 CAP Interim Briefing October_Slides.pptx	12/12/2019
IP-1261	Consultation - Materials Presented / Published	8.1.2	191118 Newsletter Consultation Document now live – 19 Nov 2019.pdf	12/12/2019
IP-1262	Consultation - Materials Presented / Published	8.1.2	191118 QLDC CPP Stakeholder Presentation - PRESENTED.pptx	12/12/2019
IP-1263	Consultation - Materials Presented / Published	8.1.2	191120 MEUG Stakeholder CPP Presentation - FINAL (v2).pptx	12/12/2019
IP-1264	Consultation - Materials Presented / Published	8.1.2	191119 Retailer Stakeholder CPP Presentation - FINAL & PRESENTED.pptx	12/12/2019
IP-1265	Consultation - Materials Presented / Published	8.1.2	191119 DCC CPP Stakeholder Presentation - FINAL & PRESENTED.pptx	12/12/2019
IP-1266	Consultation - Materials Presented / Published	8.1.2	191125 CAP 4_November_2019_Slides.pdf	12/12/2019
IP-1267	Consultation - Materials Presented / Published	8.1.2	191126 CVP 4 Dunedin_November_2019_Slides.pdf	12/12/2019
IP-1268	Network standard- Delivery	7.1.1	AE-DW06-G25 - Change Management Guidelines.pdf	12/12/2019
IP-1268	Consultation - Materials Presented / Published	8.1.2	191127 CVP 4 Cromwell_November_2019_Slides.pdf	12/12/2019
IP-1269	Consultation - Materials Presented / Published	8.1.2	191128 CVP 4 Queenstown_November_2019_Slides.pdf	12/12/2019
IP-1270	Consultation - Materials Presented / Published	8.1.2	191209 Consultation docs for verifier_v1.docx	12/12/2019
IP-1271	Consultation - Materials Presented / Published	8.1.2	Aurora_Energy_Your_Network_Your_Say_web.pdf	12/12/2019
IP-1271	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Invitation_Age Concern.pdf	12/12/2019
IP-1272	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel - Media protocol_draft.pdf	12/12/2019
IP-1273	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel - Terms of Reference_June 2019.pdf	12/12/2019
IP-1274	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Invitation_Age Concern.pdf	12/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IP-1275	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Session 1 Summary_June 2019.pdf	12/12/2019
IP-1276	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Session 2 Summary_August 2019.pdf	12/12/2019
IP-1277	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Session 3 Summary_September 2019.pdf	12/12/2019
IP-1278	Consultation - Materials Presented / Published	8.1.2	Customer Advisory Panel Session 4 Summary_November 2019.pdf	12/12/2019
IP-1279	Consultation - Materials Presented / Published	8.1.2	EHQ Survey_Responses_Report_Tell us about your electricity use.pdf	12/12/2019
IP-1280	Consultation - Materials Presented / Published	8.1.2	Minutes for CAP Members_Interim Briefing_22 October 2019.pdf	12/12/2019
IP-1281	Consultation - Materials Presented / Published	8.1.2	Minutes for CAP Members Session 1_June 2019.pdf	12/12/2019
IP-1282	Consultation - Materials Presented / Published	8.1.2	Minutes for CAP Members_Session 2_August 2019.pdf	12/12/2019
IP-1283	Consultation - Materials Presented / Published	8.1.2	Minutes for CAP Members_Session 3_September 2019.pdf	12/12/2019
IP-1284	Consultation - Materials Presented / Published	8.1.2	Minutes for CAP Members_Session 4_November 2019.pdf	12/12/2019
IP-1285	Consultation - Materials Presented / Published	8.1.2	Newspaper Advert_191026 We want to hear from you.pdf	12/12/2019
IP-1286	Consultation - Materials Presented / Published	8.1.2	Newspaper Advert_191118 Lines charges to increase.pdf	12/12/2019
IP-1287	Consultation - Materials Presented / Published	8.1.2	social-ads-google-aw-overview-2019-12-09-12_30_10.pdf	12/12/2019
IP-1288	Consultation - Materials Presented / Published	8.1.2	social-business-facebook-Aurora-Energy-281027585640063-insights-2019-12-09-12_33_17.pdf	12/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IP-1289	Consultation - Materials Presented / Published	8.1.2	social-business-facebook-Aurora-Energy-281027585640063-ad-center-2019-12-09-12_28_03.pdf	12/12/2019
ID-1290	Consultation - Materials Presented / Published	8.1.2	social-linkedin-campaignmanager-account-508149473-campaigns-2019-12-09-12_32_02.pdf	12/12/2019
IP-1291	Consultation - Materials Presented / Published	8.1.2	social-studio-youtube-channel-UCPCZgZdRnkuT87v9Ic2qpyQ-videos-upload-2019-12-09-12_26_38.pdf	12/12/2019
IP-1292	Consultation - Survey findings / customer research	8.1.3	UMR 2019 businesses quant report _1 - final.pptx	12/12/2019
IP-1293	Consultation - Survey findings / customer research	8.1.3	UMR 2019 vulnerable quant report _1 - final.pptx	12/12/2019
IP-1294	Consultation - Survey findings / customer research	8.1.3	UMR 2019 households quant report _1 - final.pptx	12/12/2019
IP-1295	Consultation - Survey findings / customer research	8.1.3	UMR 2019_08 Aurora Energy CPP Toplines (Updated draft).docx	12/12/2019
IP-1296	Consultation - Survey findings / customer research	8.1.3	UMR Aurora Energy CPP questionnaire (June 2019) - Final.docx	12/12/2019
IP-1297	Consultation - Survey findings / customer research	8.1.3	UMR CAP 1 Qualitative - June 2019.pdf	12/12/2019
IP-1298	Consultation - Survey findings / customer research	8.1.3	UMR CAP 2 Qualitative - August 2019 - Final.pdf	12/12/2019
IP-1299	Consultation - Survey findings / customer research	8.1.3	UMR CAP 3 Qualitative - September 2019 - Final.pptx	12/12/2019
IP-1300	Consultation - Survey findings / customer research	8.1.3	UMR CVP 1 Qualitative - September 2018 - final.pptx	12/12/2019
IP-1301	Consultation - Survey findings / customer research	8.1.3	UMR CVP 2 Qualitative - November 2018 - final.pptx	12/12/2019
IP-1302	Consultation - Survey findings / customer research	8.1.3	UMR CVP 3 Qualitative - March 2019 - final.pptx	12/12/2019
IP-1303	Consultation - Survey findings / customer research	8.1.3	UMR CVP 4 Qualitative - August 2019.pdf	12/12/2019
IP-1304	Consultation - Survey findings / customer research	8.1.3	UMR CVP 5 Qualitative - September 2019 - final.pdf	12/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IP-1305	Consultation - Survey findings / customer research	8.1.3	UMR Qualitative Exploratory Research-Full Report-September 2019.pdf	12/12/2019
IP-1306	Consultation - Survey findings / customer research	8.1.3	UMR Qualitative Exploratory Research-Summary Report-October 2019.pdf	12/12/2019
IP-1307	Consultation - Materials Presented / Published	8.1.2	180827-29 CVP 1 August 2018_Slides.pptx	12/12/2019
IP-1308	Consultation - Strategy	8.1.1	180125 Draft CPP summary consultation plan_1.10.pdf	12/12/2019
IP-1309	Consultation - Materials Presented / Published	8.1.2	181126-28 CVP 2 November 2018_Slides.pptx	12/12/2019
IP-1310	Consultation - Materials Presented / Published	8.1.2	190312-14 CVP 3 March 2019_Slides.pptx	12/12/2019
IP-1311	Consultation - Materials Presented / Published	8.1.2	190315 2019 CPP summary consultation plan_2.3 for Board.pdf	12/12/2019
IP-1312	Consultation - Materials Presented / Published	8.1.2	190326 CPP Consultation Overview for Board.pdf	12/12/2019
IP-1313	Consultation - Strategy	8.1.1	190404 Aurora - High Level CPP Summary (Final) ComCom.pdf	12/12/2019
IP-1314	Consultation - Strategy	8.1.1	190430 Customer Advisory Panel plan.pdf	12/12/2019
IP-1315	Consultation - Materials Presented / Published	8.1.2	190619 CAP 1_June 2019 Slides.pptx	12/12/2019
IP-1316	Consultation - Materials Presented / Published	8.1.2	190813 CAP 2_August_2019_Slides.pptx	12/12/2019
IP-1317	Consultation - Materials Presented / Published	8.1.2	190813-15 CVP 4 August_Slides.pptx	12/12/2019
IP-1318	Consultation - Materials Presented / Published	8.1.2	190911 CPP CEO Newsletter Ver A (In region) - Sep 2019.pdf	12/12/2019
IP-1319	Consultation - Materials Presented / Published	8.1.2	190911 CPP CEO Newsletter Ver B (Out of region) - Sep 2019.pdf	12/12/2019
IP-1320	Consultation - Materials Presented / Published	8.1.2	190917 CPP Governance Committee Slides - 20 September 2019.pdf	12/12/2019
IP-1324	Network standard- Corporate	4.3.1	Aurora Energy - Organisational Structure - 27 Nov.pptx	12/12/2019

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IP-1325	Consultation - Materials Presented / Published	8.1.2	Consultation_summary_Feb_2020.pdf	11/03/2020
IP2-26	Models – Support Information	5.2.2	requirements.txt	31/01/2020
IP2-27	Models – Support Information	5.2.2	alf_v2.1.exe	31/01/2020
IP2-28	Models – Support Information	5.2.2	LICENSE.txt	31/01/2020
IP2-29	Models – Support Information	5.2.2	bat_helper.bat	31/01/2020
IP2-30	Models – Support Information	5.2.2	control.py	31/01/2020
IP2-31	Models – Support Information	5.2.2	environment.yml	31/01/2020
IP2-32	Models – Support Information	5.2.2	ALF_XL_Frontend_v1.12.xlsm	31/01/2020
IP2-33	Models – Support Information	5.2.2	IrrigationLoad2015Version4.csv	31/01/2020
IP2-34	Models – Support Information	5.2.2	ComCom Disclosure Load_DM.xlsx	31/01/2020
IP2-35	Models – Support Information	5.2.2	IrrigationLoadForecastVersion3DM.csv	31/01/2020
IP2-36	Models – Support Information	5.2.2	IrrigationLoadForecastVersion3.csv	31/01/2020
IP2-37	Models – Support Information	5.2.2	IrrigationLoadForecastVersion3.xlsx	31/01/2020
IP2-38	Models – Support Information	5.2.2	zonesub_eg_P10.csv	31/01/2020
IP2-39	Models – Support Information	5.2.2	zonesub_eg_mean.csv	31/01/2020
IP2-40	Models – Support Information	5.2.2	Solar Peak Contributions.xlsx	31/01/2020
IP2-41	Models – Support Information	5.2.2	New Entrant Embedded Generation.xlsx	31/01/2020
IP2-42	Models – Support Information	5.2.2	gxp_eg_mean.csv	31/01/2020
IP2-43	Models – Support Information	5.2.2	EG Peak Contributions.xlsx	31/01/2020
IP2-44	Models – Support Information	5.2.2	gxp_eg_P10.csv	31/01/2020
IP2-45	Models – Support Information	5.2.2	nzem_load_data.csv	31/01/2020
IP2-46	Models – Support Information	5.2.2	EY summary data_Infometrics.xlsx	31/01/2020
IP2-47	Models – Support Information	5.2.2	New step loads.xlsx	31/01/2020
IP2-48	Models – Support Information	5.2.2	SummaryPrudentOutput.csv	31/01/2020
IP2-49	Models – Support Information	5.2.2	SummaryExpectedOutput.csv	31/01/2020
IP2-50	Models – Support Information	5.2.2	ModelSpecs.pkl	31/01/2020
IP2-51	Models – Support Information	5.2.2	LoadForecastOutputFlat.csv	31/01/2020
IP2-52	Models – Support Information	5.2.2	input_archive.zip	31/01/2020
IP2-53	Models – Support Information	5.2.2	alf_log.html	31/01/2020
IP2-54	Models – Support Information	5.2.2	ALF_XL_Frontend_v1.12.xlsm	31/01/2020

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IP2-55	Models – Support Information	5.2.2	Wanaka.csv	31/01/2020
IP2-56	Models – Support Information	5.2.2	Roxburgh.csv	31/01/2020
IP2-57	Models – Support Information	5.2.2	read.py	31/01/2020
IP2-58	Models – Support Information	5.2.2	Queenstown.csv	31/01/2020
IP2-59	Models – Support Information	5.2.2	Queensberry.csv	31/01/2020
IP2-60	Models – Support Information	5.2.2	Outram.csv	31/01/2020
IP2-61	Models – Support Information	5.2.2	LindisCrossing.csv	31/01/2020
IP2-62	Models – Support Information	5.2.2	Omakau.csv	31/01/2020
IP2-63	Models – Support Information	5.2.2	LauderFlat.csv	31/01/2020
IP2-64	Models – Support Information	5.2.2	HHR Irrigation ICPs 20190515111359_EIEP3map. xlsx	31/01/2020
IP2-65	Models – Support Information	5.2.2	Fernhill.csv	31/01/2020
IP2-66	Models – Support Information	5.2.2	Frankton.csv	31/01/2020
IP2-67	Models – Support Information	5.2.2	Ettrick.csv	31/01/2020
IP2-68	Models – Support Information	5.2.2	EastTaieri.csv	31/01/2020
IP2-69	Models – Support Information	5.2.2	Cromwell.csv	31/01/2020
IP2-70	Models – Support Information	5.2.2	Dalefield.csv	31/01/2020
IP2-71	Models – Support Information	5.2.2	ClydeEarnscleugh.csv	31/01/2020
IP2-72	Models – Support Information	5.2.2	Cardrona.csv	31/01/2020
IP2-73	Models – Support Information	5.2.2	Camphill.csv	31/01/2020
IP2-74	Models – Support Information	5.2.2	Arrowtown.csv	31/01/2020
IP2-75	Models – Support Information	5.2.2	Alexandra.csv	31/01/2020
IP2-76	Models – Support Information	5.2.2	aggregated_TOU_irrigation_ data_v2.csv	31/01/2020
IP2-77	Models – Support Information	5.2.2	aggregated_TOU_EG_data.cs v	31/01/2020
IP2-78	Models – Support Information	5.2.2	Berwick.csv	31/01/2020
IP2-79	Models – Support Information	5.2.2	TABLECODE8081_FootnotesL egend_6da1d1c8-1275-4a10- 961c-4f71b1da48ab.csv	31/01/2020
IP2-80	Models – Support Information	5.2.2	TABLECODE8081_Data_6da1 d1c8-1275-4a10-961c- 4f71b1da48ab.csv	31/01/2020
IP2-81	Models – Support Information	5.2.2	Occupied private and non- private dwellings, 2001, 2006, and 2013 Censuses (RC, TA, AU).zip	31/01/2020

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IP2-82	Models – Support Information	5.2.2	Dwellings per capita - AU trends.csv	31/01/2020
IP2-83	Models – Support Information	5.2.2	TABLECODE7502_FootnotesLegend_d8d1827f-05fc-401f-91fc-c732372b795f.csv	31/01/2020
IP2-84	Models – Support Information	5.2.2	TABLECODE7502_Data_d8d1827f-05fc-401f-91fc-c732372b795f.csv	31/01/2020
IP2-85	Models – Support Information	5.2.2	Area unit Population projections for selected TAs - EY.xlsx	31/01/2020
IP2-86	Models – Support Information	5.2.2	Subnational population estimates (TA, AU), by age and sex, at 30 June 1996, 2001, 2006-18 (2017 boundaries).zip	31/01/2020
IP2-87	Models – Support Information	5.2.2	TABLECODE7507_FootnotesLegend_40b10203-7c6f-4f5b-baaf-5711b0d5fbde.csv	31/01/2020
IP2-88	Models – Support Information	5.2.2	TABLECODE7507_Data_40b10203-7c6f-4f5b-baaf-5711b0d5fbde.csv	31/01/2020
IP2-89	Models – Support Information	5.2.2	zonesubstation_clean_trading_period_load_v3.csv	31/01/2020
IP2-90	Models – Support Information	5.2.2	data_flag.py	31/01/2020
IP2-91	Models – Support Information	5.2.2	data_flag.cpython-37.pyc	31/01/2020
IP2-92	Models – Support Information	3.2.12	Demand Forecast Model_manual_v2.0.pdf	31/01/2020
IP2-93	Models – Templates	5.1.6	Economic Evaluation - Example Template.xlsx	31/01/2020
IP2-94	Consultation - Materials Presented / Published	8.1.3	Customer_Advisory_Panel_response_to_Aurora_Energy_CPP_consultation_document.pdf	31/01/2020
IP2-95	Models – Support Information	3.2.12	Aurora Natural Hazards Exposure Report - FINAL20200124.pdf	31/01/2020
IP2-96	Models – Templates	5.1.6	18 - LV Enclosures - example Repex model.xlsx	31/01/2020
IP2-97	Models – Templates	5.1.6	01 - Pole Survivor Curve Model.xlsx	31/01/2020
IP2-98	Models – Support Information	5.2.2	ZoneSubToTerritorialAuthority.xlsx	31/01/2020

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IP2-99	Models – Support Information	5.2.2	ZonesubToGXPmap.xlsx	31/01/2020
IP2-100	Models – Support Information	5.2.2	ZonesubMeterMap.xlsx	31/01/2020
IP2-101	Models – Support Information	5.2.2	New Zone Substations.xlsx	31/01/2020
IP2-102	Models – Support Information	5.2.2	HHR Irrigation ICPs 20190515111359_EIEP3map. xlsx	31/01/2020
IP2-103	Models – Support Information	5.2.2	AuroraZoneSub_Area17.xlsx	31/01/2020
IP2-104	Models – Support Information	5.2.2	__init__.py	31/01/2020
IP2-105	Models – Support Information	5.2.2	zonesub_data_cleaning.py	31/01/2020
IP2-106	Models – Support Information	5.2.2	run_alf.spec	31/01/2020
IP2-107	Models – Support Information	5.2.2	run_alf.py	31/01/2020
IP2-108	Models – Support Information	5.2.2	preprocessing.py	31/01/2020
IP2-109	Models – Support Information	5.2.2	model.py	31/01/2020
IP2-110	Models – Support Information	5.2.2	control.py	31/01/2020
IP2-111	Models – Support Information	5.2.2	load_inputs.py	31/01/2020
IP2-112	Models – Support Information	5.2.2	alf_log.py	31/01/2020
IP2-113	Models – Support Information	5.2.2	alf.spec	31/01/2020
IP2-114	Models – Support Information	5.2.2	top_level.txt	31/01/2020
IP2-115	Models – Support Information	5.2.2	SOURCES.txt	31/01/2020
IP2-116	Models – Support Information	5.2.2	requires.txt	31/01/2020
IP2-117	Models – Support Information	5.2.2	PKG-INFO	31/01/2020
IP2-118	Models – Support Information	5.2.2	not-zip-safe	31/01/2020
IP2-119	Models – Support Information	5.2.2	dependency_links.txt	31/01/2020
IP2-120	Models – Support Information	5.2.2	__init__.cpython-37.pyc	31/01/2020
IP2-121	Models – Support Information	5.2.2	zonesub_data_cleaning.cpyth hon-37.pyc	31/01/2020
IP2-122	Models – Support Information	5.2.2	run_alf.cpython-37.pyc	31/01/2020
IP2-123	Models – Support Information	5.2.2	preprocessing.cpython- 37.pyc	31/01/2020
IP2-124	Models – Support Information	5.2.2	model.cpython-37.pyc	31/01/2020
IP2-125	Models – Support Information	5.2.2	load_inputs.cpython-37.pyc	31/01/2020
IP2-126	Models – Support Information	5.2.2	control.cpython-37.pyc	31/01/2020
IP2-127	Models – Support Information	5.2.2	alf_log.cpython-37.pyc	31/01/2020
IP2-128	Models – Support Information	5.2.2	alf.cpython-37.pyc	31/01/2020
IP2-129	Models – Support Information	5.2.2	.Rhistory	31/01/2020
IP2-130	Models – Support Information	5.2.2	.Rhistory	31/01/2020

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IP-327	Network standard- Fleet Management	3.2.12	AE-F005 Mains Pillar Installation form.docx	12/12/2019
IP-333	Network standard - Commercial	3.3.6	AE-F016 Specification for Customer Supplied Trenching.pdf	12/12/2019
IP-375	Network standard - Commercial	3.3.6	AE-F052 Network Extension Contract Agreement.dotx	12/12/2019
IP-397	Network standard - Corporate	3.2.14	AE-F152 Aurora Monthly Insurance Schedule.docx	12/12/2019
IP-443	Network standard - Delivery	7.1.1	AE-F178 Variation Request.docx	12/12/2019
IP-535	Network standard - Operations	3.2.14	AE-P081 Network Outage Reports.docx	12/12/2019
IP-57	Network standard - Operations	3.2.14	AE-F061 HV Outage Report.docx	12/12/2019
IP-59	Network standard- Operations	3.2.14	AE-F062 Distribution Outage Report.docx	12/12/2019
IP-595	Network standard - Operations	3.2.14	AE-P211 Operation of HV Airbreak Switches.docx	12/12/2019
IP-627	Network standard - Commercial	3.3.7	AE-P232 Load Management.docx	12/12/2019
IPC-1000	Network standard - Operations	3.2.1	AE-OO05-F03 - Mobile Distribution Substation 6 Monthly Test and Inspection Form.pdf	29/11/2019
IPC-1001	Network standard - Operations	3.2.1	AE-OO05-F01 - Mobile Distribution Substation Installation and Liveness Check Sheet.pdf	29/11/2019
IPC-1002	Network standard - Fleet Management	3.3.8	AE-NT02-F01 - Tap Change Request Form.pdf	29/11/2019
IPC-1003	Network standard - Safety	3.2.1	AE-OO01-P01 - Reliving of HV Circuits.docx	29/11/2019
IPC-1004	Network standard - Fleet Management	3.3.11	AE-NR02-S - Underground Distribution Design and Construction.docx	29/11/2019
IPC-1005	Network standard - Fleet Management	3.3.3	AE-NR01-S - Overhead Distribution Design and Construction.docx	25/11/2019
IPC-1006	Network standard- Fleet Management	3.3.9	AE-NP02-F02 - Aprisa SR-SRplus Remote Radio Comms Survey Sheet.pdf	6/12/2019

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IPC-1007	Network standard - Fleet Management	3.2.12	AE-ND05-S - Network Equipment and Materials Assessment.docx	29/11/2019
IPC-1008	Network standard - Fleet Management	3.3.9	AE-NP02-F01 - Aprisa SR-SRplus Remote Radio Commissioning Sheet.docx	6/12/2019
IPC-1009	Network standard - Fleet Management	3.2.12	AE-ND04-F03 - New Equipment or Material Approval Request.pdf	29/11/2019
IPC-1010	Network standard - Fleet Management	3.2.12	AE-ND04-P01 - Safety in Design Process.docx	29/11/2019
IPC-1011	Network standard - Fleet Management	3.2.12	AE-ND04-F01 - New Equipment or Material Approval Evaluation Stage 1.pdf	29/11/2019
IPC-1012	Network standard - Fleet Management	3.3.3	AE-ND01-T01 - Pole Design.docx	22/11/2019
IPC-1013	Network standard - Safety	3.2.1	AE-HS08-T01 - Asset Types for Street Art.docx	29/11/2019
IPC-1014	Network standard - Safety	3.2.1	AE-HS08-S - Public Safety Management.docx	22/11/2019
IPC-1015	Network standard - Safety	3.2.11	AE-HS08-F02 - Street Art Access Permit.pdf	29/11/2019
IPC-1016	Network standard - Safety	3.2.11	AE-HS08-F01 - Street Art Health and Safety Checklist.pdf	29/11/2019
IPC-1017	Network standard - Safety	3.2.1	AE-HS05-S - Incident Reporting and Investigation.docx	22/11/2019
IPC-1018	Network standard - Safety	3.2.1	AE-HS05-F11 - Final Incident Alert.docx	22/11/2019
IPC-1019	Network standard - Safety	3.2.1	AE-HS05-F10 - Initial Incident Alert.docx	22/11/2019
IPC-1020	Network standard - Safety	3.2.1	AE-HS05-F06 - Five Why Incident Investigation Report.pdf	29/11/2019
IPC-1021	Network standard - Safety	3.2.1	AE-HS05-F03 - Witness Statement Form.pdf	29/11/2019
IPC-1022	Network standard - Safety	3.2.1	AE-HS05-F01 Incident Notification Form - Part A.pdf	29/11/2019
IPC-1023	Network standard - Corporate	2.1.3	AE-HS02-W01 - Risk Management Detailed Procedure.docx	22/11/2019

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IPC-1024	Network standard - Corporate	2.1.3	AE-HS02-S - Risk Control and Management.docx	29/11/2019
IPC-1025	Network standard - Safety	3.2.1	AE-HO07-S - Contractor Health and Safety Requirements.docx	22/11/2019
IPC-1026	Network standard - Corporate	2.1.3	AE-HS02-P02 - Risk Management Process Maps.docx	22/11/2019
IPC-1027	Network standard - Safety	3.2.1	AE-HO03-F01 - Safety Observation Form.pdf	29/11/2019
IPC-1028	Network standard- Operations	3.2.1	AE-HO02-F04 - Cable Mark Out Request.pdf	29/11/2019
IPC-1029	Network standard- Operations	3.2.1	AE-HO02-F03 - High Load Transport Request.pdf	29/11/2019
IPC-1030	Network standard- Operations	3.2.1	AE-HO02-F02 - Underground Cable Close Approach Request.pdf	29/11/2019
IPC-1031	Network standard- Operations	3.2.1	AE-HO02-F01 - Overhead Lines Close Approach Request.pdf	29/11/2019
IPC-1032	Network standard- Corporate	2.1.3	AE-HC01-S - Business Continuity - Readiness and Reduction.docx	29/11/2019
IPC-1033	Network standard- Fleet Management	3.2.12	AE-FR03-W01 - Conducting Inspections Using Electronic Data Capture.docx	29/11/2019
IPC-1034	Network standard- Fleet Management	3.2.4	AE-FR03-F06 - Recovered Equipment.pdf	29/11/2019
IPC-1035	Network standard- Operations	3.2.14	AE-FR03-G01 - As-Built Survey Guidelines - Electricity.docx	25/11/2019
IPC-1036	Network standard- Fleet Management	3.3.11	AE-FR03-F05 - Cable Installation Contractor Confirmation.pdf	29/11/2019
IPC-1037	Network standard- Fleet Management	3.2.12	AE-FR03-F04 - HV Link and Fuse Contractor Confirmation.pdf	6/12/2019
IPC-1038	Network standard- Fleet Management	3.4.1	AE-FR03-F03 - Earth Installation Test Report.pdf	29/11/2019
IPC-1039	Network standard- Fleet Management	3.3.3	AE-FR03-F02 - Pole-Line Installation Form.pdf	29/11/2019
IPC-1040	Network standard- Fleet Management	3.3.8	AE-FR03-F01 - Monthly Substation Inspection Form.pdf	29/11/2019

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IPC-1041	Network standard- Fleet Management	3.3.5	AE-FR01-F02 - Switchgear Installation.pdf	29/11/2019
IPC-1042	Network standard- Fleet Management	3.3.8	AE-FM16-F01 - Tap Changer Maintenance.docx	29/11/2019
IPC-1043	Network standard- Fleet Management	3.3.8	AE-FM08-P01 - DC System Maintenance.docx	29/11/2019
IPC-1044	Network standard- Fleet Management	3.4.1	AE-FM06-W01 - Hioki FT6380 Procedure.docx	29/11/2019
IPC-1045	Network standard- Fleet Management	3.4.1	AE-FM06-F01 - Hoiki Clamp On Earth Tester FT6380.pdf	29/11/2019
IPC-1046	Network standard- Fleet Management	3.3.5	AE-FM05-F02 - Oil Filled Switchgear (RMU) Maintenance.docx	29/11/2019
IPC-1047	Network standard- Fleet Management	3.3.11	AE-FM03-F05 - Gas Cable Alarm Test Form.pdf	29/11/2019
IPC-1048	Network standard- Fleet Management	3.3.11	AE-FM03-F04 - 33kV Cable Sheath Test Form.pdf	29/11/2019
IPC-1049	Network standard- Fleet Management	3.3.11	AE-FM03-F03 - Oil Cable Alarm Testing Form.pdf	29/11/2019
IPC-1050	Network standard- Fleet Management	3.4.1	AE-FA17-F06 - Voltage Transformer Test Form.pdf	29/11/2019
IPC-1051	Network standard- Fleet Management	3.3.5	AE-FA17-F01 - Current Transformer Test Form.pdf	29/11/2019
IPC-1052	Network standard- Fleet Management	3.3.8	AE-FA15-F02 - Outdoor Structure Maintenance Form.pdf	29/11/2019
IPC-1053	Network standard- Fleet Management	3.4.1	AE-FA14-W03 - Fall of Potential Testing.docx	29/11/2019
IPC-1054	Network standard- Fleet Management	3.4.1	AE-FA14-W02 - Earth Resistance Testing.docx	29/11/2019
IPC-1055	Network standard- Fleet Management	3.3.8	AE-FA14-F05 - Zone Substation Earth Grid Continuity Test.pdf	29/11/2019
IPC-1056	Network standard- Fleet Management	3.4.1	AE-FA14-W01 - Soil Resistivity Testing.docx	29/11/2019
IPC-1057	Network standard- Fleet Management	3.4.1	AE-FA15-F01 - Technician Check Sheet.pdf	29/11/2019
IPC-1058	Network standard- Fleet Management	3.4.1	AE-FA14-F03 - Fall of Potential Testing Form.pdf	29/11/2019
IPC-1059	Network standard- Fleet Management	3.4.1	AE-FA14-F02 - Earth Resistance Testing Form.pdf	29/11/2019
IPC-1060	Network standard- Fleet Management	3.3.8	AE-FA08-F02 - DC Systems Annual Test Form.docx	29/11/2019

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IPC-1061	Network standard- Fleet Management	3.3.8	AE-FA05-F10 - Indoor Switchboard Maintenance Check List.pdf	29/11/2019
IPC-1062	Network standard- Fleet Management	3.4.1	AE-FA14-F01 - Soil Resistivity Testing Form.pdf	29/11/2019
IPC-1063	Network standard- Fleet Management	3.3.8	AE-FA05-F09 - Recloser Annual Inspection.pdf	29/11/2019
IPC-1064	Network standard- Fleet Management	3.3.8	AE-FA05-F07 - Recloser - Outdoor Test Form.docx	29/11/2019
IPC-1065	Network standard- Fleet Management	3.3.8	AE-FA05-F06 - Oil Circuit Breaker - Outdoor Test Form.docx	29/11/2019
IPC-1066	Network standard- Fleet Management	3.3.8	AE-FA05-F05 - Oil Circuit Breaker - Indoor Test Form.docx	29/11/2019
IPC-1067	Network standard- Fleet Management	3.3.8	AE-FA05-F04 - SF6 Circuit Breaker - Outdoor Test Form.docx	29/11/2019
IPC-1068	Network standard- Fleet Management	3.3.8	AE-FA05-F08 - Zone Substation LV Bus Bar Test.docx	29/11/2019
IPC-1069	Network standard- Fleet Management	3.3.8	AE-FA05-F03 - SF6 Circuit Breaker - Indoor Test Form.docx	29/11/2019
IPC-1070	Network standard- Fleet Management	3.3.8	AE-FA05-F02 - Vacuum Circuit Breaker - Outdoor Test Form.docx	29/11/2019
IPC-1071	Network standard- Fleet Management	3.3.8	AE-FA05-F01 - Vacuum Circuit Breaker - Indoor Test Form.docx	27/11/2019
IPC-1072	Network standard- Fleet Management	3.4.1	AE-FA04-F03 - Voltage Regulator Annual Inspection.pdf	29/11/2019
IPC-1073	Network standard- Fleet Management	3.3.3	AE-FA01-F03 - Design - Structural Pole Assessment.pdf	29/11/2019
IPC-1074	Network standard- Customer and Engagement	3.2.14	AE-ER02-S - Media and External Communication.docx	29/11/2019
IPC-1075	Network standard- Fleet Management	3.4.1	AE-FA01-F01 - Compromised Pole Site Assessment.pdf	29/11/2019
IPC-1076	Network standard- Customer and Engagement	3.2.14	AE-EE04-F01 - Voltage Enquiry Form.pdf	29/11/2019

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IPC-1077	Network standard- Delivery	7.1.1	AE-DW06-G17 - Project Close Report Template.docx	29/11/2019
IPC-1078	Network standard- Delivery	7.1.1	AE-DW06-G18 - Lessons Report Template.docx	29/11/2019
IPC-1079	Network standard- Delivery	7.1.1	AE-DW06-G16 - Issue Report Template.docx	29/11/2019
IPC-1080	Network standard- Delivery	7.1.1	AE-DW06-G14 - Highlight Report Template.docx	29/11/2019
IPC-1081	Network standard- Delivery	7.1.1	AE-DW06-G15 - Exception Report Template.docx	29/11/2019
IPC-1082	Network standard- Delivery	7.1.1	AE-DW06-G13 - End Stage Report Template.docx	29/11/2019
IPC-1083	Network standard- Delivery	7.1.1	AE-DW06-G12 - Stage Plan Template.docx	29/11/2019
IPC-1084	Network standard- Delivery	7.1.1	AE-DW06-G11 - Project Plan Template.docx	29/11/2019
IPC-1085	Network standard- Delivery	7.1.1	AE-DW06-G10 - Benefits Management Approach Template.docx	29/11/2019
IPC-1086	Network standard- Delivery	7.1.1	AE-DW06-G09 - Communications Management Approach Template.docx	29/11/2019
IPC-1087	Network standard- Delivery	7.1.1	AE-DW06-G08 - Quality Management Approach Template.docx	29/11/2019
IPC-1088	Network standard- Delivery	7.1.1	AE-DW06-G07 - Risk Management Approach Template.docx	29/11/2019
IPC-1089	Network standard- Delivery	7.1.1	AE-DW06-G06 - Change Control Approach Template.docx	29/11/2019
IPC-1090	Network standard- Delivery	7.1.1	AE-DW06-G04 - Project Initiation Template.docx	29/11/2019
IPC-1091	Network standard- Delivery	7.1.1	AE-DW06-G03 - Project Brief Template.docx	29/11/2019
IPC-1092	Network standard- Delivery	7.1.1	AE-DW06-G02 - Business Case Template.docx	29/11/2019
IPC-1093	Network standard- Delivery	7.1.1	AE-DW05-F01 - Certificate of Practical Completion.pdf	29/11/2019
IPC-1094	Network standard- Delivery	7.1.1	AE-DW01-F02 - Job Completion Package - Distribution Assets.pdf	29/11/2019

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IPC-1095	Network standard- Fleet Management	3.2.12	AE-DW01-F01 - Minor Works Sketch.pdf	29/11/2019
IPC-1096	Network standard- Fleet Management	3.2.12	AE-DM03-F01 - Strategic Spare Procurement Request.pdf	29/11/2019
IPC-1097	Network standard- Delivery	7.1.1	AE-DF03-F01 - Notice to Contract.docx	29/11/2019
IPC-1098	Network standard- Commercial	3.2.14	AE-CP01-F01 - Loss Factors.docx	25/11/2019
IPC-1099	Network standard- Delivery	7.1.1	AE-DF01-S - Project Financial Management.docx	29/11/2019
IPC-1100	Network standard- Commercial	3.2.14	AE-CC01-F03 - Controlled Lighting Installation Record.pdf	29/11/2019
IPC-1101	Network standard- Commercial	3.2.14	AE-CB01-G02 - Capital Investment Schedules.docx	25/11/2019
IPC-1102	Network standard- Commercial	3.2.14	AE-CB01-G01 - Line Charge Schedules.docx	25/11/2019
IPC-1103	Network standard- Commercial	3.2.14	AE-CB01-F01 - Capital Funding Request.xlsm	25/11/2019
IPC-1104	Strategy - Easements	3.3.2	AE-CA05-S - Easements.docx	29/11/2019
IPC-1105	Strategy - Easements	3.3.2	AE-CA02-S - Access to Private Land.docx	29/11/2019
IPC-1106	Network standard- Commercial	3.2.14	AE-CA02-G01 - Biosecurity Information for Mycoplasma Bovis.docx	25/11/2019
IPC-1107	Strategy - Easements	3.3.2	AE-CA02-F04 - Easement Agreement - Adjoining Landowner.pdf	29/11/2019
IPC-1108	Strategy - Easements	3.3.2	AE-CA02-F03 - Easement Agreement - Landowner.pdf	29/11/2019
IPC-1109	Strategy - Easements	3.3.2	AE-CA02-F02 - Easement Agreement Landowner - Aurora Energy Driven Works.pdf	29/11/2019
IPC-1110	Strategy - Easements	3.3.2	AE-CA02-F01 - DoC Land Access Management Agreement.pdf	29/11/2019
IPC-1111	Network standard- Commercial	3.2.14	AE-AC01-F05 - CDS Access Application - Administrator.pdf	29/11/2019

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IPC-1112	Network standard- Commercial	3.2.14	AE-AC01-W03 - Controlled Document System - Read Only.docx	25/11/2019
IPC-1113	Network standard- Commercial	3.2.14	AE-AC01-G01 - Controlled Document System General Information Guide.docx	25/11/2019
IPC-1114	Network standard- Commercial	3.2.14	AE-AC01-W02 - Controlled Document System - Authors and Approvers.docx	25/11/2019
IPC-1115	Network standard- Commercial	3.2.14	AE-AC01-F04 - CDS Access Application - Individual User.pdf	29/11/2019
IPC-1116	Network standard- Commercial	3.2.14	AE-AC01-F03 - CDS Access Application Terms and Conditions.pdf	29/11/2019
IPC-1118	Policies and Planning Standards	3.1.1	Info Pack 1 - CDS Approved Policies and Planning Standards.xlsx	29/11/2019
IPC-1119	Policies and Planning Standards		Aurora List of Information to Deliver to farrierswier - Info Pack 1 - CDS Approved documents.xlsx	29/11/2019
IPC-1120	Policies and Planning Standards	1.1.1	Identified Programme Analysis for IV .xlsx	3/01/2020
IPC-1332	Network standard- Fleet Management	3.3.8	AE-FM15-W01 - Zone Substation Maintenance.pdf	24/12/2019
IPC-1333	Network standard- Delivery	7.1.1	AE-DW06-G23 - Risk Management - Project Guidelines.docx	24/12/2019
IPC-1334	Network standard- Corporate	3.2.14	AE-EE05-F01 - Expenditure Request.pdf	24/12/2019
IPC-1335	Network standard- Corporate	3.2.14	AE-SH09-S - Learning and Development.pdf	24/12/2019
IPC-1336	Network standard- Commercial	3.2.14	AE-CR02-S - Regulatory Disclosure.docx	24/12/2019
IPC-1337	Network standard- Commercial	3.2.14	AE-CR02-P31 - Annual Compliance Statement Check Sheet.docx	24/12/2019
IPC-1338	Network standard- Commercial	3.2.14	AE-CR02-P01 - Annual Information Disclosure - Schedule 1.docx	24/12/2019
IPC-1339	Network standard- Commercial	3.2.14	AE-CR02-P02 - Annual Information Disclosure - Schedule 2.docx	24/12/2019

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IPC-1340	Network standard- Commercial	3.2.14	AE-CR02-P03 - Annual Information Disclosure - Schedule 3.docx	24/12/2019
IPC-1341	Network standard- Commercial	3.2.14	AE-CR02-P04 - Annual Information Disclosure - Schedule 4.docx	24/12/2019
IPC-1342	Network standard- Commercial	3.2.14	AE-CR02-P05 - Annual Information Disclosure - Schedule 5a.docx	24/12/2019
IPC-1343	Network standard- Commercial	3.2.14	AE-CR02-P06 Annual Information Disclosure - Schedule 5b.docx	24/12/2019
IPC-1344	Network standard- Commercial	3.2.14	AE-CR02-P07 - Annual Information Disclosure - Schedule 5c.docx	24/12/2019
IPC-1345	Network standard- Commercial	3.2.14	AE-CR02-P08 - Annual Information Disclosure - Schedule 5d.docx	24/12/2019
IPC-1346	Network standard- Commercial	3.2.14	AE-CR02-P09 - Annual Information Disclosure - Schedule 5e.docx	24/12/2019
IPC-1347	Network standard- Commercial	3.2.14	AE-CR02-P10 - Annual Information Disclosure - Schedule 5f.docx	24/12/2019
IPC-1348	Network standard- Commercial	3.2.14	AE-CR02-P11 - Annual Information Disclosure - Schedule 5g.docx	24/12/2019
IPC-1349	Network standard- Commercial	3.2.14	AE-CR02-P12 - Annual Information Disclosure - Schedule 6a.docx	24/12/2019
IPC-1350	Network standard- Commercial	3.2.14	AE-CR02-P13 - Annual Information Disclosure - Schedule 6b.docx	24/12/2019
IPC-1351	Network standard- Commercial	3.2.14	AE-CR02-P14 - Annual Information Disclosure - Schedule 7.docx	24/12/2019
IPC-1352	Network standard- Commercial	3.2.14	AE-CR02-P15 - Annual Information Disclosure - Schedule 8.docx	24/12/2019
IPC-1354	Network standard- Commercial	3.2.14	AE-CR02-P21 - Annual Information Disclosure - Schedule 10.docx	24/12/2019
IPC-1355	Network standard- Commercial	3.2.14	AE-CR02-P12 - Information Disclosure - DPP Price Path.docx	24/12/2019

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IPC-1358	Network standard- Commercial	3.2.14	AE-CR02-P25 - Asset Management Plans Check Sheet.docx	24/12/2019
IPC-1359	Network standard- Commercial	3.2.14	AE-CR02-P28 - Information Disclosure Check Sheet.docx	24/12/2019
IPC-1360	Network standard- Commercial	3.2.14	AE-CR02-P27 - Disclosure of Prices Check Sheet.docx	24/12/2019
IPC-1361	Network standard- Commercial	3.2.14	AE-CR02-P30 - Pricing Methodology Check Sheet.docx	24/12/2019
IPC-1362	Network standard- Fleet Management	3.3.11	AE-FR01-F04 - HV Distribution Cable Test Report.pdf	10/3/2020
IPC-1363	Network standard- Corporate	3.2.14	AE-SH12-S - Protected Disclosures.docx	10/3/2020
IPC-1364	Network standard- Delivery	7.1.1	AE-DW06-G26 - Project Work Scope Template.docx	10/3/2020
IPC-1365	Network standard- Corporate	3.2.14	AE-SA07-F02 - Network Damage Incident Form.pdf	10/3/2020
IPC-1366	Network standard- Corporate	2.1.3	AE-HC01-G02 - Emergency Response Plan - All Staff Guide.pdf	10/3/2020
IPC-1367	Network standard- Safety	3.2.1	AE-HO09-S - Selection and Use of Personal Protective Equipment.docx	10/3/2020
IPC-1368	Network standard- Corporate	2.1.3	AE-OS04-P01 - Fire Risk Management Plan.pdf	10/3/2020
IPC-1369	Network standard- Fleet Management	3.3.11	AE-FR01-F03 - Transformer Installation.pdf	10/3/2020
IPC-1370	Network standard- Commercial	3.2.14	AE-FR01-F03 - Loss Factors.pdf	10/3/2020
IPC-1371	Network standard- Fleet Management	3.3.11	AE-FR01-F03 - Surge Arrester Installation.pdf	10/3/2020
IPC-1372	Network standard- Delivery	7.1.1	AE-SA19-S - Contract Management.pdf	10/3/2020
IPC-1373	Network standard- Corporate	2.1.3	AE-HC01-G01 - Organisational Business Continuity Plan.docx	10/3/2020
IPC-1374	Network standard- Corporate	2.1.3	AE-HC03-G01 - Emergency Response Plan - Level 3 Guide.pdf	10/3/2020
IPC-1375	Network standard- Corporate	3.2.14	AE-SH01-G01 - Company Dress Guidelines.docx	10/3/2020

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IPC-1376	Network standard- Fleet Management	3.3.3	AE-NT02-T06 - 300kVA Dunedin - TX Platform.pdf	10/3/2020
IPC-1377	Network standard- Fleet Management	3.3.3	AE-NT02-T03 - 300kVA PM TX Dunedin - Termination HV-In Line LV - rev C.pdf	10/3/2020
IPC-1378	Network standard- Fleet Management	3.3.3	AE-NT02-T02 - 300kVA PM TX Dunedin - In Line HV-In Line LV - rev C.pdf	10/3/2020
IPC-1379	Network standard- Fleet Management	3.3.3	AE-NT02-T05 - 300kVA PM TX Dunedin - Termination HV-Double Termination LV - rev C.pdf	10/3/2020
IPC-1380	Network standard- Fleet Management	3.3.3	AE-NT02-T04 - 300kVA PM TX Dunedin - In Line HV-Double Termination LV - rev C.pdf	10/3/2020
IPC-1381	Strategy -Secondary Systems	3.2.18	AE-NP01 - Sub-Transmission and Zone Substation Protection Standard.pdf	18/03/2020
IPC-1382	Policies and Planning Standards	3.1.1	Info Pack 1 - CDS Approved Policies and Planning Standards - Editable.xlsx	18/03/2020
IPC-953	Network standard- Corporate	3.2.14	AE-SH06-S - Leave Management.docx	29/11/2019
IPC-954	Network standard- Corporate	3.2.14	AE-SH06-F01 - Purchasing Annual Leave Request Form.pdf	29/11/2019
IPC-955	Network standard- Corporate	3.2.14	AE-SH05-F01 - Termination Checklist.pdf	29/11/2019
IPC-956	Network standard- Corporate	3.2.14	AE-SH04-S - Discrimination, Harassment and Bullying.docx	25/11/2019
IPC-957	Network standard- Corporate	3.2.14	AE-SG03-F03 - Driver Pledge.pdf	29/11/2019
IPC-958	Network standard- Corporate	3.2.14	AE-SG03-F01 - Vehicle Request Form.pdf	29/11/2019
IPC-959	Network standard- Corporate	3.2.14	AE-SG02-S - Travel and Accommodation.docx	29/11/2019
IPC-960	Network standard- Corporate	3.2.14	AE-SG01-S - Advertising_Sponsorship _ Donations.docx	29/11/2019
IPC-961	Network standard- Corporate	3.2.14	AE-SA17-S - Sensitive Expenditure.docx	25/11/2019
IPC-962	Network standard- Corporate	3.2.14	AE-SA16-S - Gifts Received or Given.docx	29/11/2019

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IPC-963	Network standard- Corporate	3.2.14	AE-SA15-S - Fringe Benefit Tax.docx	29/11/2019
IPC-964	Network standard- Contestable assets	3.2.6	AE-SA14-S - Procurement.docx	29/11/2019
IPC-965	Network standard- Corporate	3.2.14	AE-SA12-S - Reimbursement of Expenses Including Use of Private Vehicles.docx	25/11/2019
IPC-966	Network standard- Corporate	3.2.14	AE-SA11-S - Delegation of Financial Authority.docx	29/11/2019
IPC-967	Network standard- Corporate	3.2.14	AE-SA13-S - Entertainment Tax.docx	29/11/2019
IPC-968	Network standard- Corporate	3.2.14	AE-SA10-F03 - Request to Buy-Out Leave.pdf	29/11/2019
IPC-969	Network standard- Corporate	3.2.14	AE-SA10-F02 - Payroll Deduction Form.pdf	29/11/2019
IPC-970	Network standard- Corporate	3.2.14	AE-SA09-F02 - New Supplier.pdf	29/11/2019
IPC-971	Network standard- Corporate	3.2.14	AE-SA10-F01 - Bank Deposit Maintenance Form.pdf	29/11/2019
IPC-972	Network standard- Corporate	3.2.14	AE-SA09-F03 - Voucher - Prompt Payment.pdf	29/11/2019
IPC-973	Network standard- Corporate	3.2.14	AE-SA09-F01 - Refund of Expenses Claim Form.pdf	29/11/2019
IPC-974	Network standard- Corporate	3.2.14	AE-SA08-R01 - Preferred Supplier Register.pdf	29/11/2019
IPC-975	Network standard- Corporate	3.2.14	AE-SA08-S - Purchase To Pay.docx	25/11/2019
IPC-976	Network standard- Corporate	3.2.14	AE-SA07-F01 - Authority to Invoice (or Credit).pdf	29/11/2019
IPC-977	Network standard- Corporate	3.2.4	AE-SA05-F01 - Transfer or Disposal of Assets Form.pdf	6/12/2019
IPC-978	Network standard- Corporate	3.2.14	AE-SA08-F01 - Purchase Order Request.pdf	29/11/2019
IPC-979	Network standard- Customer and Engagement	3.2.13	AE-Policy-06 - Customer Charter.pdf	29/11/2019
IPC-980	Network standard- Fleet Management	3.2.12	AE-Policy-04 - Asset Management.pdf	6/12/2019
IPC-981	Network standard- Safety	3.2.1	AE-Policy-01 - Health and Safety.pdf	29/11/2019
IPC-982	Network standard- Safety	3.2.1	AE-OW04-S - Entry and Work Management.docx	22/11/2019

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IPC-983	Network standard- Commercial	3.2.14	AE-Policy-05 - Information Disclosure.docx	25/11/2019
IPC-984	Network standard- Safety	3.2.1	AE-OW04-G06 - Work Authority Form Completion Guide.docx	29/11/2019
IPC-985	Network standard- Safety	3.2.1	AE-OW04-G05 - Live Work Permit Form Completion Guide.docx	29/11/2019
IPC-986	Network standard- Safety	3.2.1	AE-OW04-G04 - Release Request Live Work Form Completion Guide.docx	22/11/2019
IPC-987	Network standard- Safety	3.2.1	AE-OW04-G03 - Test Permit Form Completion Guide.docx	29/11/2019
IPC-988	Network standard- Operations	3.2.1	AE-OW04-F06 - Work Authority.pdf	29/11/2019
IPC-989	Network standard- Safety	3.2.1	AE-OW04-G02 - Access Permit Form Completion Guide.docx	29/11/2019
IPC-990	Network standard- Safety	3.2.1	AE-OW04-G01 - Release Request Isolated Work Form Completion Guide.docx	29/11/2019
IPC-991	Network standard- Operations	3.2.1	AE-OW04-F05 - Live Work Permit.pdf	29/11/2019
IPC-992	Network standard- Operations	3.2.1	AE-OW04-F04 - Release Request Live Work.pdf	29/11/2019
IPC-993	Network standard- Operations	3.2.1	AE-OW04-F03 - Test Permit.pdf	29/11/2019
IPC-994	Network standard- Operations	3.2.1	AE-OW04-F02 - Access Permit.pdf	29/11/2019
IPC-995	Network standard- Operations	3.2.14	AE-OW01-R01 - Schedule of Competency Classes.xlsx	25/11/2019
IPC-996	Network standard- Operations	3.2.1	AE-OW04-F01 - Release Request Isolated Work.pdf	29/11/2019
IPC-997	Network standard- Operations	3.2.1	AE-OW01-F01 - Verification of Competency.pdf	29/11/2019
IPC-998	Network standard- Operations	3.2.1	AE-OO05-F04 - Mobile Distribution Substation Testing Log.pdf	29/11/2019
IPC-999	Network standard- Operations	3.2.1	AE-OO05-F02 - Mobile Distribution Substation Return From Service Check List.pdf	29/11/2019

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IPL-108	Network standard- Customer and Engagement	3.2.10	AE-F126 Form Letter - Complaint Acknowledgement.docx	4/12/2019
IPL-109	Network standard- Customer and Engagement	3.2.10	AE-F128 Form Letter - Complaint Delayed.docx	4/12/2019
IPL-110	Network standard- Customer and Engagement	3.2.10	AE-F127 Form Letter - Complaint Response.docx	4/12/2019
IPL-111	Network standard- Customer and Engagement	3.2.10	AE-F129 Information Leaflet - Complaint Handling.docx	4/12/2019
IPL-1117	Network standard- New connections	3.2.10	AE-S014-Network-Connection-Standard-Issued-9-May-2016.pdf	3/12/2019
IPL-1118	Network standard- New connections	3.2.10	Notes on Line Charges.pdf	3/12/2019
IPL-1119	Network standard- New connections	3.2.9 / 3.2.10	20120910-NS5-5-Rural-Harmonic-Standard.pdf	5/12/2019
IPL-1121	Network standard- Safety	3.2.1	Safety-Working-Guide-Final.pdf	4/12/2019
IPL-1122	Network standard- Commercial	3.2.14	QLDC Authority.pdf	3/12/2019
IPL-1124	Network standard- Fleet Management	3.3.11	C1208 Part B-Technical Specification -Smith Street 33 Cables Renewal_Rev. 2.docx	4/12/2019
IPL-1126	Network standard- Commercial	3.2.14	AE-F009 Aurora Capacity Change Request.pdf	4/12/2019
IPL-1127	Network standard- Commercial	3.2.10	AE-G002 Guide to SSDG.docx	4/12/2019
IPL-1128	Network standard- Commercial	3.3.6	AE-F008 Aurora Application.pdf	4/12/2019
IPL-1129	Network standard- Commercial	3.3.6	AE-F011 SSDG Connection Application.pdf	4/12/2019
IPL-1130	Network standard- Commercial	3.3.6	AE-F012 LSDG Connection Application.pdf	4/12/2019
IPL-1131	Network standard- Commercial	3.2.10	AE-F010-Network-Development-Application.pdf	4/12/2019
IPL-1132	Network standard- Commercial	3.3.6	AE-F013 LSDG Connection Application - Final.pdf	4/12/2019
IPL-1133	Network standard- Commercial	3.2.14	AE-F124 Notice of Confirmation of POS.docx	4/12/2019
IPL-1134	Network standard- Commercial	3.2.10	AE-G003 Guide to LSDG.docx	4/12/2019
IPL-1135	Appendices- Fleet Management	3.3.11	APPENDIX 2 - Aurora's Standard Trench Profile for 33 kV Two Circuits.pdf	13/12/2019

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IPL-1138	Appendices- Fleet Management	3.3.11	2-3279.pdf	16/12/2019
IPL-1139	Appendices- Fleet Management	3.3.11	20061.pdf	16/12/2019
IPL-1140	Appendices- Fleet Management	3.3.11	20167.pdf	16/12/2019
IPL-1141	Appendices- Fleet Management	3.3.11	9004-66 sht2.pdf	16/12/2019
IPL-1142	Appendices- Fleet Management	3.3.11	9004-66 sht1.pdf	16/12/2019
IPL-1143	Appendices- Fleet Management	3.3.11	9002-75.pdf	16/12/2019
IPL-1144	Appendices- Fleet Management	3.3.11	SMITH STREET SUBSTATION LAYOUT.pdf	16/12/2019
IPL-1145	Appendices- Fleet Management	3.3.11	9007-75.pdf	16/12/2019
IPL-1146	Appendices- Fleet Management	3.3.11	8969 HWB SS overview.pdf	13/12/2019
IPL-1147	Appendices- Fleet Management	3.3.11	8969 sheet 1.pdf	13/12/2019
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IPL-1149	Appendices- Fleet Management	3.3.11	8969 sheet 10.pdf	13/12/2019
IPL-1150	Appendices- Fleet Management	3.3.11	8969 sheet 11.pdf	13/12/2019
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IPL-1158	Appendices- Fleet Management	3.3.11	8969 sheet 2.pdf	13/12/2019

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IPL-1159	Appendices- Fleet Management	3.3.11	8969 sheet 18.pdf	13/12/2019
IPL-1160	Appendices- Fleet Management	3.3.11	8969 sheet 20.pdf	13/12/2019
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IPL-1163	Appendices- Fleet Management	3.3.11	8969 sheet 4.pdf	13/12/2019
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IPL-1169	Appendices- Fleet Management		HWB to SS ROUTE scans historical.zip	13/12/2019
IPL-1172	Appendices- Fleet Management	3.3.11	24-11-2017_3-51-31-570.pdf	16/12/2019
IPL-1173	Appendices- Fleet Management	3.3.11	Halfway Bush GXP Plan - Underground Cables.pdf	16/12/2019
IPL-1174	Appendices- Fleet Management	3.3.11	Halfway Bush Sample Location Plan.pdf	16/12/2019
IPL-1175	Appendices- Fleet Management	3.3.11	Single Line Diagram - Transpower Switchgear.pdf	16/12/2019
IPL-1176	Appendices- Fleet Management	3.3.11	TP54811_1_0 - 33kV cable layout and details.pdf	16/12/2019
IPL-1177	Appendices- Fleet Management	3.3.11	TOA Aurora Relay Building drawings.pdf	16/12/2019
IPL-1178	Appendices- Fleet Management	3.3.11	TP54811_2_0 - 33kV cable layout and details.pdf	16/12/2019
IPL-1179	Appendices- Fleet Management	3.3.11	TP55192 - 33kV Switchgear building typical cross section.pdf	16/12/2019
IPL-1180	Appendices- Fleet Management	3.3.11	TP55193 - 33kV Switchgear building RL98.89 plan & details.pdf	16/12/2019

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IPL-1181	Appendices- Fleet Management	3.3.11	TP54813 - 33kV switchgear building basement cable route schematic.pdf	16/12/2019
IPL-1182	Appendices- Fleet Management	3.3.11	TP55215 - 33kV switchgear building basement label details.pdf	16/12/2019
IPL-1183	Appendices- Fleet Management	3.3.11	TP55196 - 33kV Switchgear building block walls.pdf	16/12/2019
IPL-1184	Appendices- Fleet Management	3.3.11	TP55213_-_0_1237330[1].pdf	16/12/2019
IPL-1185	Appendices- Fleet Management	3.3.11	Transpower cable_layout.pdf	16/12/2019
IPL-1187	Appendices- Fleet Management		Typical Deliverables for a Cable Project.xlsx	13/12/2019
IPL-1189	Appendices- Fleet Management	3.3.11	Existing Single Line Diagram of Smith St Substation.pdf	16/12/2019
IPL-1191	Appendices- Fleet Management	3.3.11	Standardised Cross Section of 33 kV Sub Transmission Cable in Aurora Network.pdf	16/12/2019
IPL-1192	Appendices- Fleet Management	3.3.11	APPENDIX 9 -33 kV Sub Transmission Cable Specification Rev.2.pdf	16/12/2019
IPL-1194	Appendices- Fleet Management	3.3.11	Smith Street Sub - Termination Stand-2.pdf	16/12/2019
IPL-1195	Appendices- Fleet Management	3.3.11	Smith Street Sub - Termination Stands.pdf	16/12/2019
IPL-1197	Appendices- Fleet Management	3.3.11	CustomerTranspower Brochure and process chart draft (002).pdf	16/12/2019
IPL-1199	Appendices- Fleet Management	3.3.11	PDR3471-Replace Smith St 33kV Gas Cables Rev.00- For RFT.pdf	16/12/2019
IPL-1200	Network standard- Network evolution	3.2.11	Aurora Energy Network Evolution Roadmap-r11.pdf	5/02/2020
IPL-231	Network standard- Operations	3.2.14	AE-P229 Grid Exit Point Load Management.docx	4/12/2019
IPL-263	Network standard- Operations	3.2.14	AE-S031 Network Operations Standard.pdf	4/12/2019
IPL-335	Network standard- Commercial	3.2.14	AE-F014 Electrical Reticulation Contract Agreement - template.dotx	4/12/2019
IPL-377	Network standard- Customer and Engagement	3.2.10	AE-F046 Aurora Consent Letter.dotx	4/12/2019

Document id	Document type	Type id	Document name	Date uploaded
IPL-411	Network standard- New connections	3.2.10	AE-F155 Moving Works Contract Agreement.dotx	27/11/2019
IPL-501	Network standard- Customer and Engagement	3.2.10	AE-P019 Electricity and Land Complaints.docx	4/12/2019
IPL-53	Network standard- Customer and Engagement	3.2.10	AE-F055 Voltage Complaint Form.doc	4/12/2019
IPL-561	Network standard- Fleet Management		AE-P112 Distribution Transformer Assessment and Refurb.docx	22/11/2019
IPL-579	Network standard- Operations	3.2.14	AE-P130 Interruptions To Supply.docx	4/12/2019
IPL-753	Network standard- New connections	3.3.6	20090810-NS5-3-DG-Tech-Requirements.pdf	3/12/2019
IPL-754	Network standard- New connections	3.2.9 / 3.2.10	20120628-Interim-Policy-Statement-Harmonics.pdf	5/12/2019
IPL-756	Network standard- Network evolution	3.2.11	Aurora Energy Network Evolution Roadmap-r101 - SUPERSEDED.pdf	5/02/2020
IPL-757	Network standard- Network security	3.2.7	AE-S009-Security of Supply - Participant-Outage-Plan-2017.pdf	4/12/2019
IPL-758	Network standard- New connections	3.2.10	AE-S010-Capital-Contributions-v1.3.pdf	3/12/2019
IPL-759	Network standard- Commercial	3.2.14	AE-S015-Pricing-Methodology-2019.pdf	28/11/2019
IPL-760	Network standard- Commercial	3.2.14	201401-Aurora-New-Use-of-System-Agreement.pdf	4/12/2019
IPL-761	Network standard- Commercial	3.2.14	Material-Deviations-from-Model-UoSA.pdf	28/11/2019
IPL-770	Network standard- Commercial	3.2.14	Central Otago Authority.pdf	3/12/2019
IPL-771	Network standard- Commercial	3.2.14	Dunedin Authority 2015-1234.pdf	3/12/2019

Aurora Energy responded to many of our questions through presentations made during the March 2020 workshops. For the remaining questions, Aurora Energy provided separate responses and/or new material (such as revised models). In the material provided by Aurora Energy, it has included our question when responding to it.

Table I.2: Relied upon responses to questions provided by Aurora Energy via the SharePoint site

Document id	Document type	Type id	Document name	Date uploaded
V-1	Response to Query	9.1.2	Documentation related to RFI D219 and RFI 240 - Non-network opex - benchmarking.pdf	12/3/2020
V-2	Response to Query	9.1.2	RFI No D240 - Aurora Energy Information Request Response - People costs validation.docx	10/03/2020
V-3	Response to Query	9.1.2	RFI No. D219 - Aurora Energy Information Request Response - SONS expenditure validation.docx	09/03/2020
V-4	Response to Query	9.1.1	D014 - LV enclosures unknown age prorate calc.xlsx	12/3/2020
V-5	Response to Query	9.1.1	RFI No D014 - Aurora Energy Information Request Response - LV enclosures.docx	12/3/2020
V-6	Response to Query	6.2.4	RFI No D115 - Aurora Irrigation Electrical Load Projections- Aqualinc RD19010-1.pdf	12/3/2020
V-7	Response to Query	9.1.1	RFI No D115 - Information Request Response - Demand forecasts.docx	12/03/2020
V-8	Response to Query	9.1.1	RFI No. D112 - Aurora Energy Information Request Response - Reactive maintenance data.docx	12/3/2020
V-9	Response to Query	9.1.1	RFI No. D111 - Aurora Energy Information Request Response - Reactive maintenance delivery.docx	12/03/2020
V-10	Response to Query	9.1.1	RFI No D013 - Aurora Energy Information Request Response - LV enclosures outages.docx	09/03/2020
V-11	Response to Query	9.1.1	RFI No D059 - Aurora Energy Information Request Response - Preventative Maintenance.docx	09/03/2020
V-12	Response to Query	9.1.1	RFI No. D097 - Aurora Energy Information Request Response - Corrective maintenance data.docx	09/03/2020
V-14	Response to Query	9.1.1	Graduate Engineer Position Description May 2019.docx	13/03/2020
V-15	Response to Query	9.1.1	Operational System Support Position Description.docx	13/03/2020
V-16	Response to Query	9.1.2	Aurora Energy - Position Description - Health and Safety Coordinator.docx	13/03/2020
V-17	Response to Query	9.1.2	Secondary Systems Engineer PD.docx	13/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-18	Response to Query	9.1.2	Contractor Performance Manager Position Description.docx	13/03/2020
V-18	Response to Query	9.1.2	Programme Resource Planner Position Description April 2019.docx	13/03/2020
V-20	Response to Query	9.1.2	Administrator (CIW) PD.docx	13/03/2020
V-21	Response to Query	9.1.2	Strategy and Reliability Performance Manager PD.docx	13/03/2020
V-22	Response to Query	9.1.2	Reliability Specialist Position Description.docx	13/03/2020
V-23	Response to Query	9.1.2	Operational Performance Manager Position Description.pdf	13/03/2020
V-24	Response to Query	9.1.2	Programme Administrator Position Description.DOCX	13/03/2020
V-25	Response to Query	9.1.2	Asset Lifecycle Engineer PD.pdf	13/03/2020
V-26	Response to Query	9.1.2	Customer Initiated Works Manager - Position Description.pdf	13/03/2020
V-27	Response to Query	9.1.2	Junior Project Manager Position Description.docx	13/03/2020
V-28	Response to Query	9.1.2	Programme Coordinator Position Description.docx	13/03/2020
V-29	Response to Query	9.1.2	Health and Safety Advisor Position Description.docx	13/03/2020
V-30	Response to Query	9.1.2	Contracts Coordinator (CIW) Position Description.docx	13/03/2020
V-31	Response to Query	9.1.2	Network Planning Manager Position Description.pdf	13/03/2020
V-33	Response to Query	9.1.2	Organisational Development Advisor Position Description March 2019.docx	13/03/2020
V-34	Response to Query	9.1.2	Risk and Assurance Manager PD.docx	13/03/2020
V-35	Response to Query	9.1.2	Executive Assistant - Cromwell.docx	12/3/2020
V-36	Response to Query	9.1.2	Aurora Energy Position Description Digital Communications Specialist - (Fixed Term).docx	13/03/2020
V-37	Response to Query	9.1.2	Financial Controller - Position Description.docx	12/3/2020
V-38	Response to Query	9.1.2	Data & Information Manager Position Description.pdf	13/03/2020
V-39	Response to Query	9.1.2	GM Digital Transformation PD.pdf	13/03/2020
V-40	Response to Query	5.2.3	RFI D293 - Aurora Pricebook Review Final 21 Jan 2020.pdf	15/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-41	Response to Query	9.1.1	RFI No D293 - Aurora Energy Information Request Response - Deliverability unit rates.docx	15/03/2020
V-42	Response to Query	9.1.1	RFI No D260 - Vegetation Management Strategy v1.0.pdf	17/03/2020
V-43	Response to Query	9.1.1	RFI No D261 - Vegetation Management Standard v1.0.pdf	17/03/2020
V-44	Response to Query	9.1.2	RFI No D455 - Aurora ISSP Strategy v9.pdf	17/03/2020
V-46	Response to Query	9.1.2	RFI No D474 - Business Plan-Technology Dashboard.pdf	17/03/2020
V-47	Response to Query	9.1.2	RFI No. D215 - Aurora Energy Information Request Response - SONS drivers and benefits.docx	17/03/2020
V-48	Response to Query	9.1.1	RFI No D215 - Section 6.2 of 2019 Annual Compliance Statement.pdf	17/03/2020
V-49	Response to Query	9.1.1	RFI No D465 - Budget Details - Master_04 29.01.2020.xlsx	17/03/2020
V-50	Response to Query	9.1.2	RFI No D474 - Business Plan-PG16-Targets - as at 17 March 2020.pdf	17/03/2020
V-51	Response to Query	6.1.2	RFI No D474 - Business Plan-PG30-KPIs - as at 17 March 2020.pdf	17/03/2020
V-52	Response to Query	9.1.2	RFI No. D216 - Aurora Energy Information Request Response - SONS drivers and benefits.docx	09/03/2020
V-53	Response to Query	9.1.1	D216 - AMMAT response.pptx	17/03/2020
V-54	Response to Query	9.1.2	RFI No D197 - Aurora Energy Information Request Response - SONS base year.docx	17/03/2020
V-55	Response to Query	9.1.2	RFI No D212 - Aurora Energy Information Request Response - SONS forecast efficiency .docx	09/03/2020
V-56	Response to Query	9.1.2	RFI No D234 - Aurora Energy Information Request Response - People costs data.docx	10/03/2020
V-58	Response to Query	9.1.2	RFI No D242 - Aurora Energy Information Request Response - People costs drivers and benefits.docx	10/3/2020
V-59	Response to Query	9.1.2	RFI No D242 - ComplyWith_Legislation16_03_2020 3_40_32 p.m_.xlsx	17/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-60	Response to Query	9.1.2	RFI No D198 - Aurora Energy Information Request Response - SONS base year .docx	09/03/2020
V-61	Response to Query	9.1.2	RFI No D452 - Core ICT Systems.xlsx	18/03/2020
V-63	Response to Query	9.1.2	RFI No D472 - Aurora Energy Information Request Response - ICT data.docx	18/03/2020
V-65	Response to Query	9.1.2	200319 Deliverability PPT for Verifier workshop.pptx	19/03/2020
V-66	Response to Query	6.2.3	P01 - Intro and Context.pptx	20/03/2020
V-67	Response to Query	9.1.2	200317-ICT Capex and Opex for Verifier workshop.pptx	19/03/2020
V-68	Response to Query	6.2.3	P02 - Asset Management.pptx	20/03/2020
V-69	Response to Query	6.2.3	P04 - Cost estimation and escalation.pptx	20/03/2020
V-70	Response to Query	8.1.3	200320 Customer Engagement for Verifier Workshop.pptx	20/03/2020
V-74	Response to Query	9.1.1	D354 - Information Request Response - Outage Data.xlsx	22/03/2020
V-75	Response to Query	6.2.3	P12 - Renewals - Distribution & LV conductor.pptx	23/03/2020
V-76	Response to Query	9.1.2	RFI D449 - Aurora Energy - Current State Technology Review - Final.pdf	17/03/2020
V-77	Response to Query	6.2.4	RFI No W484 - 20200227Aurora Energy_Escalation Indices_Final Report_27 February 2020.pdf	28/2/2020
V-79	Response to Query	9.1.2	RFI No W484 - 20200227 Annual time series for Aurora with percentage changes.xlsx	28/2/2020
V-80	Response to Query	9.1.1	D166 and informs D175 - Reconciliation of overhead line replacements.xlsx	25/03/2020
V-81	Response to Query	6.2.3	P06 - Renewals - Poles and Crossarms.pptx	25/03/2020
V-82	Response to Query	6.2.3	P07 - Renewals - LV Enclosures.pptx	25/03/2020
V-83	Response to Query	9.1.1	P12 - Renewals - Distribution & LV conductor.pptx	25/03/2020
V-84	Response to Query	6.2.3	D012 - LV Enclosures Inspection Data.zip	25/03/2020
V-86	Response to Query	2.1.4	Audit Risk Terms of Reference 2019.docx	25/03/2020
V-87	Response to Query	2.1.4	Board Charter 2019.docx	25/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-88	Response to Query	2.1.4	CPP Committee Terms of Reference 2019.docx	25/03/2020
V-89	Response to Query	2.1.4	Governance Structure.pptx	25/03/2020
V-90	Response to Query	2.1.4	Health Safety - Terms of Reference 2019.docx	25/03/2020
V-91	Response to Query	2.1.4	Remuneration Terms of Reference 2019.docx	25/03/2020
V-92	Response to Query	6.2.3	P05 - Vegetation Management v0.8.pptx	26/03/2020
V-96	Response to Query	6.2.1	W482 - Andersons Bay Substation Rebuild.docx	26/03/2020
V-97	Response to Query	6.2.1	W482 - Queenstown 33 kV Outdoor Switchyard Renewal.docx	26/03/2020
V-98	Response to Query	6.2.1	W482 - Andersons Bay Concept Design Report - Edison Energy Ltd.pdf	26/03/2020
V-99	Response to Query	6.2.3	P11 - Renewals - Zone Subs & Protection.pptx	26/03/2020
V-100	Response to Query	6.2.1	W482 - Queenstown Concept Design Report - Mitton ElectroNet.pdf	26/03/2020
V-101	Response to Query	6.2.1	W482 - Smith Street 11 kV Switchboard Replacement.docx	26/03/2020
V-102	Response to Query	6.2.1	W482 - Smith Street Concept Design Report - Ergo Consulting.pdf	26/03/2020
V-105	Response to Query	6.4.2	MOD09a - Power Transformers risk model.xlsx	26/03/2020
V-106	Response to Query	6.4.2	MOD09b - Indoor Switchgear risk model.xlsx	26/03/2020
V-107	Response to Query	6.4.2	MOD09c - Outdoor Switchgear AHI model.xlsx	26/03/2020
V-108	Response to Query	9.1.1	RFI No D074 - CM Step Change - Possum Guard Quantity Estimate.xlsx	26/03/2020
V-109	Response to Query	5.1.1	W495 - IV Forecast tracker 26 Mar - excludes non-network opex.xlsx	26/03/2020
V-110	Response to Query	9.1.1	W477 - LV conductor age profile mods.xlsx	26/03/2020
V-111	Response to Query	6.2.4	W478 - Distribution Conductor age profile mods.xlsx	26/03/2020
V-112	Response to Query	6.2.3	P13 - Other Network Capex - Consumer Connection.pptx	26/03/2020
V-113	Response to Query	9.1.1	RFI No. D100 - Aurora Energy Information Request Response - Rreactive maintenance data.docx	27/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-114	Response to Query	9.1.1	RFI No. D106 - Aurora Energy Information Request Response - Reactive maintenance step changes.docx	09/03/2020
V-115	Response to Query	6.2.3	D166 and informs D175 - Reconciliation of overhead line replacements - updated.xlsx	27/03/2020
V-116	Response to Query	9.1.2	RFI No D200 - Aurora Energy Limited - 3-5 Year Insurance Forecast V2.pdf	27/03/2020
V-117	Response to Query	9.1.1	RFI Nos D218 D236 and D468 - Capitalisation of Expenditure Standard.docx	27/03/2020
V-118	Response to Query	6.2.3	RFI No D200 - Aurora Energy Limited - 3-5 Year Insurance Forecast V2.pdf	27/03/2020
V-119	Response to Query	6.2.3	RFI Nos D218 D236 and D468 - Capitalisation of Expenditure Standard.docx	27/03/2020
V-120	Response to Query	6.2.3	P17 - Non Network Opex - SONS and people costs (final) - Post Workshop.pptx	27/03/2020
V-121	Response to Query	5.1.1	W495 - IV Forecast tracker 27 Mar.xlsx	27/03/2020
V-122	Response to Query	5.2.3	Relates to multiple RFIs - 01 - Unit Rates Master File.xlsx	27/03/2020
V-123	Response to Query	5.2.3	Multiple RFIs - Jacobs Review Methodology.docx	27/03/2020
V-124	Response to Query	9.1.1	D032 - Preventive Maintenance Step Changes.xlsx	27/03/2020
V-125	Response to Query	9.1.1	D068 - Corrective Maintenance Step Changes.xlsx	27/03/2020
V-126	Response to Query	9.1.1	RFI Nos D028 D060 and D098 - Maintenance opex - benchmarking.pdf	28/03/2020
V-127	Response to Query	9.1.1	W483 - Historical Outage data of Wanaka Zone Substation.xlsx	28/03/2020
V-129	Response to Query	6.4.1	Python_Code_Planned.txt	27/03/2020
V-130	Response to Query	6.4.1	planned-SAIDI-SAIFI model v4.8.xlsx	27/03/2020
V-131	Response to Query	6.4.1	Modelling_Assumptions_Planned_v4.xlsx	27/03/2020
V-132	Response to Query	6.4.1	Planned Methodology Technical v1.0.docx	27/03/2020
V-133	Response to Query		Forecast tracker.xlsx	27/03/2020
V-134	Response to Query	8.1.1	P03 - Reliability and Service Levels planned .pptx	27/03/2020

Document id	Document type	Type id	Document name	Date uploaded
V-135	Response to Query	6.4.1	Concept Explanation of unplanned Reliability_Approach_v04.pptm	27/03/2020
V-136	Response to Query	6.4.1	Category mapping from expenditure forecast to reliability forecast 27MAR.xlsx	27/03/2020
V-137	Response to Query	6.2.3	P09 - Growth - Arrowtown.pptx	28/03/2020
V-138	Response to Query	6.2.3	P10 - Growth - Riverbank.pptx	28/03/2020
V-139	Response to Query	4.2.8	P08 - Demand Forecasting.pptx	28/03/2020
V-140	Response to Query	6.2.3	P18 - Network Maintenance (Opex).pptx	31/03/2020
V-141	Response to Query	9.1.1	RFI No W485 - 20200227 Annual time series for Aurora with percentage changes.xlsx	31/03/2020
V-142	Response to Query	6.2.4	RFI No W485 - Escalators extraction for Verifier 30 Mar.xlsx	31/03/2020
V-146	Response to Query	7.1.1	Determine Service Provider Workstream.pdf	13/03/2020
V-147	Response to Query	7.1.1	ROI for Provision of Field Services - FINAL.pdf	16/03/2020
V-148	Response to Query	7.1.1	ROI Field Services - Procurement Plan - SIGNED.pdf	16/03/2020
V-149	Response to Query	7.1.1	20170630 Interim Asset Services Agreement.pdf	16/03/2020
V-150	Response to Query	7.1.1	NZ1-16041006-Riverbank Zone Substation Project Close Out Review Report.pdf	15/03/2020
V-152	Response to Query		2.1 Aurora - Audit & Risk - Management Report (Feb 20) EXTRACT.docx	02/04/2020
V-153	Response to Query	2.1.4	2.2.13 Master Risk Register 28012020.xlsx	28/01/2020
V-155	Response to Query		RFI Nos W487 - W488 - W489.docx	02/04/2020
V-156	Response to Query	9.1.1	2.2.12 Monthly Risk Report February 2020.docx	02/04/2020
V-160	Response to Query	9.1.1	RFI D454 - Aurora Energy Asset Management Maturity Assessment.pdf	16/03/2020

Table I.3: Relied upon responses to our draft report by Aurora Energy via the SharePoint site

Document id	Document type	Type id	Document name	Date uploaded
PR-2	Post Draft Review Response	5.1.7	MOD09 - Zone Substation Coordination Model - Post IV review.xlsx	21/04/2020

Document id	Document type	Type id	Document name	Date uploaded
PR-3	Post Draft Review Response	9.1.1	Notes regarding Updated MOD09 - Zone Substations Coordination model.docx	21/04/2020
PR-5	Post Draft Review Response	6.1.2	MOD50 - Major Tourism Operator's Upgrade Customised Estimate.xlsx <sup>319</sup>	22/04/2020
PR-6	Post Draft Review Response	5.1.1	MOD50 - Consumer Connection Forecast Model - Post IV Review.xlsx	22/04/2020
PR-7	Post Draft Review Response	5.1.1	Note regarding MOD50 – Consumer Connection Forecast Model.docx	22/04/2020
PR-8	Post Draft Review Response	6.1.2	Arrowtown 33kV Ring Partial Prudent Forecast (RY20 to RY23).xlsx	22/04/2020
PR-10	Post Draft Review Response	5.1.7	MOD18 - LV Enclosures - Post IV Review.xlsx	23/04/2020
PR-11	Post Draft Review Response	5.2.3	LV enclosure unit rate explanation.xlsx	23/04/2020
PR-12	Post Draft Review Response	5.2.3	Crossarms unit rate explanation.xlsx	23/04/2020
PR-15	Post Draft Review Response	9.1.2	Attachment 5 - Non-network Opex - SONS and People Workshop Slides.pptx	23/04/2020
PR-16	Post Draft Review Response	9.1.2	Appendix 2 , 3, 4 and 5 - SONS People - App 2 to 5.xlsx	23/04/2020
PR-17	Post Draft Review Response	9.1.2	Attachment 6 - Aurora Energy Remuneration Standard.pdf	23/04/2020
PR-18	Post Draft Review Response	9.1.2	Attachment 7 - IV Remuneration Benchmarking Analysis – Strategic Pay (SP10) Analysis.xlsx	23/04/2020
PR-19	Post Draft Review Response	5.1.4	Attachment 8 - Network Evolution Model.xlsx	23/04/2020
PR-20	Post Draft Review Response	5.1.5	Attachment 2 - Revised PEOPLE BST Forecasting Model.xlsx	23/04/2020
PR-21	Post Draft Review Response	5.1.5	Attachment 1 - Revised SONS BST Forecasting Model.xlsx	23/04/2020
PR-22	Post Draft Review Response	9.1.2	01 - Memo to Verifier - 21 April 2020.pdf	23/04/2020
PR-23	Post Draft Review Response	5.1.5	Appendix 1 - Major SONS and People Step Changes and Guide to Supporting Information.pdf	23/04/2020
PR-24	Post Draft Review Response	9.1.2	Attachment 9 - Insurance Forecast spreadsheet.xlsx	23/04/2020

<sup>319</sup> The actual file name provided by Aurora Energy includes the name of the major tourism operator. We have removed this to preserve confidentiality.

Document id	Document type	Type id	Document name	Date uploaded
PR-25	Post Draft Review Response	9.1.2	Attachment 10 - Crombie Lockwood Report.pdf	23/04/2020
PR-26	Post Draft Review Response	9.1.2	Attachment 3 - Summary of Non-network forecast changes since March 19 workshop.xlsx	23/04/2020
PR-27	Post Draft Review Response	9.1.2	Attachment 4 - IV CPP Cost Forecasts.xlsx	23/04/2020
PR-28	Post Draft Review Response	9.1.1	Major Projects COVID impacts.pptx	26/04/2020
PR-29	Post Draft Review Response	5.1.12	Transpower Value of Lost Load (VoLL) Study.pdf	26/04/2020
PR-30	Post Draft Review Response	5.1.12	200426 VOLL note.docx	26/04/2020
PR-31	Post Draft Review Response	5.1.12	Aurora VoLL report FINAL.pdf	26/04/2020
PR-32	Post Draft Review Response	5.1.12	PWC_Estimating the Value of Lost Load.pdf	26/04/2020
PR-34	Post Draft Review Response	5.1.12	POD31 - Arrowtown 33kV Ring Upgrade - Post IV Review.docx	27/04/2020
PR-36	Post Draft Review Response	5.1.4	MOD72 - Reactive Maintenance Forecast Model - Post IV Review.xlsx	30/04/2020
PR-37	Post Draft Review Response	5.1.4	MOD71 - Corrective Maintenance Forecast Model - Post IV Review.xlsx	30/04/2020
PR-38	Post Draft Review Response	5.1.4	MOD71 - CM Step Changes - Post IV Review.xlsx	30/04/2020
PR-39	Post Draft Review Response	5.1.4	MOD70 - PM Step Changes - Post IV Review.xlsx	30/04/2020
PR-40	Post Draft Review Response	5.1.4	Maintenance Benchmarking Memo for IV - 29 April .docx	30/04/2020
PR-41	Post Draft Review Response	5.1.4	MOD70 - Preventive Maintenance Forecast Model - Post IV Review.xlsx	30/04/2020
PR-42	Post Draft Review Response	9.1.1	Draft Verification Report Responses - Maintenance.xlsx	30/04/2020
PR-44	Post Draft Review Response	9.1.1	01a - Forecast Efficiency Calculator.xlsx	30/04/2020
PR-45	Post Draft Review Response	5.1.1	01 - Forecast Tracker - Post IV Review.xlsx	30/04/2020
PR-46	Post Draft Review Response	9.1.1	Notes regarding the Forecast Tracker and Forecast Efficiency Calculator.docx	30/04/2020
PR-48	Post Draft Review Response	6.4.1	200503 Aurora network opex benchmarking.xlsx	14/05/2020

Document id	Document type	Type id	Document name	Date uploaded
PR-50	Post Draft Review Response	5.1.11	MOD60 - ICT Capex Forecast Model - Post IV Review.xlsx	04/05/2020
PR-51	Post Draft Review Response	5.1.5	MOD82 - ICT Opex Forecast Model - Post IV Review.xlsx	04/05/2020
PR-52	Post Draft Review Response	9.1.2	200502 ICT business benefits model.xlsx	04/05/2020
PR-53	Post Draft Review Response	9.1.2	200429 WSP Benchmarking analysis.DOCX	04/05/2020
PR-54	Post Draft Review Response	9.1.2	ICT_POD_v_7%20final.docx.pdf	04/05/2020
PR-56	Post Draft Review Response	9.1.2	Notes Regarding Revised ICT Forecast and Additional Supplementary Info.docx	04/05/2020
PR-57	Post Draft Review Response	6.4.1	Aurora-model-forecast-planned-SAIDI-SAIFI v5.01.xlsx	06/05/2020
PR-58	Post Draft Review Response	5.1.1	MOD50 - Consumer Connection Forecast Model - Post IV Review.xlsx	07/05/2020
PR-59	Post Draft Review Response	8.1.3	Memo Regarding CAP Feedback on Consultation.docx	10/05/2020
PR-60	Post Draft Review Response	6.2.4	Attachment 2 - Escalators extraction for Verifier 11 May.xlsx	11/05/2020
PR-61	Post Draft Review Response	9.1.1	Attachment 1 - Cost control - Governance Framework.docx	12/05/2020
PR-62	Post Draft Review Response	9.1.1	200512 Memo Responding to Follow-up Questions.docx	12/05/2020
PR-64	Post Draft Review Response	9.1.1	200512 Summary of Covid-19 moderations.pptx	12/05/2020
PR-66	Post Draft Review Response	6.4.1	equip_deterioration_v1.1.py.zip	14/05/2020
PR-67	Post Draft Review Response	6.4.1	equip_deterioration_v1.1.py	14/05/2020
PR-68	Post Draft Review Response	6.4.1	Aurora-model-forecast-unplanned-SAIDI-SAIFI v5.11.xlsx	14/05/2020
PR-69	Post Draft Review Response	6.4.1	200513 Unplanned forecast memo.docx	14/05/2020
PR-70	Post Draft Review Response	9.1.1	CPP Board Update - Forecasts Moderation and Lockdown - provided to IV.pdf	15/05/2020
PR-71	Post Draft Review Response	9.1.2	Memo Responding to Insurance Step Changes.docx	16/05/2020
PR-72	Post Draft Review Response	9.1.1	200516 Pole Reinforcement note.docx	18/05/2020

Document id	Document type	Type id	Document name	Date uploaded
PR-73	Post Draft Review Response	9.1.2	Capitalised Labour - Summary for IV.xlsx	20/05/2020
PR-74	Post Draft Review Response	9.1.1	200519 Vegetation Memo for IV.docx	20/05/2020
PR-76	Post Draft Review Response	6.4.1	planned_v9.5.zip	20/05/2020
PR-77	Post Draft Review Response	6.4.1	Aurora-model-forecast-planned-SAIDI-SAIFI v5.05.xlsx	20/05/2020
PR-78	Post Draft Review Response	6.4.1	Notes regarding Revised Planned Reliability model.docx	20/05/2020
PR-81	Post Draft Review Response	9.1.1	200520 Farrierswier and GHD - Draft Appendix F - Network risk - Aurora review.docx	20/05/2020
PR-82	Post Draft Review Response	9.1.1	Note regarding Aurora Feedback on Draft Appendix F.docx	20/05/2020
PR-83	Post Draft Review Response	3.3.11	20200203 Protections Systems Progress Report (FINAL).docx	20/05/2020
PR-84	Post Draft Review Response	8.1.2	200428 IV Reliability Question.docx	25/05/2020
PR-85	Post Draft Review Response	8.1.3	200505 IV Customer feedback on safety investment.docx	25/05/2020
PR-86	Post Draft Review Response	9.1.2	Memo Responding to Insurance Step Changes - 28 May 2020.docx	28/05/2020
PD-1	Penultimate Draft Feedback	6.4.1	200530 Chapter 3 feedback.docx	01/06/2020
PD-2	Penultimate Draft Feedback	6.4.1	200529 Review of Appendix E.docx	01/06/2020
PD-3	Penultimate Draft Feedback	6.4.1	Memo Responding to Reliability Penultimate Draft Feedback.docx	01/06/2020
PD-4	Penultimate Draft Feedback	9.1.1	200531 general feedback.docx	01/06/2020
PD-5	Penultimate Draft Feedback	9.1.1	Memo Providing General Feedback on Penultimate Draft.docx	01/06/2020
PD-6	Penultimate Draft Feedback	9.1.1	200602 final feedback.docx	02/06/2020
PD-7	Penultimate Draft Feedback	9.1.1	Consult Diagrams v06-09.png	02/06/2020
PD-8	Penultimate Draft Feedback	5.11.1	Demand Forecast Additional Information	03/06/2020
PD-9	Penultimate Draft Feedback	5.1.11	Arrowtown Ring Forecast	03/06/2020

Document id	Document type	Type id	Document name	Date uploaded
PD-10	Penultimate Draft Feedback	5.1.11	2. Output Visualisation Tool	03/06/2020
PD-11	Penultimate Draft Feedback	5.1.11	Memo Providing Additional Information Regarding Demand Forecast model	03/06/2020
PD-12	Penultimate Draft Feedback	6.4.1	Memo Regarding CPP Application Quality Standard.docx	04/06/2020

Table I.4: Other supporting information provided by Aurora Energy

Document name	Nature and source	Reason for relying on it	Date
Capital Contribution Policy	Available in website	To appreciate the application of two tier contribution arrangement.	21 August 2018
Newspaper article - Cadogan criticises Aurora over drop-in advertising	<a href="https://www.odt.co.nz/regions/central-otago/cadogan-criticises-aurora-over-drop-advertising">https://www.odt.co.nz/regions/central-otago/cadogan-criticises-aurora-over-drop-advertising</a>	Central Otago Mayor Tim Cadogan claimed the public session had been poorly advertised	20 December 2019

Table I.5: Information relied on that was not provided by Aurora Energy

Document name	Nature and source	Reason for relying on it	Date
2018 Asset Management Plan	Top Energy	Benchmarking LV enclosure renewal model assumptions and output metrics	27 March 2018
2018 Asset Management Plan	WEL Networks	Benchmarking LV enclosure renewal model assumptions and output metrics	29 March 2018
Electricity Asset Management Plan 2019	Powerco	Benchmarking LV enclosure and pole reinforcement renewal model assumptions and output metrics	2019
Access Arrangement Information for the AA4 period	Western Power	Benchmarking renewal model	2 October 2017

Document name	Nature and source	Reason for relying on it	Date
		assumptions and output metrics	
Powerline Asset Management Plan	SA Power Networks	Benchmarking renewal model assumptions and output metrics	January 2019
Independent Verification Report – Transpower’s RCP3 Expenditure Proposal (2020-25)	Synergies and GHD	Comparing asset expected life assumptions	12 October 2018
Regulatory Information Notices (RINs) response templates submitted by the Australian EDBs to the AER <sup>320</sup>	Various Australian EDBs	Benchmarking renewal model assumptions and output metrics	Response templates submitted to the AER at various dates AER website accessed at various times over April and May 2020
State of the infrastructure report 2017/18	Western Power	Benchmarking renewal model assumptions and output metrics	25 September 2018
Access Arrangement Information for the AA4 period	Western Power	Benchmarking assumptions and output metrics of asset management practices	2 October 2017
Powerline Asset Management Plan	SA Power Networks	Benchmarking assumptions and output metrics of asset management practices	January 2019
Independent Review of Electricity Networks	WSP	Refer the findings, especially with respect to network risk per asset fleet and how it has influenced the present AMP and the respective asset strategy	21 November 2018

<sup>320</sup> See: <https://www.aer.gov.au/taxonomy/term/1495>.

Document name	Nature and source	Reason for relying on it	Date
2019 and 2020 Asset Management Plans	Powerco	Historical record and forecast of wood pole reinforcement practice	March 2019, March 2020
2020-2030 Asset Management Plan	The Power Company	Historical record and forecast of wood pole reinforcement practice	March 2020
2020-2030 Asset Management Plan	Unison Network	Historical record and forecast of wood pole reinforcement practice	March 2020
Electricity distributors' information disclosure data 2013-2019.xlsm	The Commerce Commission	Latest reported asset statistics to the Commerce Commission	5 November 2019
EGX 429879 Replace 11kV wood pole (Ellipse system generated job estimate details)	Energex	Build-up of unit cost estimate for cross-arm replacement for overhead distribution network	8 April 2020
Estimate for 11kV crossarms installation job in Western Australia	GHD staff	Build-up of unit cost estimate for cross-arm replacement for overhead distribution network	9 April 2020