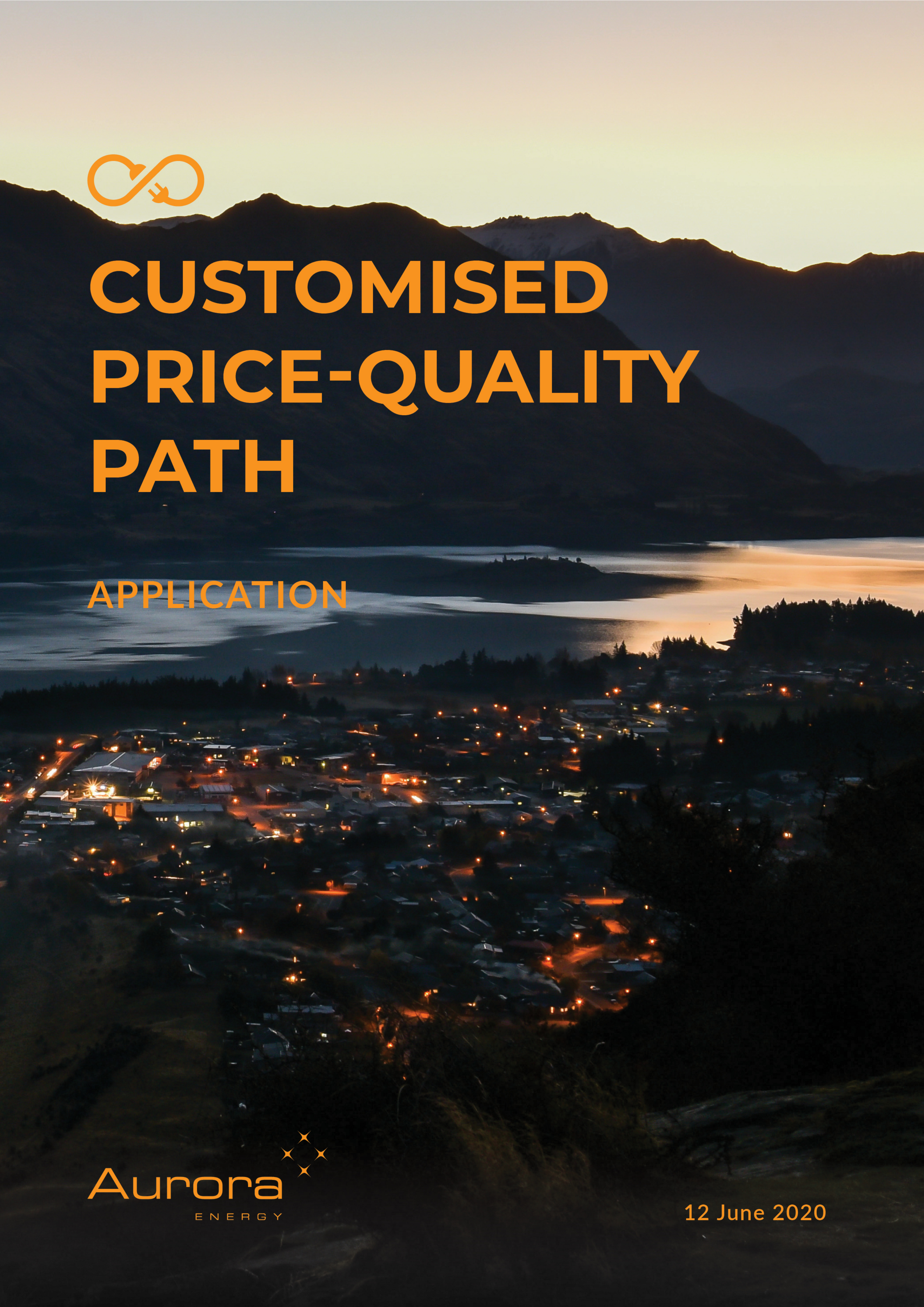

CUSTOMISED PRICE-QUALITY PATH

APPLICATION

Aurora ENERGY

12 June 2020

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1. Executive Summary

1.1. Introduction and the CPP Process

1.1.1. Introduction

1. This document is Aurora Energy's application for a customised price-quality path (CPP) setting out our proposal for future network investment and reliability standards. The purpose of this document is to:

   – describe our future expenditure plans and our proposed price-quality path;
   – explain why this proposal is in the long term interests of consumers; and
   – continue our engagement with customers and stakeholders on our final proposal.

2. The Commerce Commission (the Commission) will review our proposal and seek further customer and stakeholder feedback, before deciding on the revenue we can earn and quality standards that will apply for the CPP period.

3. We are asking the Commission to approve a three-year CPP period from 1 April 2021 to 31 March 2024 to ensure our proposed investments and quality standards are as well specified as possible.[1] We consider a three-year period is for the long-term benefit of consumers and is preferable to the usual five-year term for a CPP.

4. Like other electricity distribution businesses (EDBs), the accuracy and granularity of our forecasts become increasingly less certain over time. The combination of the step change in our investment requirements in the recent past and the developing state of our asset information and asset management maturity presents a challenge for forecasting expenditure (and reliability impact of that expenditure) over a five year regulatory period. Our forecasts therefore are materially more robust for the initial three years compared with years four and five.

5. Our three-year CPP focusses on getting the more certain priority work done while reducing the price risk to customers of committing too early to future expenditure. It further protects us and customers from having forecast expenditure in the later years of a five-year CPP being curtailed or misdirected due to current limitations in our forecasting capability. Such suboptimal investment could unnecessarily place customers at risk of deferred public safety risk remediation. A three-year period would give us and the Commission an opportunity to review and refine our longer term plans in light of better data and evidence, allowing us to better define a further five year price-quality path.

6. Reflecting the above, we intend to lodge a second CPP application for the subsequent five-year period beginning 1 April 2024. We would then be subject to CPP regulation and related regulatory oversight and performance monitoring for a total of eight years.

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1 While we are proposing a three year CPP (RY22 – 24), we are required to submit five years of information as part of our application. For consistency we refer to the *CPP Period* as the three-year period (RY22-24).

1.1.2. Who we are, What we do, Organisational History

7. Aurora Energy is the electricity network supplying homes, farms and businesses in Dunedin, Central Otago and Queenstown Lakes.

8. Under legislation, we are defined as a regulated EDB and a lifeline utility supplying an essential service. Aurora Energy is a wholly owned subsidiary of Dunedin City Holdings limited, which is owned by the Dunedin City Council. Our directors are appointed by our shareholder to govern and direct our activities.

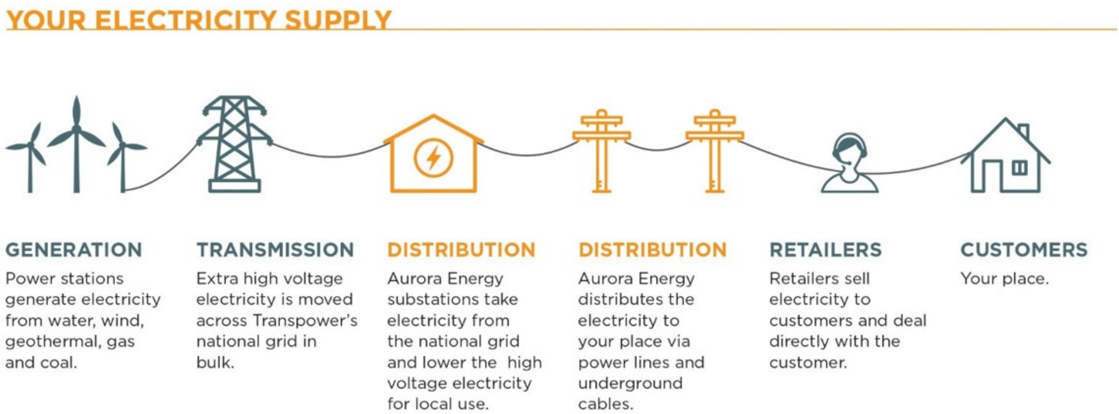
9. Our job is to deliver power from the national grid through our network of poles and wires to 91,000 customers across our network. We build, maintain and upgrade the poles, power lines, underground cables, substations and other equipment that deliver power.

10. The key services we provide the Otago community include:

   – Delivering electricity through poles and wires to your home or business
   – Providing an emergency response in the event of outages
   – Clearing trees away from network power lines for safety and reliability.

11. By delivering electricity to our communities when and where it is needed, safely, reliably and efficiently we support social and economic wellbeing of our communities and their economic growth.

12. We work, together with several other companies, to supply electricity, from generation and transmission to retail services.



13. Over the CPP Period, we plan to invest approximately $383 million (a reduction of approximately $20 million from our consultation proposal). Our ten-year network plans are set out in our latest 2020 Asset Management Plan (AMP).

1.1.3. New Structure and new Focus

14. In October 2016, significant network safety concerns were raised which culminated in an independent review by Deloitte, commissioned by our shareholders. In its report, Deloitte highlighted that we were operating with unsustainably low levels of expenditure, which led to unacceptable safety risks.

15. Since then we implemented the report's recommendations in full with a significant restructure of our organisation and a fundamental shift in our asset management approach. We separated from sibling company Delta in July 2017 and established Aurora Energy as a standalone network owner and asset manager with a new Board and management team.

16. The changes in approach to network investment and management have been comprehensive in the intervening years. We have:

- established a new Board, executive and team to operate as a standalone business
- commissioned an independent review (WSP review) of the state of the network under a tripartite agreement[2] with the Commission, establishing priority asset risks for remediation
- doubled annual investment on the network across a number of priority areas
- introduced a critical risk framework to prioritise remedial work and investment
- updated and published our ten-year investment plan (2018 AMP and a 2019 update)
- appointed three principal field service providers to carry out our expanded work programme
- replaced or reinforced more than 20% of poles on the network (~11,000 poles since 2017) and lifted pole inspection level to nearly 1,000 per month
- rebuilt our oldest network zone substation and invested in a new zone substation to meet growth
- implemented a new distribution management system and commissioned a second control room in Cromwell, enabling full network operation from either Dunedin or Cromwell
- established customer panels to better understand the needs of our customers
- been further scrutinised by an independent review (Sapere)[3] of our progress since separation from Delta, which concluded that we have taken all reasonable steps to mature our governance and asset management capability, and to build a sustainable business culture

17. In addition, our CPP expenditure proposal, setting out our investment plan and quality standards has been independently assessed by an independent verifier (see Section 1.3.2).The new approach and resulting changes constitute significant improvements in our forward planning and renewal programme. We have shifted our asset management approach towards good industry practice. Our CPP proposal and 2020 Asset Management Plan set out our improved long-term planning and better investment decision making.

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[2] WSP entered a tripartite agreement with us and the Commission to ensure an independent review and to assist the Commission on issues raised by the review. The Commission received periodic updates during the review.

[3] Available from Dunedin City Council website: https://www.dunedin.govt.nz/__data/assets/pdf_file/0003/757452/2019-Aurora-Review-19-February-2020.pdf

1.1.4. CPP Process Overview

18. The revenue that EDBs can recover when providing electricity distribution services, is regulated by the Commission. As a distribution company, our service makes up approximately 24% of a typical household power bill (averaged across the network). The Commission sets the total revenue an EDB can recover through line charges. We allocate our allowed revenue to prices in accordance with our published pricing methodology, which is regulated by the Electricity Authority.

19. Like most EDBs in New Zealand we operate under an interposed model where distribution costs are 'bundled' into electricity prices by retailers. Retailers' tariffs ultimately determine how actual distribution charges are passed through to end consumers. These tariffs are driven by other considerations including the retailer's competitive stance, prevailing energy prices, and transmission tariffs. Consumer bills may not be disaggregated sufficiently to identify the distribution portion of the bill.

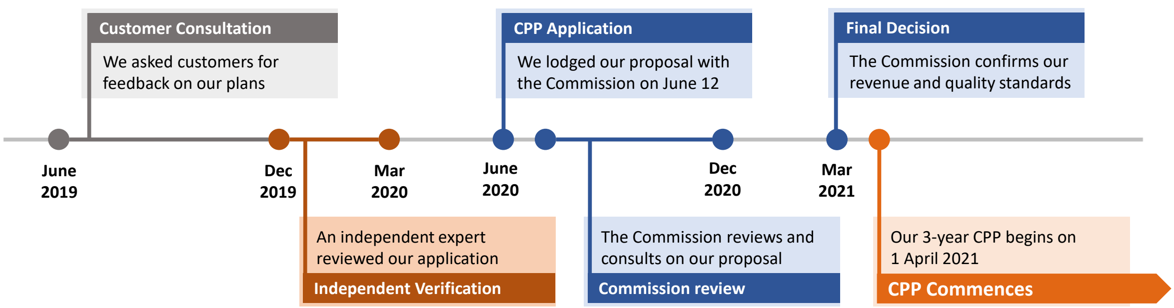
20. To promote the long term interests of electricity consumers, the Commission sets the maximum amount EDBs can recover though line charges and minimum reliability performance - known as the default price-quality path (DPP). Every five years, the Commission sets these revenue and reliability parameters for each regulated EDB in New Zealand (excluding EDBs under a CPP). The current five-year period commenced on 1 April 2020 and runs to 31 March 2025 (DPP3).

21. Following a proposal from an EDB, the Commission can determine a CPP to better suit the specific needs of the EDB and its customers. For example, and as applies in our case, a business may need to invest more in its network than provided for under a DPP.

22. Our CPP has undergone an in-depth audit and a technical and economic verification. The Commission will next take a close look at our proposal to ensure it is prudent and efficient and promotes the long term interests of customers before determining the new expenditure allowances and reliability levels.

23. Our application will now be reviewed by the Commission, including its own consumer consultation, before it issues a draft decision in late 2020, finalised in early 2021 and taking effect from 1 April 2021. The timeline for our CPP application is shown below.

Figure 1: Aurora Energy CPP application process and timeline



1.2. Why we are applying for a CPP

24. We are applying for a CPP because our ageing network requires more investment than provided for under the current DPP. Specifically, DPP3 does not deliver sufficient revenue to support the uplift in current and forecast expenditure needed to meet the expectations of our community and stakeholders. Nor does DPP3 set a level of unplanned outage performance (quality) that can be achieved with the corresponding revenue path.

25. Over several decades, our low level of investment kept prices low, and for many years (while the assets were in good health) delivered a high level of reliability performance. Likewise, historical investment levels were sufficient to gradually expand the network to keep step with demand growth and new connections.

26. Like other networks in New Zealand, much of our infrastructure was built in the 1950s and 1960s. As those assets age and progressively come due for replacement, our past level of investment was not enough to keep pace with a need for increased maintenance and renewal. As a result, the condition of our network assets has declined and reliability has deteriorated over recent years to a point where we breached our regulatory quality standards in 2012 and between 2016 and 2020 (inclusive).

27. The WSP review, conducted over six months, confirmed that a proportion of our network was in poor condition and would carry a higher public safety risk until the renewal backlog was addressed. The findings of this review reinforced the need for continued investment to address safety and reliability risks.

28. The priorities WSP identified in its risk assessment (particularly in the asset types of fault protection, poles and cross arms) were incorporated into our 2018 and subsequent Asset Management Plans, and these risks are being remedied in both our current work programme and the forecasts set out in our CPP application.

29. Since 2017 we have been carrying out a major capital works programme to address renewal backlogs. But with the large number of ageing assets on the network we are facing a multi-year period of investment catch-up and renewal work to avoid new safety risks emerging and to stabilise our reliability performance. Our CPP application is supported by a comprehensive 2020 Asset Management Plan.

30. If we invested at levels supported by DPP3, then safety across our networks would be compromised and reliability would continue to deteriorate. We would be unable to meet minimum safety compliance obligations and we would breach the new DPP3 reliability limits. This is an untenable situation for the current Board, our management team and staff.

31. To meet customer expectations for a safe and reliable service, and meet our minimum legal and safety obligations, we need to invest above the levels allowed under the DPP3. An increased programme of investment inevitably costs more. The much-needed increase in spend on network renewals, upgrades and maintenance has outstripped what we can recover under the current (DPP3) regulated revenue limits. This is why we are asking the Commission to reset the level of revenue we

can recover through our regulated lines charges. This will lead to prices that better match the costs of providing the distribution service.

32. Over the past three years we have significantly increased investment across the network, targeted at those assets which pose the greatest potential safety risk. This investment has drawn on shareholder funding to finance the shortfall. While it was prudent and necessary to increase network renewal ahead of cost recovery in the short term, this situation is not financially sustainable.

33. Our distribution prices (averaged across our three network regions) have historically been among the lowest in the country, but are no longer enough to support the level of investment needed to provide a safe and reliable service and to prepare the network for the future. Continued elevated levels of network investment will need to be funded through an increase in revenue, which would be passed onto electricity customers through increased line charges. We recognise that affordability is a concern for some in our community; however, we need to balance price impact against the risks that would be imposed on the public, and our contractors working on the network, if prudent investments were curtailed.

34. We operate under regulatory standards for network reliability; being the average annual duration and frequency of power outages. These limits are based on average historical reliability performance and are reset each regulatory period. Our DPP3 limits reflect an improving reliability trend from DPP1 to DPP2, resulting in quality standards that are among the most stringent in the country for comparable mixed urban/rural networks.

35. The DPP3 quality standards are split into planned and unplanned outages. These now include appropriate planned outage limits for an ageing network requiring outages to renew assets in a safe manner. However, the new unplanned outage limits are not representative of the current performance of the network or what is realistically achievable in the short-term. Furthermore, the level of investment and consequential level of customer prices that would be required to achieve the DPP3 level of unplanned outages is not consistent with what customers have told us during consultation. We are therefore applying for CPP quality standards that better reflect our circumstances and avoid further quality breaches.

36. Customers have told us they are generally unwilling to pay more for improved reliability. Our CPP plan is to invest to keep the network safe, as our primary objective. By improving overall asset condition, our safety-driven investments will arrest declining unplanned reliability performance.

1.2.1. The Counterfactual – Remaining on the DPP

37. To better understand the benefits of our CPP proposal we have developed a counterfactual view based on DPP3.

38. Under the DPP, and consistent with the relatively low-cost nature of the mechanism, the Commission determines expenditure allowances and quality standards based on its assessment of historic and high-level forecast information provided under information disclosure:

    38.1. Capex allowances are determined by taking AMP forecasts and subjecting them to a number of 'gateway' tests that generally involve comparison against past performance.

Ultimately, the allowance is constrained based on historical spend, which in our case had been too low .

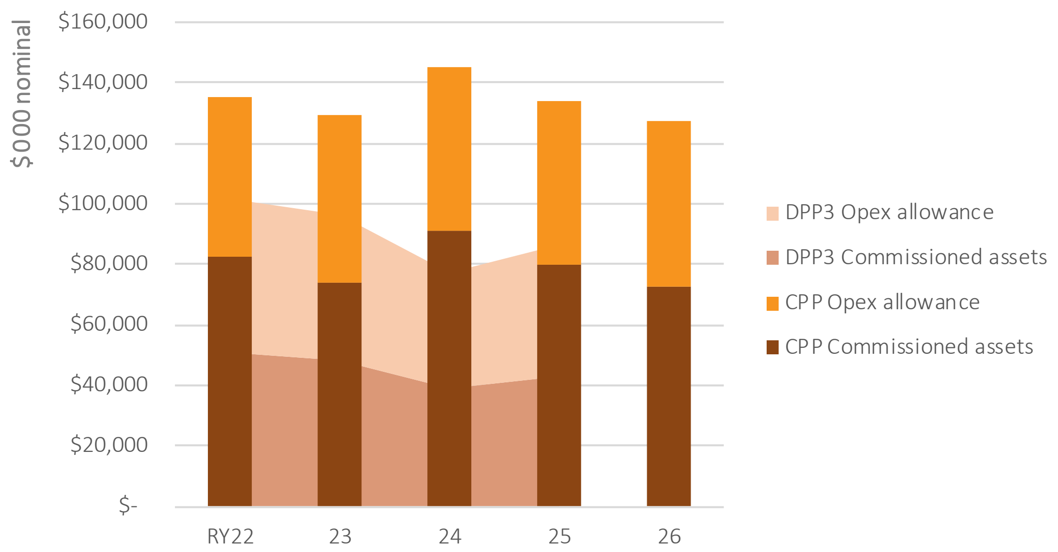
38.2. Opex allowances are determined using a base-step-trend approach, similar to the approach taken in developing our CPP Opex proposal, but:

- assessed at an aggregated level (Network / Non-network Opex); and
- step changes are assessed extrinsically, rather than specific to each business.

38.3. Quality standards are wholly determined with reference to historic performance, based on a ten-year average. For unplanned interruptions, a limit of 5% is placed on inter-period change; however, the key presumption is that past reliability is a good indicator of future performance and that performance has been relatively stable.

39. Figure 2 below shows the difference in the DPP expenditure allowances, and those under our CPP proposal. The DPP demonstrates a significant constraint on expenditure, when compared to our CPP proposal.

Figure 2: Comparison of expenditure allowances under DPP3 and our CPP proposal



40. If we were to remain on the DPP, we would be faced with two unworkable outcomes:

40.1. The first would be to curtail expenditure to the DPP allowances. The consequences of doing so would be that:

- The health of some assets would continue to deteriorate, posing an elevated level of safety risk to the public and contractors working on our network;
- The reliability of the network would continue to decline, resulting in elevated levels of consumer disruption;
- The risk profile of the business would increase to an extent that would not be acceptable to directors and management

40.2. If we continued to spend at the levels needed to improve asset health and stabilise reliability performance (consistent with our CPP proposal), the consequences of doing so would be that:

- Our revenues would be significantly out of alignment with our expenses, and a sustained period of below-normal/negative returns would be expected;
- We would need to continue to borrow at elevated levels or seek a capital injection to fund the needed investment (although investors are unlikely to invest in a low/negative return business);
- We would continue to incur significant penalties under the incremental rolling incentive, designed to incentivise expenditure efficiency, further exacerbating low returns;
- The long-term financial viability of the business would be compromised.

41. To understand the impact of continuing to overspend our regulatory allowances, we can look to the out-turn in the previous regulatory period. In the period 2016 to 2020, we have spent $207million more than our regulated allowances, predominantly aimed at prudently addressing our asset risks, as shown below.

Table 1: Actual spend versus regulated expenditure allowance - DPP2 (nominal, 000's)

	RY16	RY17	RY18	RY19	RY20
DPP2 Capex allowance[4]	$26,256	$16,971	$15,874	$17,294	$13,134
Actual spend[5]	$22,926	$26,639	$64,546	$66,047	$54,706
Cumulative Capex difference	-$3,330	$6,338	$55,010	$103,763	$145,335
DPP2 Opex allowance[6]	$22067	$22,846	$23,565	$24,305	$24,971
Actual spend	$25,173	$27,472	$36,298	$42,774	$48,968
Cumulative Opex difference	$3,106	$7,732	$20,465	$38,934	$62,931

42. These overspends have placed significant financial pressure on the business. In addition to the investment overspend the shareholder has foregone dividends, and will continue to do so for an extended period, even if this CPP Application is approved in full.

43. The option to remain on DPP3 is not realistic or sustainable. We have tested our CPP proposal with customers and have had the prudency and efficiency of our investments reviewed by the independent verifier. Our CPP proposal is the only way we can:

4 Commerce Commission. (2014). Electricity Distribution Business Price-Quality Regulation 1 April 2015 Reset – Model 4. Capex projections: Final Determination version. Version 2.0, 28 November 2014.

5 Actual expenditure (Capex and Opex) is from Schedule 7 of Aurora Energy's annual information disclosures. Note RY20 figures are based on current forecasts.

6 Commerce Commission. (2014). Electricity Distribution Business Price-Quality Regulation 1 April 2015 Reset – Model 3. Opex projections: Final Determination version. Version 2.0, 28 November 2014.

43.1. meet the long-term interests of consumers by providing safe network services at a reliability level that our customers have told us they are comfortable with, and

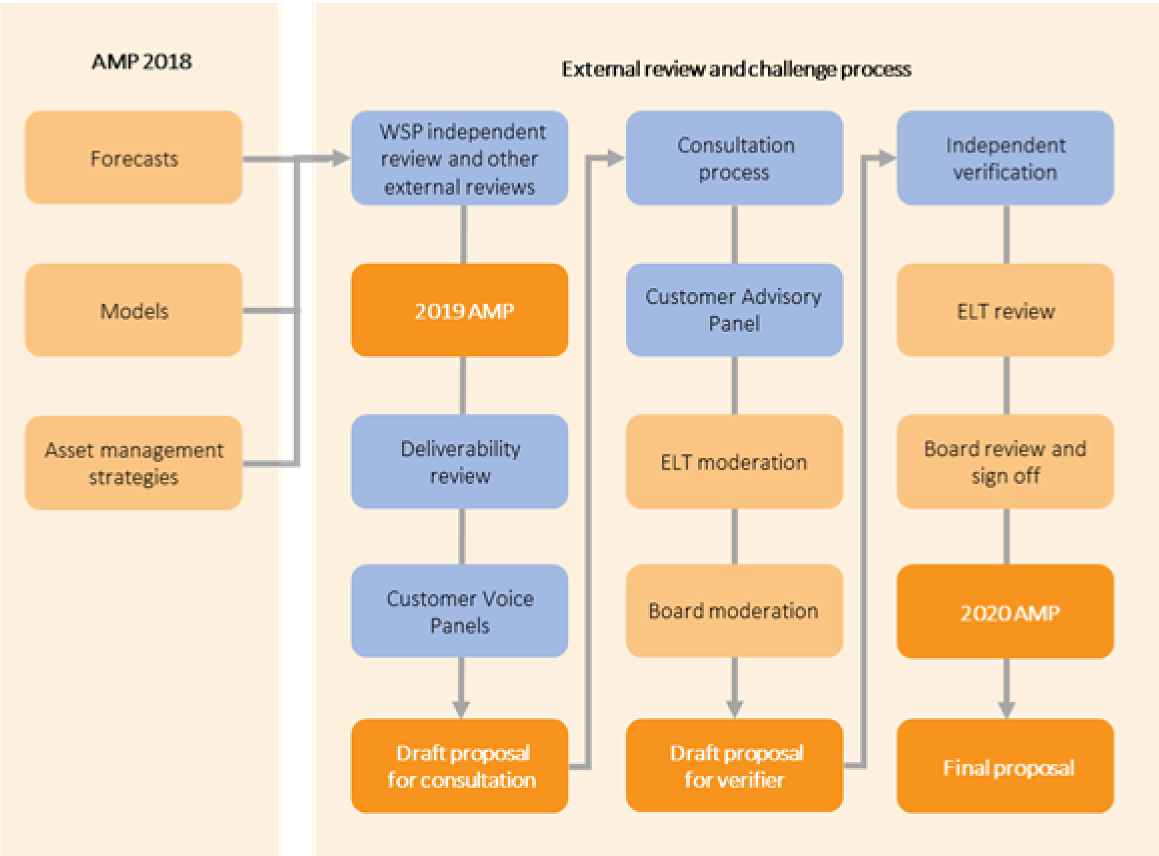
43.2. take a step toward ensuring the financial sustainability of the business.

1.2.2. How we Developed and Tested our Proposal

44. Few, if any, EDB expenditure plans have been subject to the level of independent scrutiny and analysis as the plans presented in this application. Not only has our new Board and management team rigorously tested and challenged the plan, many aspects of the business have been scrutinised over the last two years by the Commission and several independent experts and reviewers. This rigorous development and testing process provides confidence that our expenditure and quality plans for the CPP period are necessary, robust, efficient and strongly promote the interests of customers.

45. Figure 3, below, shows the review and challenge processes used in developing our proposal, from the 2018 AMP through to our draft proposal for consultation to the final proposal and 2020 AMP.

Figure 3: Challenge and external review process for Asset Management Plans and CPP proposal



46. The WSP review provided important input into the development of subsequent AMPs. From 2018 onwards, our AMPs and investments have been based on modern asset management principles

aligned to good electricity industry practice; an approach that is soundly based on risk and criticality assessments and managing the lifecycle of assets.

47. The Sapere review confirmed that our overall governance and approach to addressing the identified network issues is appropriate; further independent evidence that our approach is prudent.

48. In summary, our CPP plans have been tested through this combination of independent expert reviews, by our customer consultation, internal review and Board moderation processes, and peer review by the independent verifier. Throughout, we have amended our plans to take account of expert advice and customer feedback.

49. Customer views have been integral to shaping our proposals through customer panels and our consultation process. Our proposals have been reviewed and moderated throughout their development by our executive team and Board, which had ultimate review and approval. The independent verifier has performed an important expert role in reviewing our proposed plans and identifying areas where our expenditure proposal could be adjusted downward, and other areas where further analysis and evidence was required to justify and substantiate our proposals. The independent verifier worked on behalf of the Commission.

50. Other reports by external experts have contributed to developing and refining our draft proposal, risk assessments and forecasts. These have included external advice in the areas of unit rates, demand forecasting, network transformation, and information and communications technology (ICT) expenditure.

51. Our CPP plans are supported by our 2020 AMP, which has been developed through successive iterations by our engineering teams, who seek the most prudent and efficient response to identified needs, with advice from external experts where appropriate. Our 2020 AMP provides further analysis on our proposed expenditure for the CPP Period.

1.3. What Changed as a Result of Customer Feedback and Independent Review

1.3.1. Customer Consultation

52. Following customer feedback during consultation, and the views of the independent verifier, we made a series of moderations and changes to our draft CPP proposal before finalising it for submission. We also made some changes in response to the expected impacts of the Covid-19 pandemic on economic activity and regional electricity demand.

53. Customer consultation is a regulatory requirement of a CPP proposal, aiming to ensure that plans reflect customers' priorities and that our service reflects their preferences. We thank customers for their time and generosity in contributing their views on our future investment plans and preferences on what services they expect from us.

54. From previous energy sector consultations and our own experience and research, we understood that any CPP consultation would face challenges due to low public awareness and engagement. To

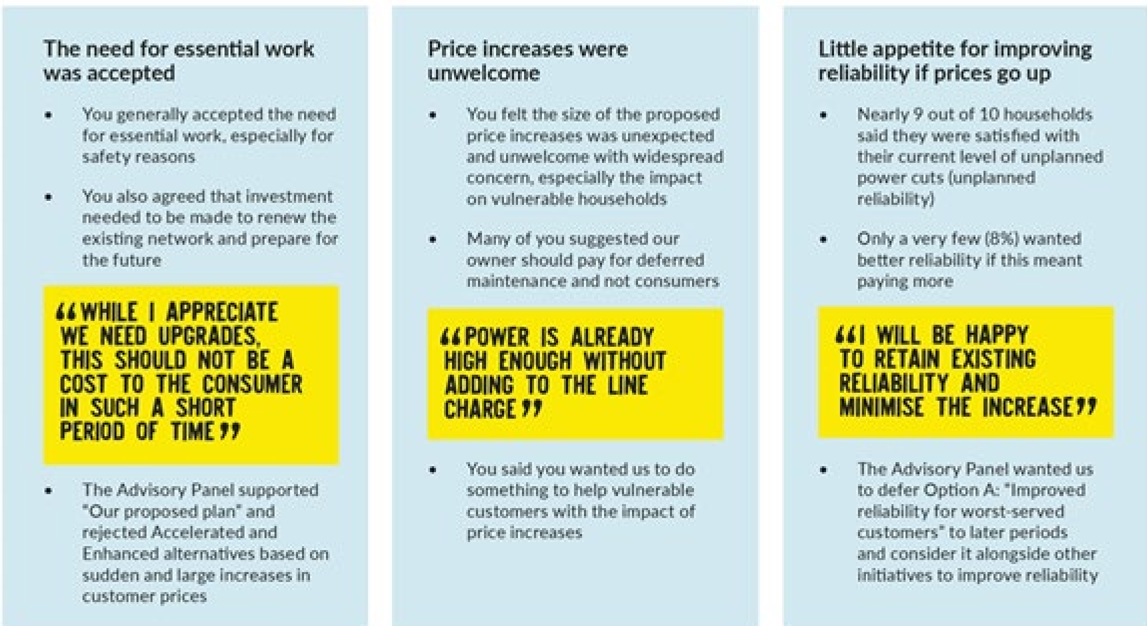
overcome these barriers to effective public participation, we took a phased approach to consultation, first building awareness before consulting on specific plans. We also established customer panels to connect us directly to customers and consumer experts and gave those participants the opportunity to influence our proposals through a fundamental base of knowledge.

Figure 4: Engagement process

55. Our consultation used deliberative engagement techniques, interactive online engagement and customer research. We provided multiple feedback channels to suit a range of customer preferences from customer panels, one-on-one meetings, stakeholder briefings, online engagement, video explainers and drop in sessions to customer surveys and in-depth research.

56. What we heard from customers was an understanding and desire for essential work to be done, but that the impact of the proposed pricing increase was a major concern for affordability, particularly for vulnerable customers. Most respondents were satisfied with the current level of reliability they experienced and there was little appetite for improving reliability if prices needed to increase to deliver this. Some aspects of customer service were expected and valued highly, namely communication about planned and unexpected power outages and the new connections process.

Figure 5: Key themes in response to our consultation document



1.3.2. Independent Verification of our CPP Proposal

57. An important aspect of the Commission’s CPP framework is the use of pre-submission verification by an independent verifier. At a high level, the verification process is intended to improve the overall

quality of CPP proposals and to guide the Commission's decision making by testing, in advance of submission, the often very complex engineering and planning assumptions underpinning forecast expenditure and intended quality standards.

58. Following a tender process and Commission approval, Farrierswier was appointed as the independent verifier, supported by GHD. Both are expert infrastructure advisory firms with experience in assessing regulatory proposals in New Zealand, and Australia.

59. The process of independent verification began in July 2019 and involved multiple site visits, meetings and workshops, plus a comprehensive exchange of information and evidence for the independent verifier's review. We provided more than 800 documents and spreadsheets (including detailed information on our investment proposal, proposed quality standards and how we operate our business), and responded to over 450 questions from the independent verifier on that information.

1.3.3. Changes as a Result of Customer Feedback and the Independent Verifier's Report

60. To address customer feedback and the views of the independent verifier, we made a series of moderations to our draft CPP proposal before finalising it for submission. In addition, we made expenditure reductions in response to the expected impacts of the Covid-19 pandemic on economic activity and regional electricity demand.

Table 2: Adjustments to our CPP proposal following consultation and the draft independent verifier's report

Customers told us….	In response, we have….
Increased investment is supported but affordability is a concern	Adopted 'Our proposed plan' rather than the 'Accelerated' or 'Enhanced' alternatives. This position is consistent with the feedback received that essential work is supported, but affordability is a significant concern.
Existing levels of reliability are acceptable	Targeted our investment plans to improve network safety and asset health (noting there will be consequential improvements in unplanned reliability).
The magnitude of the price increase raises concerns	Excluded any options that would have cost more (the 'Accelerated' or 'Enhanced' alternatives and additional service options) In addition, we reduced our proposed expenditure by approximately $20 million where this could be achieved without compromising safety or increasing future expenditure requirements. Specific initiatives are also proposed to assist customers to manage their electricity costs and address hardship issues.
Asset degradation should be avoided in future	Committed to improve our approach to asset management, which should ensure that the historical degradation of assets is not repeated in future.
Regional price differences raised concerns	Accepted that our pricing regions and cost allocations should be reviewed, and we will explain to consumers how prices

Customers told us....	In response, we have....
	are derived and the relative differences are fair and equitable.
Some customer services are expected as fundamental, but affordability is a primary concern	Excluded the 'Improved customer service' option, but retained investment in priority customer service initiatives and ongoing improvement during the three-year CPP period. Priorities identified by customers were improved outage information (e.g. real time updates for unplanned outages) and the new connections process.
Readiness for a low carbon future is valued by some customers, but affordability is a primary concern	Excluded the 'Improved future technology readiness' option, but retained sufficient investment during the three-year CPP period to remain prepared for technology change. Developed a *Network Evolution Plan* to support the network's transition to a low-carbon future and the uptake of distributed energy resources. Adopted a non-network solution for forecast network constraints in the Upper Clutha area at a lower lifetime cost. Under the solution, a contracted partner will provide Distributed Energy Resources (DERs) through the installation of solar panels and battery storage in customers' homes or small businesses.
Smoothed price increases are preferred, so that the impact on customers is managed	Opted for a smoothed pricing transition to manage the price impact on customers.

61. As discussed in paragraph 19, we have limited scope to influence final customer prices. Our revenues are set by the Commission and we must also adhere to the Electricity Authority's pricing principles that require pricing to reflect the costs of providing the service and to be allocated fairly across customers and regions.

62. However, in order to mitigate the impact of price increases, we have begun several initiatives, including continuing to lobby central government for quality breach fines to be reinvested in our community to benefit consumers, and advocating for a regional energy efficiency fund for vulnerable households in collaboration with local Councils.

1.3.4. How Independent Verification Shaped our Draft CPP Proposal

63. Following a challenge by the independent verifier, and consistent with the above views expressed by customers, we made the following further adjustments to our expenditure plans:

- we applied a series of efficiency adjustments to our spend plans. These are based on a range of expected efficiency sources. Over time these will lead to material reductions in costs (approximately $5 million over five years).
- we have deferred several non-critical renewal and growth projects, particularly those with a reliability driver, to later in the CPP period

- we have reduced future staffing costs to reflect likely productivity gains
- we have made a series of reductions in reactive and corrective maintenance to reflect potential improvements in overall asset condition and health.

1.3.5. The impact of Covid-19 pandemic

64. The long term implications of the Covid-19 pandemic are still emerging as this report is being written, but are expected to affect the community and the local economy, with the hospitality and tourism sectors especially hard hit. We consider that our proposal for a 3-year CPP period helps manage the uncertainty arising from Covid-19 impacts.

65. As an initial response, we have tried to reduce the price increase as far as possible and revised our growth-related investments in our final proposal. Steps we have taken in the expectation of reduced demand growth and reduced customer growth include removing or deferring selected major projects, reducing our consumer connections forecast and deferring distribution reinforcement works.

66. We expect the impact of Covid-19 to supress demand at the beginning of the CPP Period, however from RY23 we anticipate the need to recommence deferred investments to enable us to support regional growth and to ensure we can connect new customers.

67. The full impact of Covid-19 is uncertain and so we propose to establish with the Commission a methodology for managing the growth uncertainty associated with Covid-19 that could include, for example, an annual review of demand forecasts and growth-related investments based on the actual growth in demand that has occurred.

Contingent Projects

68. In the context of Covid-19, we consider that certain growth related projects/programmes have sufficient uncertainty to be considered contingent projects at this time. The majority of our Capex programme is related to safety driven renewals work (unaffected by Covid-19) 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 Input Methodologies (IMs).

69. We think the Covid-19 situation deserves special consideration. We have relatively high confidence that Covid-19 will have an impact on growth and the timing of projects creates a greater than normal case for lowering the contingent project threshold. Furthermore, in the context of a significant price rise, we want to create an opportunity to defer growth projects as much as possible and share that deferred Capex gain with consumers in the CPP period, not as part of the incremental rolling incentive scheme (IRIS) which defers a shared proportion of the saving to a later date.

70. We have done some preliminary analysis to look at the implications of Covid-19 on growth, especially in the Central Otago / Queenstown region. We looked at three growth scenarios, ranging from a very short term impact to a major impact with slow growth for many years. Given the uncertainty, we concluded that a balanced view was most appropriate, resulting in an assumption that Covid-19 would set back growth by two years, but beyond that period the growth rate would continue at pre-Covid-19 levels.

71. To manage this uncertainty, our preference would be to utilise our existing major project economic analysis framework to seek approval (through an independent verifying party), on a case-by-case basis, any major growth or connection related projects . This is not expected to be more than ten projects and the additional overhead associated with this is relatively small given our assessment framework is already in place.

72. In summary, we consider that a streamlined contingent projects arrangement could be put in place to better manage the uncertainty and risks associated with Covid-19 impacts on our growth related work programmes. This approach will ensure that the network growth related expenditure uncertainty associated with Covid-19 is treated separately from our renewal and Opex expenditure which should continue to be subject to IRIS. This will ensure that neither Aurora Energy or consumers gain or are penalised as a result of changes in expenditure timing associated with Covid-19.

1.3.6. Commerce Commission Consultation

73. The Commission has begun to engage with stakeholders on our proposal and this will continue through the remainder of 2020. Our customers and stakeholders will therefore have a further opportunity to provide feedback on our plans through this process. We will continue to engage with customers on our plans and proposed price adjustments in support of the Commission's formal process.

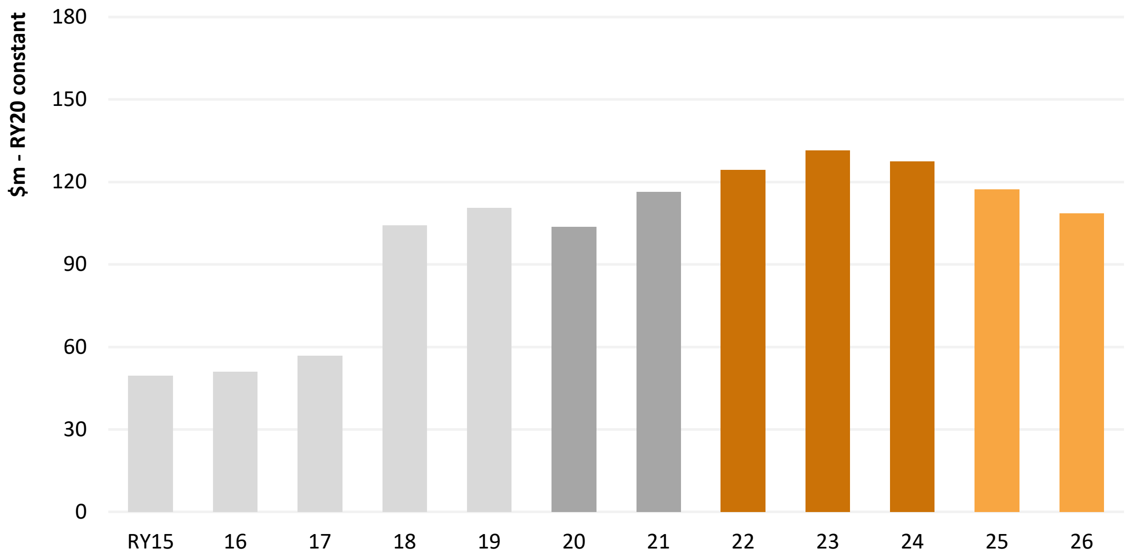
1.4. Proposed Spend

1.4.1. Our Proposed Investment

74. During the CPP Period we plan to invest $383.3million in new assets, network maintenance and operations to deliver and support our electricity distribution service. This is a 20% increase above the latest three-year period (RY18 to RY20).

75. Figure 6, below, sets out our proposed total Capex and Opex (totex) for the CPP period and equivalent historical spend.

Figure 6: Total historical and forecast totex



The colours used in expenditure charts denote:

Current period

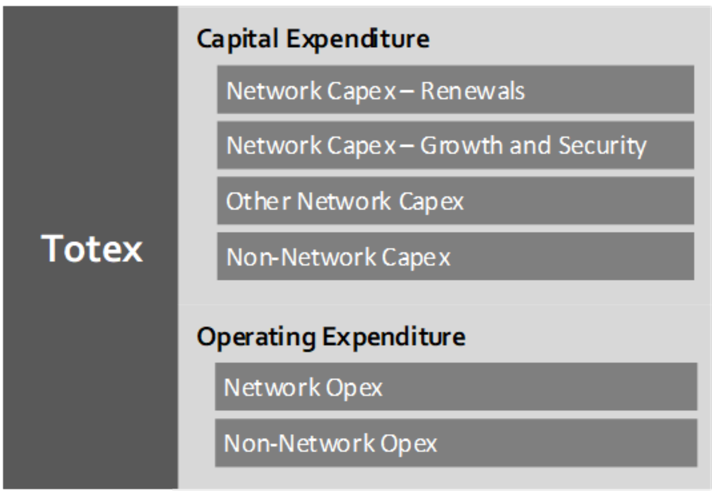
Assessment period

CPP period

Balance of 5-year review period

76. Figure 7, below, sets out our expenditure categories, each of which is made up of several expenditure portfolios that form the basis of our internal expenditure governance and budget management.

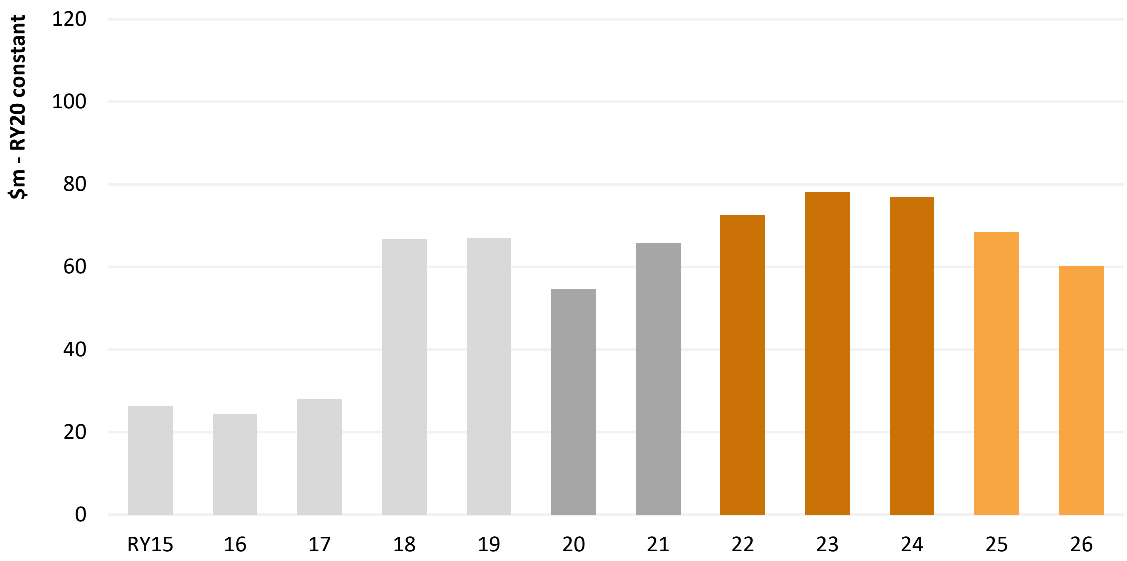
Figure 7: Expenditure categories



1.4.2. Capital Expenditure

77. During the CPP Period we plan to invest $227.7million in new assets to deliver and support our electricity distribution service. This is a 21% increase above the latest three-year period (RY18 to RY20). Figure 8, below, sets out our proposed total Capex for the CPP Period and equivalent historical spend.

Figure 8: Total historic and forecast Capex[7]



78. Points to note in relation to this Capex profile:

- Historical investments were low. The uplift depicted in RY18 coincides with the introduction of the fast track pole programme and our separation from Delta.
- We need to maintain elevated levels of renewals investment to manage the safety risk levels on our network.
- Growth and security investments enable us to support regional growth and ensure we can connect new customers, a portion of these have been deferred due to the expected impact of the Covid-19 pandemic.
- Non-network Capex includes capital investments in IT capability and systems, these will reduce over the period as we shift more of our solutions towards SaaS (software as a service).

79. We have moderated our CPP Capex forecasts through a robust challenge and review process including customer feedback, independent verification and updates to take into account potential Covid-19 impacts. Specific examples include deferring several non-critical renewal investments,

[7] The reduction in Capex in RY20 was caused by a range of factors largely outside of our control affecting some large projects, rather than any particular deliverability issue. These have included deferral of projects associated with Transpower 33kV switchboard delays at the Halfway Bush GXP, and amended plans for the new Dunedin Hospital where we diverted planning and engineering resources to the (now unneeded) relocation of North City Zone substation.

applying efficiency gains, deferring capacity-driven investments by at least two years and reducing the short-term level of investments in new connections due to the impact of Covid-19.

80. Most of our total three-year CPP spend is on renewals Capex. A large proportion of our network was constructed in the 1950s-70s period and, as many assets have an expected life of 50-60 years, a large proportion of the network has already or will soon become due for renewal.

81. An historical failure to recognise the investment needs of the network and ramp up internal capability has left us in a catch-up phase for renewals that requires a high volume of work to return network risks to acceptable levels. Once this has been achieved, investment will reduce to steady state levels.

82. Table 3 below shows the forecast spend on renewals Capex for the CPP Period. The majority of the expenditure is on poles, crossarms, distribution and low voltage conductor (overhead lines) and zone substation assets that are overdue for replacement, and which present a significant safety risk if not addressed.

Table 3: Renewal Capex and key drivers

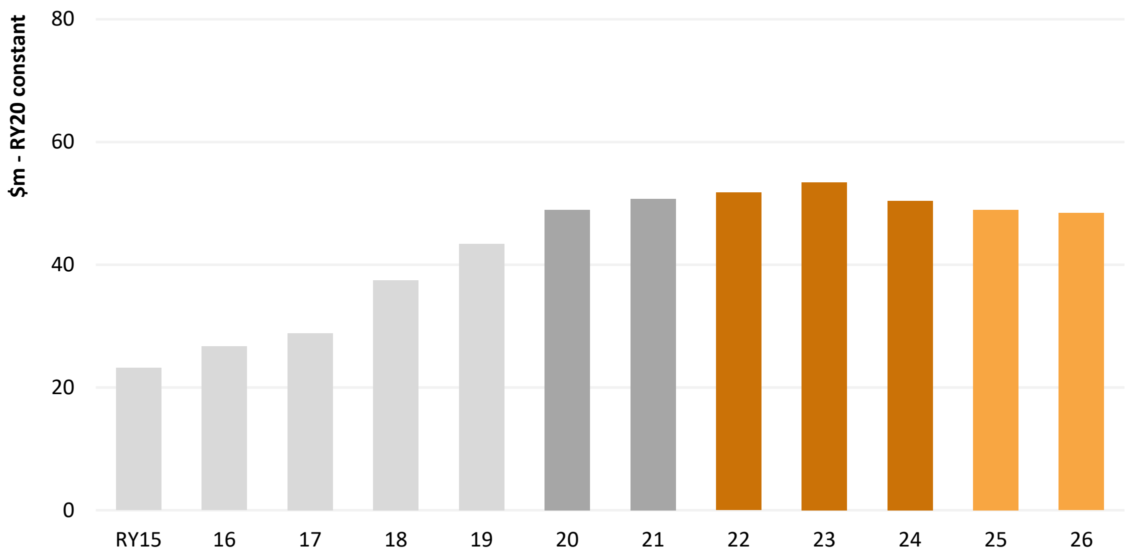
Category	3-year spend	S	C	R	O	Description
Poles	$35m	•	•	•		Replace poor condition poles, reduce the wooden pole backlog to zero by RY24, manage the public safety risk of pole failure, meet regulatory timeline for red tagged pole remediation
Crossarms	$23m	•	•			Inspect and replace poor condition crossarms, prioritising those with the greatest safety risk when overhead lines drop to the ground
Overhead conductors (lines)	$42m	•	•			Replace poor condition overhead lines to reduce safety risks associated with line drop. Remedy low clearance spans to reduce third party contact risks.
Zone Substations	$27m	•	•			Upgrade equipment to avoid worker safety risk of arc flash hazards from ageing equipment, particularly indoor switchgear, and upgrade poor condition assets to reduce reliability risk
Protection	$7m	•			•	Ensure fault protection schemes operate reliably for network operation and public safety, replace obsolete relays without manufacturer support, and install modern relays with improved functionality
Low voltage enclosures	$6m	•				Remediate poor condition enclosures to avoid exposing workers and public to safety risk
Cables	$13m	•				Replace cast iron pothead cable terminations at risk of failure and safety risk to the public

Key: S = Public or Worker Safety, C = Condition (asset health), R = Reliability; O = Obsolescence or Functionality

1.4.3. Operating Expenditure

83. During the CPP Period we plan to spend $155.6million on operational activities that support the electricity services we deliver to customers. This is a 20% increase above the previous three-year period (RY18 to RY20). Figure 9 below sets out our proposed total Opex for the CPP Period and equivalent historical spend.

Figure 9: Total historical and forecast Opex



84. Points to note in relation to this expenditure profile:

- Maintenance activity is increasing as we take action to reduce our defect backlogs and improve our inspection and condition regimes. The improved asset information from the expansion of our inspection regime will help optimise future investments.
- Vegetation management expenditure will reduce over time as we complete our first clearance cut and roll out our new proactive, cyclical approach that over time will lead to improved safety and reliability outcomes and ensure full compliance with the Tree Regulations.
- A non-network solution is proposed (Upper Clutha DER) for the first time on our network, as we seek to use a load aggregator to provide effective demand response through distributed energy resources that will manage demand growth in the Wanaka area. This will cost-effectively defer more traditional network capacity investments, while maintaining reliability service levels.
- Improving asset management capability and capacity will require additional specialised staff to efficiently deliver our work programmes and make improvement initiatives; e.g., our ISO 55000[8] programme will enable us to implement best practice asset management using a recognised international standard. Certification against standard would provide interested stakeholders with an objective basis to monitor our progress.

8 ISO 55000:2014. Asset management — Overview, principles and terminology.

- Historical Opex was suppressed due to the service arrangements in place with our sibling company Delta. The uplift in RY18 coincides with the establishment of the Aurora Energy as a standalone business.
- The increase in Opex in 2023 is attributable to the additional work that will be required to prepare our second CPP application, to take effect from 1 April 2024.

85. We have moderated our CPP Opex forecasts through a robust challenge and review process including reflecting customer feedback and independent verification. We have amended our forecasts to take into account potential efficiencies. Specific reductions include; making efficiency adjustments based on potential productivity gains from asset management improvements, increased competition amongst our service providers, better works delivery processes, and deferring some initiatives . We have also reduced forecast maintenance spend in the expectation that our renewals programme will begin to improve the overall condition of our asset fleets resulting in fewer faults and less corrective maintenance.

1.4.4. Adjustment for Future Efficiencies

86. Following consultation, we reviewed our expenditure plans extensively and made substantial adjustments in direct response to customer feedback, independent verifier feedback, and internal challenge. This outcome aligns with feedback we received from customers that we should focus on affordability.

87. We have applied a range of efficiency targets to our forecasts . Greater efficiencies will flow from developing our asset management capability and our ongoing improvements in business support activities, including improved IT capability. We are targeting gains from increased contractor productivity, improved works coordination, increased delivery productivity, better operational decision-making, and improving asset management capability as we mature our systems and processes.

1.4.5. Deliverability

88. We have significantly enhanced our capacity to deliver an increased work programme by implementing a major reform of our contracting model. As a result, we have three principal field service providers, supported by further approved contractors, competitive tendering and panel arrangements.

89. From 1 April 2019, we implemented new field services agreement with Delta, Unison Contracting and Connetics. Those arrangements ensure access to the skilled resources required to deliver our CPP programme, while providing a framework for improved service delivery and efficiency.

90. Deliverability has been a key consideration throughout the development of our CPP proposal and led us to dismiss alternative investment profiles in our consultation document that would have delivered more work sooner for better reliability, but would have been very hard to achieve in full.

91. We are confident that the CPP proposal can be delivered efficiently, given the significant commitments made by our contracted field service providers, and the availability of approved contractors supported by an enhanced internal programme management capability.

92. In addition, our analysis shows that there are sufficient additional resources and mitigation measures identified to ensure that our work programme can be delivered successfully. Where resource constraints are identified, we will work with our service providers and approved contractors to bridge those gaps.

93. As we and our service providers gain experience with the new arrangements, we expect to drive improvements over time; for example, by benchmarking cost performance and improving working practices by comparing contractor performance.

1.5. Quality Standards

94. Consistent with DPP3, we are proposing a set of quality standards based on SAIDI and SAIFI (respectively the average duration and frequency of outages) that include planned and unplanned components.

95. Unplanned reliability performance is a consequence of a number of factors including; network configuration, geography/topology, customer density, overhead versus underground, asset condition, and operational response to faults. Our network contains a mix of the above attributes, leading to a mix of reliability performance across the network. In general, the reliability of urban networks exceeds rural network performance.

96. The greatest influences we can exert on unplanned reliability performance is by effectively managing asset condition and ensuring appropriate levels of operational response. On this basis, our renewal programme and works coordination influence the number and duration of planned outages.

97. Prior to DPP3, planned and unplanned outages were grouped together for regulatory reporting and compliance testing against regulated limits. Our past reliability performance (planned and unplanned outages) compared favourably with our peers, as shown in Figure 10 and Figure 11, below[9].

[9] PricewaterhouseCoopers. Electricity information disclosure compendia

Figure 10: Historic SAIDI performance

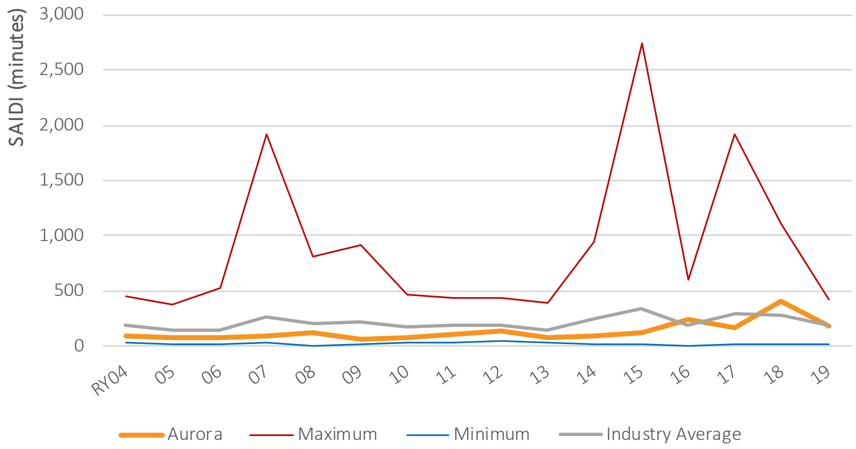
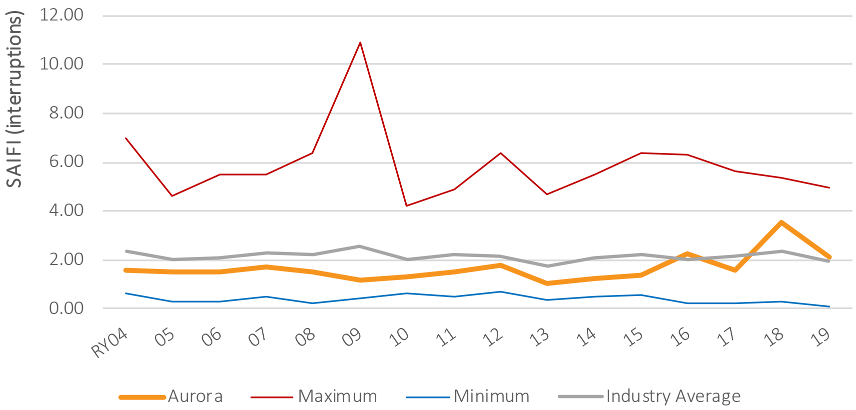


Figure 11: Historic SAIFI performance



98. While our reliability performance was below the industry average for many years, we have seen a deteriorating trend in recent years which has led to breaches of our regulatory compliance limits in 2012 and 2016 to 2019 (inclusive). A combination of factors led to the breaches including deteriorating asset health, vegetation encroachment, increased weather impacts and changes in operational response practices to better manage safety and fire related risks. In the later years our ramp up in asset renewals to improve asset health has led to a significant increase in planned outages.

99. Given the importance of reliability to customers and the consequences of regulatory reliability breaches, it is important that reliability performance targets and limits are specified at a level that is achievable and also incentivise good practice management of the network. When developing our proposed reliability performance targets and limits we modelled the impact of our safety-related renewal programme on asset health, and the number and duration of outages required to undertake the work safely. We also needed to consider the levels of reliability sought by customers.

100. Our customers told us that while reliability is very important, they are unwilling to pay more for improved unplanned reliability performance at this time. Therefore, our immediate focus is on

delivering better safety outcomes through improved asset health. This safety-driven work is likely to result in a modest unplanned reliability improvement toward the later part of the CPP period. Customers accepted the need for elevated levels of planned outages to undertake asset renewal and maintenance work.

101. Our quality path proposal is consistent with the Commission's principle for DPP3, that there should be 'no material deterioration' in network quality. It sees unplanned reliability performance stabilise in the short term, and establishes a foundation for returning, subject to customer support, to historical levels of unplanned reliability performance in the medium term.

102. We have improved our modelling capability to forecast reliability performance, measured by SAIDI and SAIFI, to improve our understanding of the root causes of reliability performance and to target improvement initiatives.

103. While there is inherent uncertainty in forecasting future reliability performance, our analysis has concluded that the Commission's DPP3 reliability standards for planned SAIDI and SAIFI are suitable for the CPP period RY22 - RY24. However, unplanned SAIDI and SAIFI require reliability standards that better reflect our circumstances and the price quality preferences of customers.

104. Our customers have said that they accept current levels of service, and we are not proposing investments directly targeted at reliability improvement – we expect that to be a focus of our second CPP proposal, subject to customer support. We acknowledge that our investment will have an impact on reliability, to the extent that our reliability performance should stabilise, with modelling supporting that view.

1.5.1. Planned Quality Path

105. Planned outages are required so we can safely access the network to maintain and replace equipment. They are notified to customers in advance via energy retailers and online and if the work affects a wide area, we talk directly to communities about what is planned and when.

106. Under our proposed plan, we forecast planned reliability remain at similar levels to the past three years' average as we continue high levels of renewal and maintenance on the network.

107. Our forecast planned SAIDI and SAIFI for the three-year CPP period is consistent with the Commission's DPP3 limit. The Commission's decision to apply the limits over multiple years will provide some flexibility in annual levels of planned work.

108. Table 4, below, shows our proposed planned quality limits for our three-year CPP period and, as required, over five years, that are the same as the Commission's DPP3 planned quality limits.

Table 4: Proposed planned SAIDI and SAIFI quality limits (identical to DPP3

Proposed Planned Quality Standards	5-year (DPP3) RY21-RY25	Annualised[1]	3-year RY22-RY24
Planned SAIDI limit (minutes)	979.80	195.96	587.88
Planned SAIFI limit (interruptions)	5.5385	1.108	3.3231

1.5.2. Unplanned Quality Path

109. Unplanned outages, or faults, reflect the underlying condition of network assets and the impact of external events such as extreme weather, trees contacting lines and cars colliding with poles.

110. Under our proposed plan, we forecast unplanned reliability to stabilise as a result of our replacing ageing poles and overhead lines, our modelling of non-asset related outages and the impact of our proposed expenditure in relation to vegetation management.

111. Figure 12 and Figure 13 below set out our forecast unplanned reliability and proposed quality limits for the CPP period. To recognise the inherent uncertainty in our models, and almost constant level of the forecast over the CPP period, we have adopted a 'flatline' target that reflects the highest annual forecast over the CPP period.

Figure 12: Historical and forecast duration of unplanned outages (SAIDI RY14-RY26)

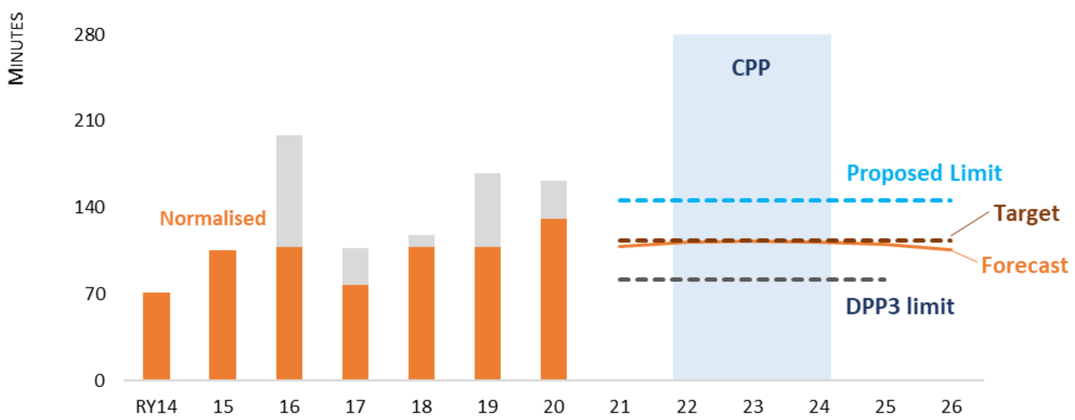
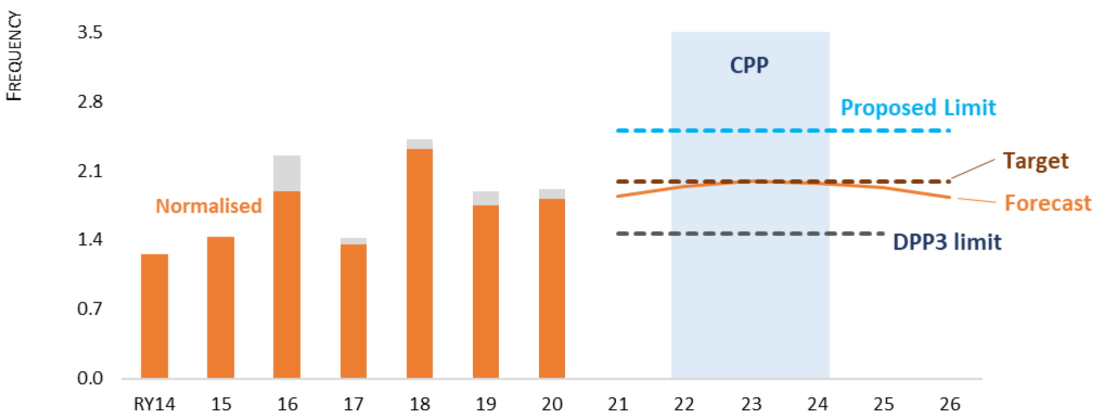


Figure 13: Historical and forecast number of unplanned outages (SAIFI RY14-RY26)



112. Table 5 below shows our proposed unplanned SAIDI and SAIFI limits.

Table 5: Proposed unplanned SAIDI and SAIFI parameters

Unplanned Interruption Quality Standard	SAIDI	SAIFI
Unplanned limit	146.29	2.5067
Unplanned boundary value	5.69	0.0737
Unplanned interruption target	113.34	1.9948
Forecast average	110.33	1.9195
Scaled standard deviation	16.48	0.2560

1.5.3. Quality of Service Measures

113. Service measures include both quality of supply (or reliability) and quality of service. Customers told us that they expected some customer services as fundamental, but affordability is a primary concern.

114. From a range of possible customer service measures, we included in our final proposal those that were either considered by customers to be essential to the service we provide or were highly valued by customers as priorities to improve or add.

115. In addition to reliability standards, our final proposal includes retention and improvement of:

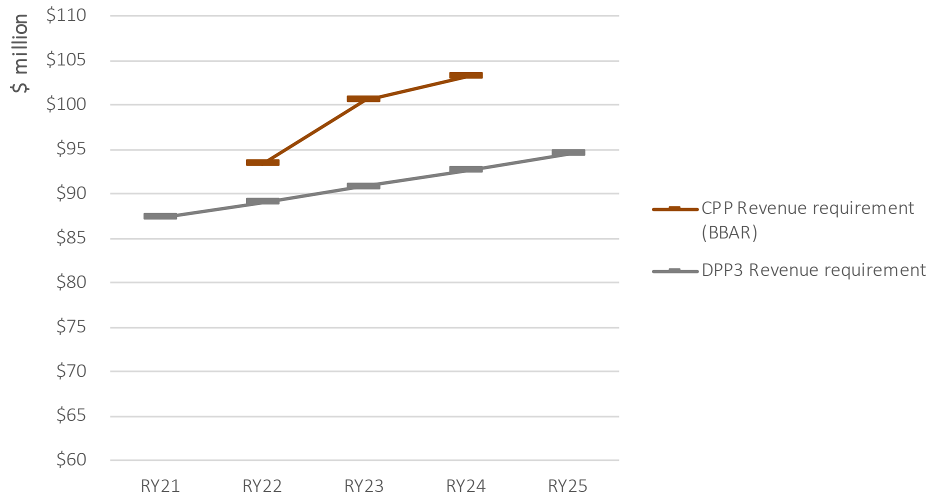
- Communication of planned and unplanned outages, continue to provide call centre and outage notification service with further enhancements to real-time updates for unplanned outages with cause and restoration times
- New connections process, continue improvements to the process for new connections and establish service level targets
- Customer Charter credit scheme, continue compensation scheme for unmet service levels and review complaints process and compensation policy.

1.6. REVENUE AND PRICE IMPACTS

1.6.1. Revenue Impacts

116. Our investment plans will impact the prices customers pay for our distribution services. If our plan is approved, our revenue will need to increase to recover the additional expenditure. This cannot be avoided if we are to remain a viable business. The 'raw' revenue requirement (Building Blocks Allowable Revenue – BBAR) resulting from our proposed expenditure is outlined in Figure 14. During the CPP period, we forecast the revenue requirement for the three years to be $297million, a 9% increase above the DPP3 revenue over the same period (2022 to 2024).

Figure 14: Revenue requirement[10] (excluding regulatory incentives)



1.6.2. Revenue Smoothing and Deferral

117. We have listened to our customers and stakeholders in considering how best to smooth our revenue recovery over the CPP period. The Customer Advisory Panel highlighted that customers take time to modify their electricity usage, including in managing their energy use in response to increased prices. Accordingly, they advocated a slower rate of increase in our charges at the start of the CPP period to provide customers with additional time to respond to the higher prices.

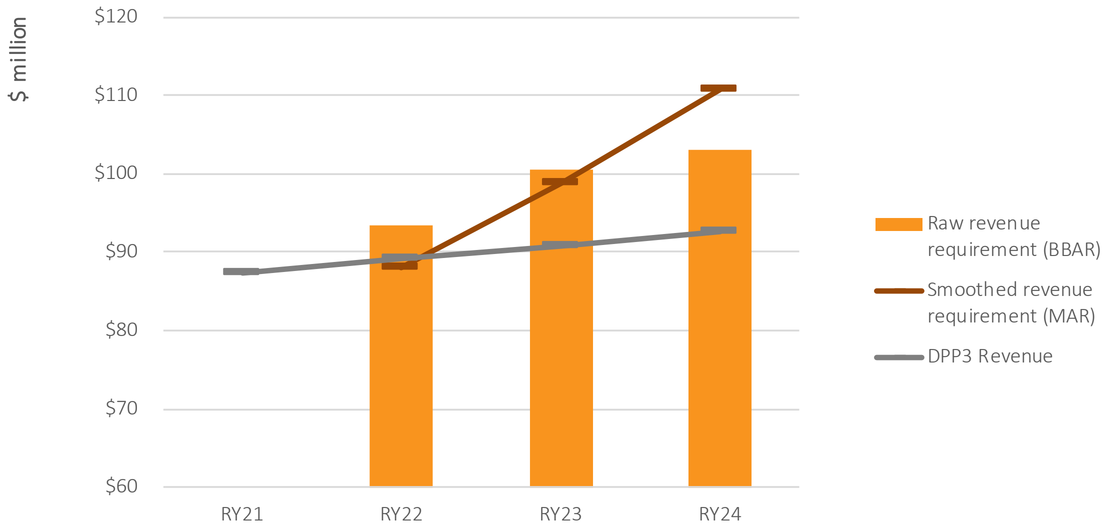
118. Our 'raw' revenue requirement tends to following the pattern of investment and is variable across the CPP period. To remove that variability, we undertake a process of smoothing, as shown in Figure 15, below. The smoothing process balances the initial starting price (P_0) and the annual rate of change in real terms. Our smoothing creates a P_0 that is as close as possible to the DPP, recognising that regulatory incentives will place upward pressure on prices[11], while maintaining an annual rate

10 BBAR refers to Building Blocks Allowable Revenue.

11 An explanation of the impact of regulatory incentives is provided in Appendix K, section K.3.4.

of change at 10% or below[12]. A potential downside of this approach is that prices at the end of the CPP may be higher than the first year of the next regulatory period (RY25)

Figure 15: Revenue smoothing (excluding regulatory incentives)



119. The impact of regulatory incentives is significant, and we have proposed to the Commission that instead of the incentive being recovered within the CPP period, we spread it over eight years (the CPP period and the next full regulatory period) in order to manage the impact on prices. This has meant the deferral of approximately $75 million over five years, reducing price increases by 11% (compared with non-deferral). In doing so we have prioritised customer affordability over the need to finance the business. However, some increase in revenue (and associated price) is unavoidable. Ensuring adequate financing and cashflow is a key criteria for the Commission as it is in the long term interests of consumers for Aurora Energy to be financially sustainable. Further information on the deferral of regulatory incentives is contained in section K.3.4.

1.6.3. Customer Price Impacts

Historic Prices

120. Our historical distribution prices were, on average, among the lowest in the country. While it is difficult to directly compare the distribution prices of different EDBs owing to the very different pricing structures that prevail, we can assess differences based on high-level measures:

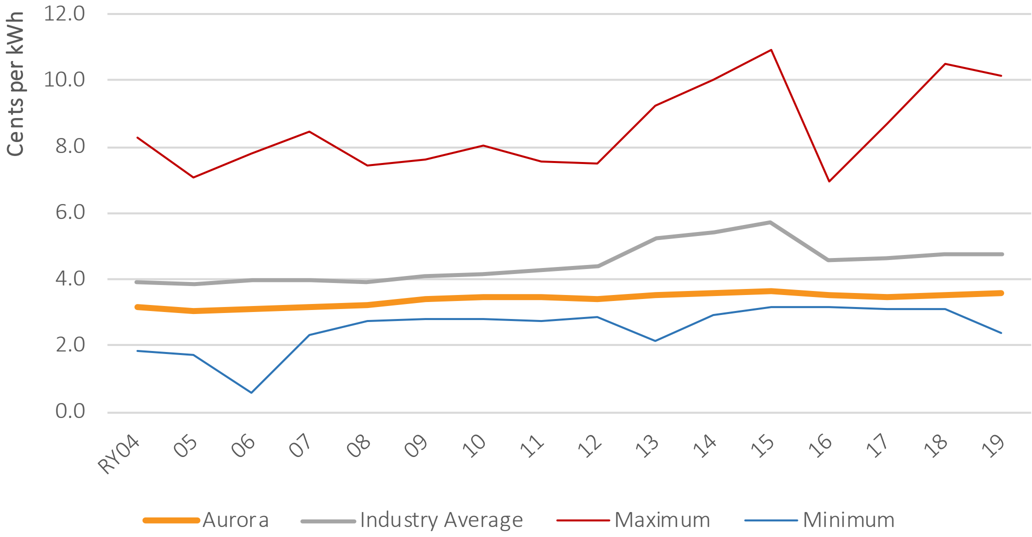
- Dollars of revenue per ICP (customer connection);
- Dollars of revenue per megawatt (MW) of coincident peak demand; and
- Cents of revenue per kilowatt-hour (kWh) of electricity delivered.

121. Figure 16, below, shows our average distribution revenue, on the basis of cents per kWh of electricity delivered to consumers (constant 2004 cents), against the industry average, maximum and

12 The rate of change, or X-factor, is explained in section 4.3.

minimum[13]. The chart clearly shows that, our distribution charges were among the lowest in the country, and virtually flat in real terms. This is primarily due to relatively low historical investment. The position is not materially changed when measured on the basis of revenue per MW of coincident peak demand or revenue per ICP (refer section K.3.1, below).

Figure 16: Distribution component of revenue - constant 2004 cents per kWh delivered

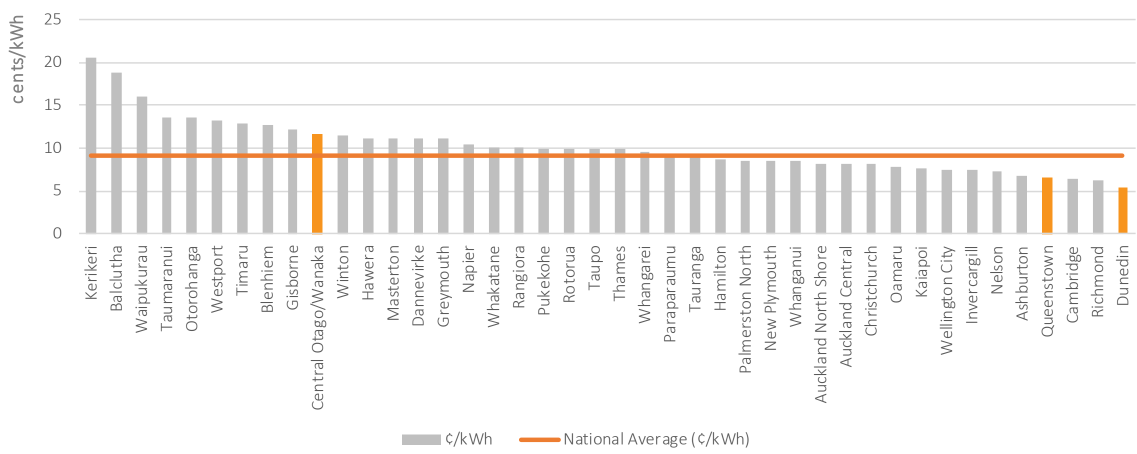


122. We have regional pricing that reflects the underlying cost-to-serve in each of our three pricing areas (Dunedin, Central Otago/Wanaka, and Queenstown), and this approach does produce regional variations.

123. Figure 17, below, shows modelling of the distribution component of residential line charges, for a typical consumer, undertaken by the Ministry of Business, Innovation and Employment as part of its Quarterly Survey of Domestic Electricity Prices (QSDEP series).

[13] PricewaterhouseCoopers. (2004 to 2019). *Information disclosure compendia*. Available from PricewaterhouseCoopers. Individual disclosures are available from distributors' websites.

Figure 17: National comparison of estimated residential line charges (distribution Component) [14]



124. Figure 17 clearly shows the regional variations, which are driven predominantly by customer density:

- The Central Otago / Wanaka pricing area has approximately 7 ICPs per kilometre of network circuit;
- The Queenstown pricing area has approximately 12 connections (ICPs) per kilometre of network circuit; and
- The Dunedin pricing area has approximately 19 connections ICPs per kilometre of network circuit.

125. Our pricing areas are defined on objective criteria, including whether logical boundaries exist based on network layout (rather than arbitrary geographical or political boundaries), whether network areas are connected and able to offer load sharing capability , or whether there are adjacent areas that could be consolidated on the basis of similar network characteristics.

126. Our current pricing philosophy is that costs of providing network assets to a pricing area (generally based on network capital and operating expenditure) should lie where they fall, and not be subsidised by consumers that do not use those assets or benefit from them. We consider that business support costs (overheads, etc.) should be spread across the entire consumer base, where scale benefits can be realised. While prices in the Central Otago / Wanaka pricing area are relatively high compared to our other pricing areas, we consider that prices have been derived in a manner consistent with our pricing philosophy and methodology, are explainable, and remain below those that would arise in a stand-alone business operating in comparable circumstances.

127. Our indicative forecast pricing is consistent with our pricing methodology that follows the guidelines for cost-reflective distribution pricing set by the regulator, the Electricity Authority. In our CPP consultation, our Central Otago and Queenstown Lakes customers told us that they dislike our regional pricing. Given this feedback, we intend to review our pricing methodology to determine

[14] Ministry of Business, Innovation and Employment. (2020). *Quarterly Survey of Domestic Electricity Prices (QSDEP)*. 15 February 2020.

whether an alternative pricing approach could, or should, be developed with the aim of consulting with customers and stakeholders in 2023.

128. Our approach to regional pricing is described in more detail in Appendix K.

Future Prices

129. Our indicative analysis shows that the additional distribution line charges of our CPP proposal compared to staying on DPP3, over the same three-year period, are approximately:

- $19 per month for an average residential customer (our consultation proposal was $25)
- $40 per month for an average business customer. (our consultation proposal was $53)

130. The actual charges will depend on the outcome of the Commission's process, how each individual customer uses the electricity network, and any updated inputs to our pricing methodology as new data becomes available.

131. Table 6 provides the estimated change in monthly distribution charges, including regulatory incentives, for residential and small business customers in each of our three pricing regions, including the forecast impact of regulatory incentives.

Table 6: Estimated average monthly change in distribution charges under our CPP proposal in constant 2020 dollars (including regulatory incentives)

Pricing region	RY22	RY23	RY24
Dunedin			
Residential	$14	$3	$4
Small Business	$35	$9	$9
Central Otago and Wanaka			
Residential	$19	$6	$5
Small Business	$31	$9	$9
Queenstown			
Residential	$13	$5	$6
Small Business	$22	$8	$10

132. The changes we made following customer consultation and verification, result in a smaller increase in customer pricing than our draft proposal for consultation, though still higher than if we stayed on DPP3.

133. Distribution charges represent only part of the total electricity bill that consumers pay, with energy, transmission, metering comprising most of the balance. In Table 7, below, we show the estimated annual percentage increase in the average total residential power bill (including incentives and other

pass-through and recoverable costs) resulting from our final proposal, against the same data for our draft proposal and if we stayed on the DPP.

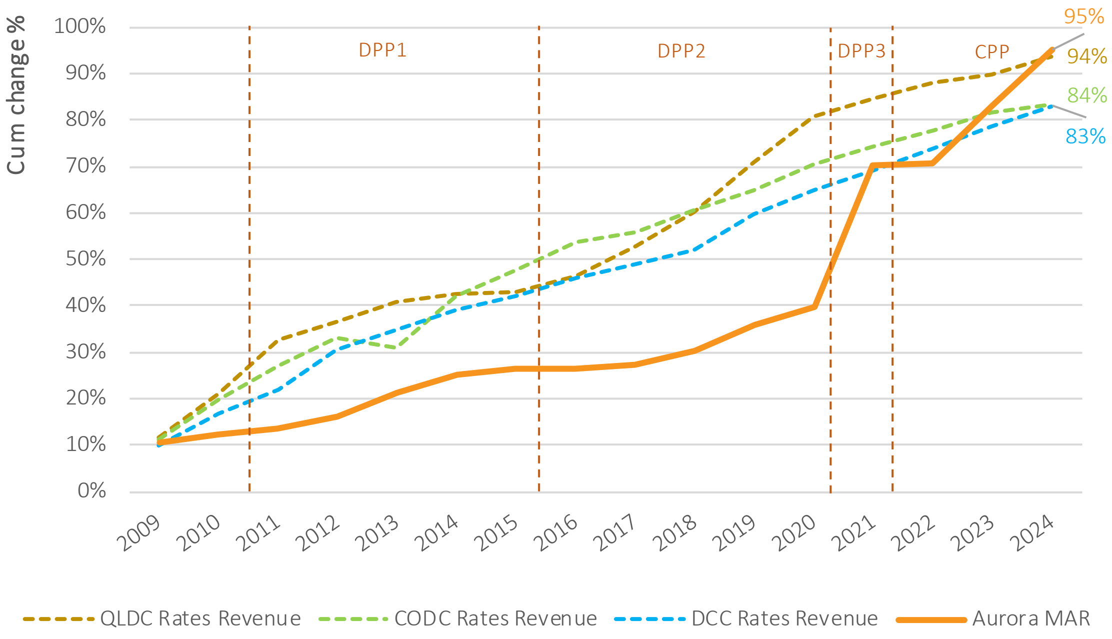
Table 7: Estimated average percentage increase in a total residential total power bill under DPP3, our draft proposal, and our final proposal (including regulatory incentives) – constant 2020 base.

Pricing region	RY22	RY23	RY24
Under DPP3			
Dunedin	0.5%	0.5%	1.8%
Central Otago and Wanaka	(0.1%)	0.1%	2.1%
Queenstown	(0.1%)	0.2%	1.4%
Under our draft proposal			
Dunedin	7.7%	3.6%	3.7%
Central Otago and Wanaka	12.1%	4.8%	5.0%
Queenstown	7.7%	3.5%	3.7%
Under our final proposal			
Dunedin	7.9%	1.9%	1.8%
Central Otago and Wanaka	10.4%	2.9%	2.8%
Queenstown	5.8%	2.2%	2.4%

134. We are undeniably catching up on needed investment, and this extra work is also reflected in our forecast revenues and prices. While we acknowledge that step changes in prices are challenging, this CPP will not see us out of step with other owners of significant infrastructure in our region, as demonstrated by Figure 18[15]. Rates revenue is a good comparison to line charge revenue, as both are generally ubiquitous across the community.

15 Data sources for this analysis are; Aurora Energy's revenue - historic information disclosures (https://www.auroraenergy.co.nz/), the Commission's DPP3 determination, Councils' rates revenue – the annual plans, 10-year plans, and 2018/19 annual reports of each respective council, and Statistics New Zealand Infoshare (https://www.qldc.govt.nz/, https://www.codc.govt.nz/, https://www.dunedin.govt.nz/, and http://archive.stats.govt.nz/infoshare/, respectively.

Figure 18: Aurora Energy historic and forecast revenue versus historic and forecast QLDC, CODC and DCC rates[16]



1.7. What the CPP will Deliver

135. Our three-year CPP proposal is in the long term interests of customers as it continues work that is essential to a safe and reliable network and which supports future improvements. Our plans will:

- make our networks safer
- address renewal backlogs and past under-investment
- deliver a reliable service, stabilising reliability at current levels
- continue to support the level of expected growth in demand and customer connections
- prepare the network in readiness for future technology uptake
- continue implementing good practice asset management with improved capability, including continuing to improve the asset data we need for sound decision-making.

136. The planned investment and supporting work programme will improve the health (condition) of critical network assets, address the backlog of legacy renewals and keep pace with emerging risks of an ageing network. Figure 19 below summarises the improvement in the health of major asset classes at the end of the CPP period, on completion of the proposed investment. The graphic includes the following indicators:

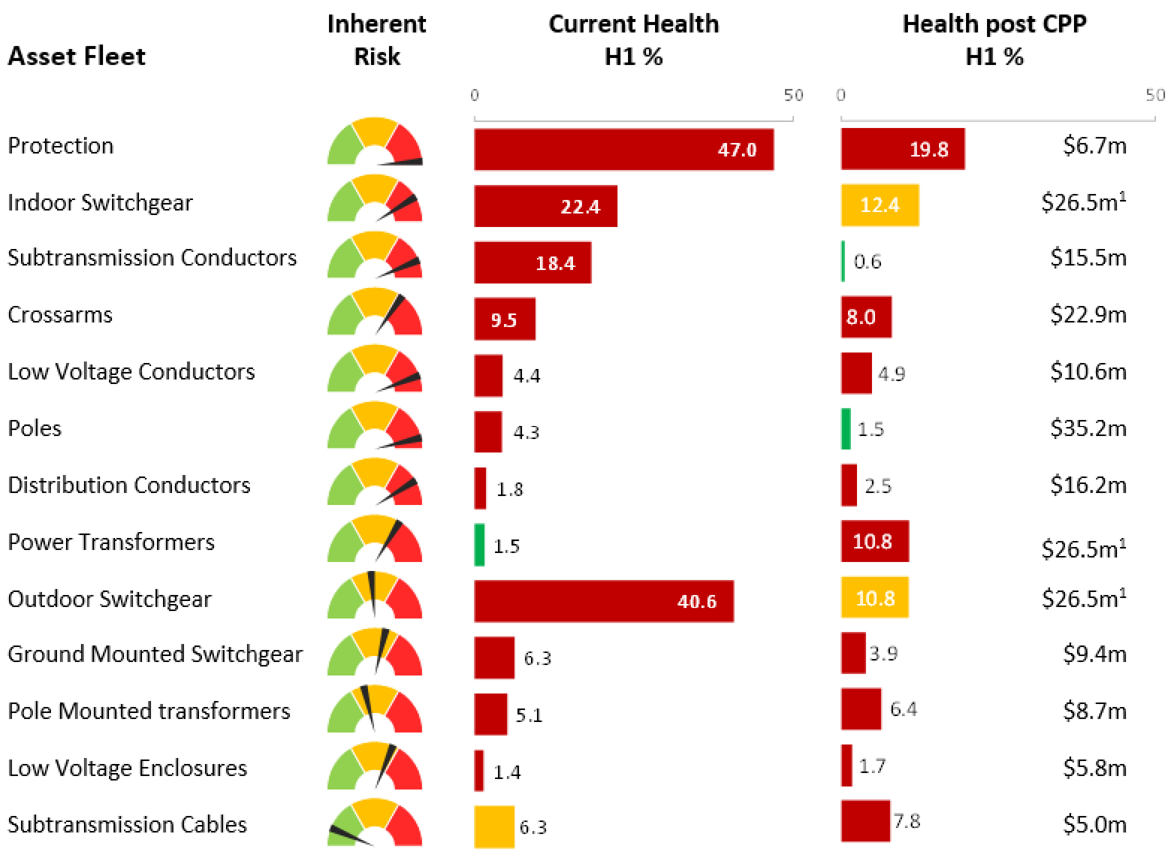
- **inherent risk**: we have categorised our asset fleets based on the potential failure consequence of a typical asset in the fleet for public or worker safety. For example, poles and overhead lines are inherently risky because their failure can place live electricity within

[16] Percentage shown in the chart are the cumulative increase, from 2008, at the conclusion of our CPP period.

unsafe distances from the public; obsolete switchgear poses an inherent risk to service providers when being operated or maintained.

- % of H1 assets: the percentages refer to assets classified as H1 that have reached the end of their useful life and that we aim to replace within 12 months
- $m is the proposed renewal capital spend on the fleet during the three-year CPP period.

Figure 19: Summary of asset fleet investment outcomes by end of CPP period RY24



137. Our proposal will stabilise reliability at current levels of unplanned and planned outages, levels that customers have told us they are largely satisfied with.

138. Under our CPP plan, we will address the gaps in our asset management capabilities as we continue to improve our asset management maturity. Our asset management improvement plan puts us on the path to achieving the internationally recognised ISO 55000 asset management standard by 2023.

139. A rigorous approach to risk assessment and commitment to asset lifecycle management and long term decision-making will avoid a repeat of the past deterioration in the state of the network.

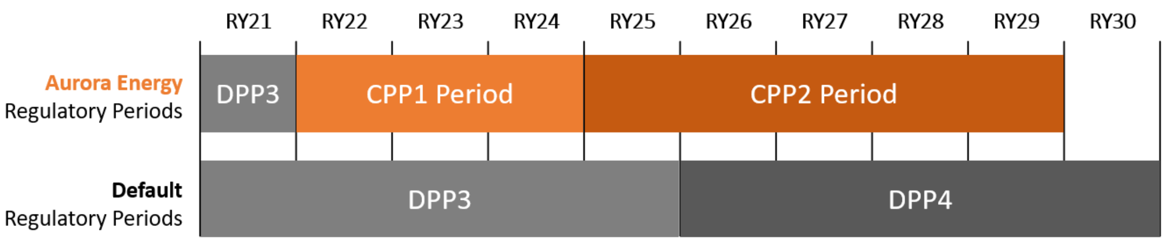
140. During the CPP delivery period, the Commission will maintain oversight and monitoring of our performance against our plans. That will ensure a high level of ongoing scrutiny by the regulator and give customers independent assurance that our spend and programme delivery is on track and

remains prudent and efficient. Our customers and stakeholders will have an ongoing role and opportunity for input as part of our CPP delivery reporting and engagement process.

141. Our CPP proposal covers three years in our longer term infrastructure renewal programme. That work will not be completed at end of three years. We intend to lodge a second CPP application for the period from 1 April 2024, resulting in combined eight year (three plus five) CPP. In this way, we can ensure that our longer term plans benefit from a further three years of capability improvement and improving asset condition information and that customers and the regulator will have a further opportunity to shape and review our plans beyond 2024.

- CPP1: during the three regulatory years (RY22 to RY24) we will focus our investments on immediately rectifying assets that pose safety risks, addressing overdue renewals, improving maintenance, capability improvements, and ensuring we can connect customers. We will make improvements in our underlying data, risk management systems and fully embed our expanded contracting and delivery frameworks. CPP1 delivery reporting will help inform stakeholders on our progress and ensure they are well placed to engage during our CPP2 consultation process.
- CPP2: for the subsequent five regulatory years (RY25 to RY29) we will propose a further set of investment plans and quality standards and engage with customers on their preferences. These plans will build on our improved asset management capabilities and more comprehensive asset information.

Figure 20: Our proposed CPP periods will run in parallel with the DPP



1.8. What Next and Feedback

142. Our CPP Application is available on our *Your Network. Your Say* website , along with information relating to our consultation activities prior to submitting our proposal. We welcome additional feedback or questions on our final proposal via the website.

143. The Commission will conduct its own customer and stakeholder consultation on our proposal as part of its review process. More information on how to get involved will be provided on the Commission's website. We encourage our customers and stakeholders to engage with the Commission's process and provide any feedback on our final proposal you wish to be considered by the Commission.

2. Application for Customised Price-Quality Path

144. This is an application (CPP Application) made by Aurora Energy Limited for a customised price-quality path (CPP), pursuant to:

144.1. section 53Q of the Commerce Act 1986 (the Act); and

144.2. the Electricity Distribution Services Input Methodologies Determination 2012 (IMs).

145. Aurora Energy is applying to modify its regulated revenue path and quality standards.

2.1. Applicant's Details

Name:	Aurora Energy Limited
Address for service:	10 Halsey Street PO Box 5140 DUNEDIN 9054
Website:	www.auroraenergy.co.nz
Contact person:	Alec Findlater General Manager Regulatory & Commercial alec.findlater@auroraenergy.nz Phone: 027 222 2169

146. All correspondence associated with this CPP Application should be directed to the nominated contact person stated above.

2.2. Application Structure

147. Aurora Energy's CPP Application comprises the following documents:

CPP Application	– Addresses the requirements of the Commerce Act 1986, as they relate to CPP applications; – Addresses the requirements of IM part 5, subpart 1, and certain aspects of subparts 4 and 5; – Explains the reasons for seeking a CPP, and the term of regulatory period sought; – Provides an overview of the CPP proposal, including proposed expenditure, quality and service standards, consumer consultation, proposal verification, revenue and price impact;

	– Describes how we have developed and tested our proposal; – Addresses compliance matters, including IM modifications and exemptions, audit, certification and compliance checklists; and – Provides cost allocation, capital and operating expenditure and demand forecast schedules.
2020 Asset Management Plan	– Aurora Energy's updated full asset management plan, consistent with, and supporting, the CPP proposal.
CPP Financial Model	– Addresses the requirement of IM clause 5.4.7 and calculates the Building Blocks Allowable Revenue (BBAR).
Financial and Modelling Information Report	– Addresses the requirements of IM part 5, subpart 1; and – Provides context and explanation for the information provided in the CPP Financial Model and, where applicable, CPP financial schedules.
Consultation Report	– Addresses the requirements of IM clauses 5.1.2 and 5.5.1.
Independent Verifier's Report	– Addresses the requirements of IM clauses 5.1.3 and 5.5.2.

2.3. Requirements of the Commerce Act 1986

148. Section 53Q of the Act requires that a proposal for a customised price-quality path must:

148.1. comply with the input methodologies referred to in section 52T(1)(d) relating to the process for, and content of, customised price-quality path proposals;

148.2. be made within the period, or by the annual date, specified for the purpose in the section 52P determination;

148.3. include the standard application fee for customised price-quality path proposals; and

148.4. apply or adopt all relevant input methodologies.

149. Section 53Q also requires that a regulated supplier:

149.1. may make only 1 proposal during a regulatory period, and may not make a proposal within the 12 months before a default price-quality path is due to be reset; and

149.2. must make its proposal publicly available as soon as practicable after it has been made to the Commission.

150. Aurora Energy's compliance with these requirements is noted below.

2.3.1. Compliance with the Input Methodologies

151. Aurora Energy has complied with the IMs, subject to modifications and exemptions granted by the Commission on 29 May 2020 and 5 June 2020 and detailed in section 3.5 of this document.

152. Aurora Energy has made an assessment of its compliance with the IMs, which is recorded in compliance checklists in Appendix T and Appendix U. The compliance checklists provide a reference to the relevant sections of documents comprising this CPP Application that demonstrates compliance with each pertinent IM requirement.

153. Additionally, Audit New Zealand has audited the financial model for compliance with the IM requirements (part 5, subparts 3 and 4).

2.3.2. Application Date

154. Clause 7.1 of the Electricity Distribution Services Default Price-Quality Path Determination 2020 provides that where a non-exempt EDB elects to propose a customised price-quality path which commences 1 April 2021, that non-exempt EDB must submit a proposal for the customised price-quality path no later than 12 June 2020.

155. This CPP Application is made on 12 June 2020.

2.3.3. Application Fee

156. Payment of $23,000 has been made by direct deposit, being the application fee prescribed in clause 2(aa) of the Commerce Act (Fees) Regulations 1990.

2.3.4. Applies or Adopts all Relevant IMs

157. Aurora Energy's CPP Application applies or adopts all relevant IMs, except to the extent that those requirements have been modified or exempted, or are the subject of a modification and exemption request submitted prior to the submission of this CPP Application.

158. Aurora Energy's compliance with the IMs is recorded in compliance checklists in Appendix T and Appendix U.

2.3.5. CPP Application Made Publicly Available

159. Aurora Energy proposes to make this CPP Application available on its website on 12 June 2020.

160. Aurora Energy does not intend to make publicly available the documents relied upon by the independent verifier, and which are contained in the SharePoint data room. Those are internal and confidential Aurora Energy documents, the disclosure of which would prejudice Aurora Energy's commercial interests.

3. IM Requirements: Part 5, Subpart 1

161. Part 5, subpart 1 of the IMs specifies that a CPP application must contain:

161.1. evidence on consumer consultation;

161.2. verification-related material;

161.3. audit and assurance reports;

161.4. certification;

161.5. information on modifications or exemptions of information requirements; and

161.6. information specified in part 5, subpart 4 (refer section 4, below).

162. The following sections explain how Aurora Energy has complied with those requirements. Aurora Energy's compliance with the IMs is further recorded in compliance checklists in Appendix T and Appendix U.

3.1. Consumer Consultation

163. IM clause 5.1.2 requires Aurora Energy to provide specified information relating to its consultation with consumers.

164. Appendix C of this CPP Application document summarises Aurora Energy's consultation process, including; how consumers and stakeholders were consulted, the feedback received through consultation, and Aurora Energy's response to feedback received through consultation.

165. Detailed information on aurora energy's consultation process is provided in the Consultation Report that forms part of this CPP Application.

3.2. Verification Material

166. IM clause 5.5.2 requires Aurora Energy to provide the verifier with:

166.1. the materials required by the verifier to verify the CPP proposal in accordance with the terms of its engagement and Schedule G, and that Aurora Energy intends to submit to the Commission as a CPP proposal;

166.2. upon the verifier's request, the information described in clause D10 of IM schedule D pertaining to identified programmes after the verifier has notified Aurora Energy of its selection of identified programmes;

166.3. any information requested by the verifier pursuant to the verifier's right to ask for such information pursuant to its deed of engagement, and as specified in clause F6(2)(d) of IM schedule F; and

166.4. in advance of the verifier's selection of identified programmes, summary information on the forecast projects and programmes, in the format specified in Table 1: Projects and programmes of the regulatory templates.

167. Section 2.3 of the verifier's report describes the process undertaken by the verifier.

168. The information provided to, and relied upon, by the verifier in the preparation of its verifier's report is contained in Appendix I of the verifier's report.

169. Clause 5.1.3 requires that Aurora Energy provide, as part of its CPP Application:

169.1. any information relating to the CPP proposal, other than information required to be included in a CPP proposal by Subpart 4, provided to the verifier by or on behalf of the CPP applicant, pursuant to IM clauses 5.5.2(3)(a)-(c) and 5.5.2(3)(e); and

169.2. any other information relied upon by the verifier relating to the CPP proposal pursuant to IM clause 5.5.2(3)(d).

170. The information responsive to the above requirements is the information set out in Appendix I of the verifier's report. The information in Appendix I and relied upon by the verifier in preparing its verifier's report (Table I.1) has been made available to the Commission in the SharePoint Data Room, along with additional relevant supporting material.

171. Aurora Energy confirms that the certificate issued by the verifier relates to verification of the relevant parts of the CPP proposal as submitted to the Commission, as required by IM clause 5.1.3(2).

172. In accordance with IM clause 5.4.32, the verifier's terms of engagement and invoices, along with Aurora Energy's records of payment and the initial procurement documents, have been provided to the Commission in the SharePoint data room.

173. Further information on verification is given in Appendix C.

3.3. Audit and Assurance

174. IM clause 5.1.4 requires Aurora Energy to provide an audit report in respect of an audit or assurance engagement undertaken of the matters specified in clause 5.5.3.

175. The Auditor General appointed, and Aurora Energy engaged, Audit New Zealand to perform an assurance engagement of the matters specified in IM clause 5.5.3. Audit New Zealand's assurance engagement report is provided in Appendix B of this application document.

176. In accordance with IM clause 5.1.4(3), Aurora Energy confirms that the assurance engagement report provided by Audit New Zealand relates to the CPP proposal as submitted to the Commission.

177. In accordance with IM clause 5.4.32, the independent auditor's terms of engagement and invoices, along with Aurora Energy's records of payment, have been provided to the Commission in the SharePoint data room.

3.4. Certification

178. IM clause 5.1.5 requires Aurora Energy to provide certificates recording the certifications specified in IM clause 5.5.4.

179. In accordance with IM clauses 5.1.5 and 5.5.4, Appendix A contains certificates executed by Aurora Energy's directors.

3.5. Modifications and Exemptions Granted

180. On 27 March 2020 and 30 April 2020, Aurora Energy requested modifications and exemptions (M&Es) to certain IM requirements, pursuant to IM clause 5.1.7. The Commission approved IM M&Es on 29 May 2020 and 5 June 2020.

181. IM clause 5.1.8 requires Aurora Energy to provide the following information regarding M&Es in its Application:

181.1. copies of the Commission's approvals. These are provided in Appendix R.

181.2. a list of the approved M&Es that Aurora Energy has elected to apply in its Application. These are listed in Appendix S.

181.3. evidence that any conditions upon which approval has been granted, have been met. The conditions imposed on approval of M&Es are to be satisfied post-submission and therefore no evidence is provided in our Application.

181.4. An indication, at the relevant locations within the document or documents comprising the CPP application, as to where the modifications or exemptions have been applied. This information is provided in the Financial Modelling and Information report.

3.6. IM Variations

182. In addition to the IM M&Es described above, on 1 June 2020 we requested that the Commission grant three IM variations, in accordance with section 53V(2)(c) of the Commerce Act 1986. There are:

- A variation to permit Aurora to recover the prudently incurred costs of its network remediation programme in disclosure year 2021 that are above the DPP allowance. This variation, if granted, will also allow Aurora Energy to avoid future negative IRIS incentive adjustments (penalties) as a consequence of exceeding the DPP3 expenditure allowances in RY2021.

- A modification to permit Aurora to spread the impact of the Opex IRIS incentive over two regulatory periods.. This will help us better manage price shock to consumers as a consequence of the different treatment of the Opex IRIS incentive under a CPP.
- A variation to the cost allocation method used to determine the CPP Opex forecast to reflect Aurora's expected change to Opex sharing arrangements during the CPP period, as we cease providing shared services to a related party.

183. While these variations have not been approved prior to submission of our CPP Application, we have listed the proposed variations that we have relied upon in preparing our CPP proposal, in Appendix S.

4. IM Requirements: Part 5, Subpart 4

184. IM clause 5.4.1 requires that Aurora Energy's CPP proposal must contain, in all material respects, the information specified in IM subpart 4.

185. The principal information requirements of IM subpart 4 are satisfied by the following documents, which form part of Aurora Energy's CPP proposal:

185.1. CPP Application (this document);

185.2. CPP Financial Model; and

185.3. Financial Modelling Information Report.

186. Appendix A of this CPP Application document sets out detailed document references supporting the information requirements specified in IM subpart 4. This document addresses only those requirements of IM subpart 4 that are not otherwise addressed elsewhere.

4.1. Duration of Regulatory Period

187. Section 53W(2) of the Act allows the Commission to set a CPP Regulatory Period of less than 5 years, but not less than 3 years, if it considers this would better meet the purpose of Part 4 of the Act. IM clause 5.4.4 requires that Aurora Energy state the duration of the CPP Regulatory Period sought, if less than 5 years, and provide an explanation as to why that duration better meets the purpose of Part 4 of the Act than 5 years.

188. Aurora Energy requests that the Commission set a CPP Regulatory Period of 3 years.

189. Aurora Energy considers that a CPP Regulatory Period of 3 years better meets the purpose of Part 4 of the Act than 5 years, for the following reasons:

189.1. Aurora Energy's expenditure has increased significantly in advance of our CPP proposal. This has been largely in response to Aurora Energy's historic under-investment in the network, which has resulted in deterioration of network assets that now requires remediation (as set out in detail in our 2018 AMP and 2019 AMP update). Our current focus is on investing to reduce the level of risk on the network. This will need to be facilitated by improvements in our delivery capability and supporting processes. In due course we expect our expenditure requirements to revert to a long-term sustainable steady state. However, the exact timing is uncertain.

189.2. In parallel, we are working on improving our asset data and asset management maturity in order to support network planning and expenditure forecasting. As the Commission knows, we are on an asset management maturity journey starting from a comparatively low base.

189.3. As with other EDBs, the accuracy and granularity of our forecasts will vary over time. However, we consider that Aurora's current circumstances mean that accurately forecasting medium- to long-term future expenditure is particularly challenging. The combination of the step change in our investment requirements in the past several years and our relative lack of asset management maturity presents a challenge for forecasting expenditure over a five year regulatory period.

189.4. We have put in place comprehensive plans for the next three years primarily focussed on prudent asset renewal and stabilising network performance and have a high degree of confidence in our forecasts for the first three years of the CPP period (RY2022 – RY2024). However, we do not have the same level of confidence in our forecasts beyond RY2024. We believe a three year period will ensure better outcomes for customers over the medium term by reducing the potential for less than optimal investments.

189.5. We therefore consider that, under a five year CPP, there would be a significant risk of over or under-recovery in RY2025 and RY2026. If Aurora were to over-recover its costs in RY2025 and RY2026 this would clearly be disadvantageous to consumers as Aurora would be overcompensated in those years. This is clearly contrary to section 52A(1)(d). But, equally, there is a risk that Aurora could under-recover its costs in RY2025 and RY2026. This also represents a risk for both Aurora and consumers. If Aurora is prevented or unable to recover its expenditure, Aurora will not maintain financial stability. This weakens incentives to invest in network assets, contrary to section 52A(1)(a). Cost recovery is a particularly acute issue for Aurora given the funding constraints it is currently operating under.

190. Accordingly, Aurora considers that in these circumstances a three year CPP period is for the long-term benefit of consumers and better meets the Part 4 purpose, and the Commission should therefore exercise its discretion to grant a three-year CPP period.

4.2. Proposed Building Blocks Allowable Revenue

191. IM clause 5.4.7(2) requires that Aurora Energy's CPP proposal must contain all data, information, calculations and assumptions used to determine building blocks allowable revenue before tax and BBAR after tax for each disclosure year of the next period.

192. IM clause 5.4.7(4) requires that, where this information is included in a CPP proposal in a spreadsheet format, the information must be cross-referenced in the text of the CPP proposal document. Appendix T of this CPP Application document contains a compliance checklist that provides the required cross-reference, indicating where in the CPP Financial Model the required information can be found.

4.3. X-Factor

193. IM clause 5.4.8(3) requires that Aurora Energy must apply the X factor that is defined in its DPP determination (0%); however, IM clause 5.4.8(4) provides that Aurora Energy may apply a different X factor provided that an explanation and supporting evidence is given as to why that would better meet the purpose of Part 4 of the Act.

194. Aurora Energy proposes, and has applied, an X factor of -10%.

195. Aurora Energy considers that the X factor stated in paragraph 194 better meets the purpose of Part 4 of the Act than the DPP X factor, for the following reasons:

   195.1. The X-factor determines the annual rate of change in MAR, in real terms, across the CPP period. However, in the case of our CPP application, the impact of the Opex IRIS is significant, due to the different treatment of that incentive under the transition from a DPP to a CPP. This is explained further in section K.3.4 of Appendix K.

   195.2. The Opex IRIS transitions from a negative incentive adjustment of $18.5 million in RY2021, to a positive incentive adjustment of $10.8 million in RY2022.

   195.3. We have set the X-factor to minimise the change in MAR between RY2021 and RY2022, having regard for the impact of the Opex IRIS incentive adjustment. If the X-factor was reduced, then the starting MAR for RY2022 (and therefore the step off the DPP) would be higher, creating a higher risk of price shock for consumers.

   195.4. In proposing the X-factor, we have taken into consideration the Commission's preference, expressed in the DPP3 reset reasons paper, to avoid rates of change exceeding 10% in real terms.[17]

   195.5. If the DPP X-factor was to be maintained, there would either be a significant (and probably untenable from a consumer price shock perspective) initial increase in prices at the beginning of the CPP period to allow Aurora Energy to recover its BBAR. Alternatively, BBAR would have to be recovered over a longer period than the CPP period, contrary to the requirements of the IMs.

   195.6. Accordingly, we consider that the proposed X-factor better meets the purpose of Part 4 of the Act than the DPP X factor, as it preserves Aurora Energy's incentive to invest, including in replacement, upgraded and new assets, while minimising price shocks to consumers, to the extent possible within the price-quality path framework and the precedents of past price-quality determinations.

17 Commerce Commission. (2019). Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision; Reasons Paper. 27 November 2019. Paragraph 6.10, p 116.

4.4. Schedule B: Cost Allocation Information

196. IM Clause 5.4.9 requires Aurora Energy to provide the information in Schedule B of the IMs. Schedule B is provided in Appendix N of this CPP Application document.

4.5. Schedule D: Capex, Opex, Demand and Network Qualitative Information

197. IM clause 5.4.28 requires that the information in IM schedule D must be contained in a CPP proposal and provided in accordance with the requirements of that schedule. Clause D2 of IM schedule D specifies instructions for providing that information

198. Aurora Energy has provided a table in Appendix U of this CPP Application document that satisfies the information requirements by:

198.1. providing a reference to the place where, in the CPP proposal, a response is provided; and

198.2. gives the title and page reference to any separate document identified in response, including in the case where the document in question is provided in the CPP proposal.

199. Clause D3(1) of IM schedule D requires that Aurora Energy provide:

199.1. the current organisational structure of the EDB and a description of any separate organisation used to manage Capex and Opex; and

199.2. the number of full time equivalent employees, employed by the applicant, broken down by business units.

200. Aurora Energy has provided the required organisational information in Appendix P of this CPP Application document.

4.6. Schedule E: Capex, Opex, Demand and Network Quantitative Information

201. IM clause 5.4.29 requires that Aurora Energy's CPP proposal must the information specified in the regulatory schedules (IM schedule E), and that information must be:

201.1. in spreadsheet format whereby each item of data is linked between all cells to which it is relevant, irrespective of whether such cells are on the same or different tabs; and

201.2. provided in accordance with the instructions specified in IM clause 5.4.30.

202. The regulatory templates specified in IM schedule E are provided in Appendix O of this CPP Application document.

APPENDICES

Appendix A. Director's Certificate

In accordance with clause 5.5.4 of the Electricity Distribution Services Input Methodologies Determination 2012 (Determination), we, Stephen Richard Thompson and Margaret Patricia Devlin, being directors of Aurora Energy Limited (Aurora Energy), certify in respect of Aurora Energy:

Information of a quantitative nature

that, in the case of all information of a quantitative nature, other than forecast information, provided in accordance with Part 5 of the Determination, we believe that:

a) the information was derived and is provided in accordance with the relevant requirements; and

b) it properly represents the results of financial or non-financial operations as the case may be.

Information of a qualitative nature

that, in the case of all information of a qualitative nature, other than forecast information, provided in accordance with Part 5 of the Determination, we believe that:

a) the information is provided in accordance with the relevant requirements; and

b) it properly represents the events that occurred during the current period.

Forecast information

that, in the case of all forecast information provided in accordance with Part 5 of the Determination, we believe that:

a) the information was derived and is provided in accordance with the relevant requirements; and

b) the assumptions made are reasonable.

Verification and audit

that, to the best of our knowledge, the verifier was engaged by Aurora Energy in accordance with Schedule F of the Determination;

that, to the best of our knowledge, Aurora Energy provided the verifier with all the information specified in Part 5 of the Determination, including its schedules, relevant to Schedule F of the Determination;

that, to the best of our knowledge, the information described in clause 5.5.2(3)(e) of the Determination was provided to the verifier in advance of the verifier's selection of identified programmes;

that, to the best of our knowledge, the:

a) matters the auditor was engaged to audit included the matters specified in clause 5.5.3 of the Determination; and

b) auditor was instructed to report on at least the matters described in clause 5.1.4 of the Determination; and

that the:

a) audit report provided pursuant to clause 5.1.4 of the Determination;

b) verification report provided pursuant to clause 5.1.3 of the Determination; and

c) other certifications required by this clause,

all relate to the same CPP proposal.

Stephen Richard Thompson	Margaret Patricia Devlin
Director	Director

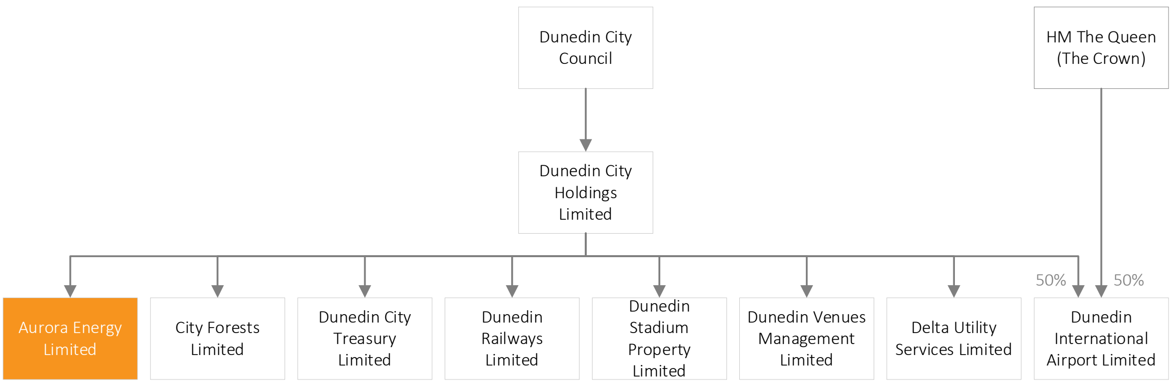
Appendix B. Ownership, Governance and Risk

203. This appendix describes Aurora Energy's ownership, governance and management structures, and associated processes. Fundamental to good electricity industry practice is our approach to managing risk, both from business context and, more specifically, from the context of managing network asset risks. This is particularly important in Aurora Energy's case, as we have a relatively high proportion of assets at, or approaching, end-of-life and which need to be appropriately managed from risk perspective. Accordingly, this appendix provides an overview of our risk management approach

B.1. Ownership

204. Aurora Energy Limited is a wholly owned subsidiary of Dunedin City Holdings Limited, which is owned by the Dunedin City Council. Our directors are appointed by our shareholder to govern and direct our activities.

Figure 21: Aurora Energy ownership structure



B.2. Vision, Mission and Values

B.2.1. Vision

205. Our vision is to be…

"A respected local partner recognised for providing essential electricity services to support the future growth and wellbeing of our communities."

B.2.2. Mission

206. Our mission is to…

"Deliver electricity to our communities when and where it's needed, safely, reliably and efficiently"

B.2.3. Values

207. To support our vision and mission, we focus on ensuring that our conduct, as a team, is consistent with our five core values, depicted in Figure 22, below.

Figure 22: Aurora Energy's values

B.3. Governance

B.3.1. Board

208. Our Shareholder, Dunedin City Holdings Limited (DCHL), appoints Aurora Energy's directors.

209. DCHL also appoints an intern director as part of an initiative, developed in conjunction with the Institute of Directors, to increase the talent pool of potential company directors. Intern directorships are unpaid, but provide aspiring directors with the opportunity to shadow board members, gain governance experience, and provide an insight into the role of directors.

210. Aurora Energy's current directors are:

- Mr Stephen Thompson (Chair)
- Mrs Margaret Devlin
- Mrs Wendie Harvey
- Mr Brenden Hall
- Mr Jon Foote (Intern)

211. One of the key activities of the Board, as it related to our CPP proposal, is the board's oversight of expenditure. The Board approves a set of delegated financial authorities to ensure, among other things, that Aurora Energy's investments are appropriately reviewed and challenged.

212. Under the financial delegations policy, budgeted capital expenditure up to $100 thousand is delegated to relevant executive managers to review and authorise, and the Chief Executive is authorised to review and approve capital expenditure up to $500 thousand. All capital expenditure above the Chief Executive's delegated authority is reviewed, challenged and approved by the Board.

B.3.2. Board Subcommittees

213. Our Board has established a number of subcommittees. Subcommittees comprise all directors, but have a different Chairperson. Subcommittees provide directors with opportunities to focus, at depth, on specific topics that are critical to the business.

214. Aurora Energy's Board subcommittees are:

- Audit and Risk (Mrs Devlin – Chair)
- Health and safety (Mrs Harvey – Chair)
- Remuneration (Mr Thompson - Chair)

B.3.3. CPP Governance Committee

215. At the time we embarked on developing our CPP proposal, the Board established a further subcommittee – the CPP Governance Committee. Unlike the standing subcommittees, the CPP Governance Committee has a finite term, designed to conclude once the Committee makes its final determination on our CPP proposal.

216. The purpose of the subcommittee is to provide governance oversight of the preparation of the CPP proposal, and to be able to provide a high level of scrutiny and challenge as the proposal has been developed. Ultimately, Directors are required to make the certifications set out in Appendix A to this application, and require a sufficient depth of knowledge and understanding of our CPP proposal, in order to meet the standard of inquiry required for certification.

217. The CPP Governance Committee has met frequently throughout the development of our CPP proposal. In the last six months, the Committee has met at least monthly, and prior to that, the Committee met bimonthly, with CPP matters being an agenda item at regular Board meetings in months that the Committee did not meet.

218. The CPP Governance Committee also met with the independent verifier, shortly after appointment, to raise its awareness of how independent verification would be conducted and progress as we refined and finalised our proposal. The Committee Chair also met regularly with the independent auditor to understand the audit status, and to ensure that the independent auditor was getting all the information it required from management.

219. The CPP Governance Committee has brought in expert external advisors, where needed, to provide detailed oversight of specific matters (for example, audit conduct).

220. The CPP Governance Committee has reviewed, challenged and approved:

- the proposed term of our CPP (three-year versus five-year);
- our consultation strategy;
- our planned investment forecasts and underlying modelling assumptions, prior to:
  - consultation;
  - independent verification;

- submission of our proposal, including post-consultation and post-verification moderations;

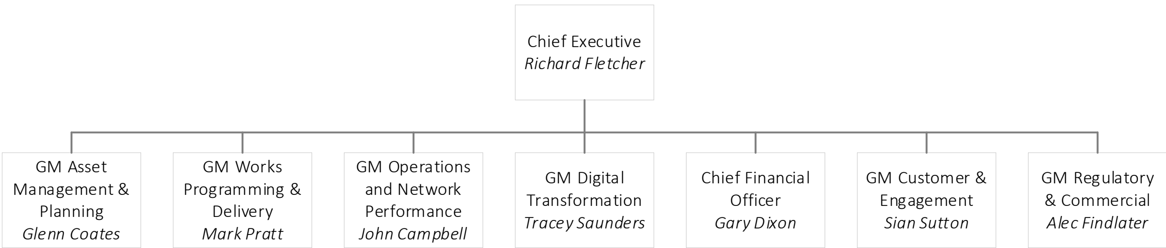
– our proposed quality standard; and

– our deliverability approach.

B.4. MANAGEMENT

221. Aurora Energy has an executive management team of eight, including the Chief Executive, which is organised along functional lines. The management structure is depicted in Figure 23, below.

Figure 23: Aurora Energy's Executive Leadership Team



222. Full organisation charts for the business, organised by business unit, are provided in Appendix P.

B.4.1. Executive Governance and Oversight Arrangements

223. We have established a series of executive governance forums, designed to provide detailed management oversight of the key business performance areas. These are:

– **Health, Safety and Wellbeing.** To ensure that Health, Safety and Wellbeing has appropriate focus within the company, by regularly engaging in assurance processes around H&S risk assessment and mitigation, safety performance and metrics, safety systems, staff wellbeing, staff capability, staff competency, safety leadership and business safety culture.

– **Technology and Digital Transformation.** To provide high level governance and oversight of ICT activities with the aim of ensuring that ICT activities are successful in supporting the overall strategy and goals of the business.

– **Work Delivery:** To ensure that the annual integrated works plan and customer initiated work (CIW) work has the appropriate focus and support within the company to be successfully delivered in a CPP environment, by regularly reviewing all major projects and programmes of works, engaging in assurance processes around reporting, procurement, budget, scope and time control, and ensuring our customer expectations are met.

– **Operational Performance and Network Reliability.** To ensure that Aurora Energy complies with our quality standards; delivering our operational performance and network reliability commitments.

– **Business and Financial Performance.** To ensure Aurora Energy's strategy and business plan is refreshed, at least annually, in accordance with the approved business planning cycle, performance targets supporting the achievement of strategic objectives are in place, and key performance indicators are reviewed regularly to provide clear 'lines of sight' and improvement opportunities.

- Risk and Assurance. To support and sustain an internal environment in which risk management and information reporting processes provide effective assurance to stakeholders, deliver a high level of integrity in management reporting, and ensure risks are treated consistently and proactively across the business.

B.5. Risk

B.5.1. Risk Management Approach

224. Aurora Energy has a flexible, systemic process, based on ISO31000[18], to identify, assess, control, and monitor risks throughout the business lifecycle. The process is cyclical requiring us to be continually risk aware.

225. To support this approach, we developed a Risk and Control Management (RCM) standard in late 2018. This standard was approved by Aurora Energy's Board in November 2018, who also defined the risk appetite for the business, as depicted in Figure 24, below.

Figure 24: Risk matrix

Likelihood \ Impact	Insignificant	Minor	Moderate	Major	Catastrophic
Almost certain	Low	Medium	High	Extreme	Extreme
Likely	Low	Low	Medium	High	Extreme
Possible	Insignificant	Low	Medium	High	High
Unlikely	Insignificant	Insignificant	Low	Medium	High
Rare	Insignificant	Insignificant	Low	Medium	Medium

Intolerable Risks

226. The RCM standard is flexible, and recognises that the nature of our activities means we will have some risks that require tailored analysis, and some can utilise more generic analysis. This, the RCM standard allows for qualitative or quantitative analysis, as appropriate, depending on the context. In practice, this means that we have different risk assessment methods depending on the context of the risk.

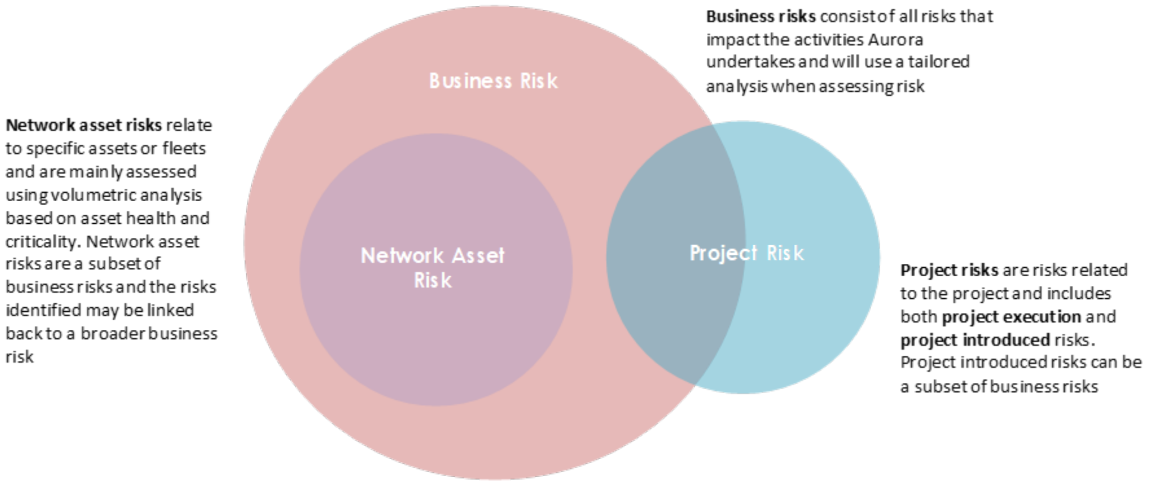
227. We use three broad risk contexts ,as depicted in Figure 25:

- Business risks (sometimes referred to as operational risks);

[18] ISO 31000:2018. Risk management – Principles and guidelines

- Network asset risks (sometimes referred to as fleet risks); and
- Project risks (sometimes referred to as delivery risks).

Figure 25: Risk categories



228. The RCM standard outlines the approach to assessing risk. Risk impact (consequence) and likelihood (probability) are assessed within a 5 by 5 matrix to determine a risk rating. The business uses five impact categories (financial, operational, reputational, regulatory and legal, and HSE) with the highest rating in any category being the overall rating.

229. Three risk ratings are determined as part of assessing and evaluating the risk:

- Initial risk rating. This is the inherent risk rating, without any mitigation controls applied;
- Current residual risk rating. This is the current state of the risk, in light of the existing mitigation controls applied; and
- Target residual risk rating. This is risk rating when we are satisfied that appropriate mitigation controls have been applied and the treatment plan is effective.

Figure 26: Risk rating categories

B.5.2. Network Asset Risk Management - Background

230. The application of risk or criticality-based asset management tends to vary across the New Zealand distribution sector; however, the approach is becoming increasingly important as assets built in the 1960s and 1970s approach end-of-life, requiring an uplift in asset renewals. This is particularly relevant for Aurora Energy, as we have a backlog of renewals that need to be prioritised.

231. The identification, management and tracking of our network asset risks is constrained by our systems, processes, and data completeness; however, we have commenced work focused on remedying this. We are actively addressing asset specific risks, identified by WSP in its 2018 independent review report, and we are actively responding to risks identified through our asset inspection and condition assessment maintenance work; e.g., defects and pole testing.

232. Due to relatively low levels of asset health, we are dealing with elevated probabilities of asset failure. This impacts a number of high consequence assets and/or asset fleets within the network. Reflecting this condition, we have included the general risk 'failure of assets' in our risk register, and noted that risk as having the potential to be above the tolerable risk level.

233. A major component of our treatment plan for asset failure risk is our response to the WSP risk review, as set out in our WSP Action Plan. Until we can identify and quantify the assets at risk, our progress in treating these risks will be strongly linked to delivery of the WSP Action Plan.

B.5.3. Network Asset Risk Management - Objectives

234. Our asset management planning seeks to reduce the level of network asset risk to below our risk tolerance line as quickly as reasonably practical, taking account of deliverability constraints and cost implications for our customers.

235. To achieve this, we have taken immediate action to increase our capability and improve our underlying systems. We must also ensure we have sufficient resources (including financial) available to ensure that our plan is deliverable, and our business is sustainable; therefore, our focus is on three high level objectives:

- Develop and implement short term remediation plans for identified high risk assets – this comprises our action plan addressing high-risk assets identified by WSP, and other Aurora Energy identified short-term, high-risk assets;
- Ensure that this CPP proposal establishes the prudent quantity of high-risk assets that will need risk mitigation in the CPP period, noting that quantification for volumetric fleets does not require asset identification in many cases; and
- Develop systems and approaches that provide rich asset information and support risk evaluation, to ensure that our investment planning and works delivery provides prudent and efficient levels of risk reduction.

236. Good practice risk management establishes relationships between fleet failure modes and associated consequences. To manage and track risk reduction (instead of asset health), it is important that we establish this relationship.

237. For volumetric fleets, we have not been able to show how the asset health of each individual asset links to the probability of different failure modes and associated consequences, but we do know which fleets have inherently high risk. However, to forecast medium-term replacement volumes, it is not always necessary to establish a failure/consequence relationship because not all the replacement drivers are associated with intolerable risk – there is also cost-effective renewal (e.g.,

synergies with other works) and efficient operational management of the fleet to consider; e.g., some assets can be run to failure.

238. Volumetric analysis is used for smaller value, higher-volume works that are reasonably routine and uniform. The analysis is generally asset fleet-based, and assesses multiple assets to forecast future renewal volumes.

B.5.4. Our Approach to Managing Network Asset Risk

239. Volumetric analysis reflects the two main determinants of risk (likelihood and consequence) by using asset health and asset criticality as simplified proxies:

- Asset health: defines Asset Health Indices (AHI), measured in years, that reflect the 'remaining life' of assets. This represents the estimated time before an intervention may be required in response to increasing risk of failure, and is used as a proxy for likelihood of asset failure.
- Criticality: recognises that assets have differing failure consequences depending, for example, on their physical location and their electrical connection point. We use criticality as a proxy for consequence of asset failure.

Table 8: Asset health indices

AH Score	Category Description	Replacement Period
H1	Asset has reached the end of its useful life.	Within one year
H2	Material failure risk, short-term replacement	Between 1 and 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
H4	Normal deterioration, monitor regularly	Between 10 and 20 years
H5	As new condition, insignificant failure risk	Over 20 years

240. Network asset failure risk is managed through the following mechanisms:

- Developing a forecast for each fleet reflecting long-term projections of renewal need; and
- Delivering programmes of work directly informed by observed risks on the network.

241. Depending on the fleet, we may have different approaches to forecasting and delivery. Descriptions of the different approaches are as follows:

Table 9: Contrasting risk management approaches applicable to forecasting and delivery

Forecasting (planning) approach	Delivery approach
1 Volumetric – is used for smaller, higher volume of works that are routine and uniform. It does not identify specific assets to be replaced but rather volumes of required remediations	1 Condition – assets are tested or visually inspected. Test results are assessed, and interventions issued and prioritised by criticality if relevant.
2 Scheduled – is used for large projects that have well defined scopes and timings. These identify specific assets and solutions to meet specific site requirements. Scheduled projects are generally prioritised by criticality or cost benefit analysis for growth related projects	2 Reactive – assets are reactively replaced as part of fault response. This work is generally dispatched by the control room or standby controller.
3 Targeted – is used for specific programmes of work typically addressing type issues or defects. These are generally semi-identified, where specific assets may be identified in data sources however the forecasts d not identify them on an annual basis	3 Proactive – assets are scoped to be replaced using simple triggers, such as expected life. This is generally used for asset types that have demonstrated age-related failure modes however no reliable testing methodology has been developed. Depending on the fleet, proactive replacements are prioritised by criticality.
	4 Hybrid – Combination of the Reactive and Proactive approaches (2 and 3)
	5 Scheduled – project manager and lead engineer further refine scope, undertake detailed design, tendering and follow through on construction.

242. Table 10 outlines, at a high level, the different risk management approaches that we use for each portfolio:

- The first step is to determine the potential (inherent) risk of all or part of a fleet due to high consequence of failure. This inherent risk informs our approach to intervention.
- If a fleet has an inherently low consequence (e.g., underground LV) then we forecast renewal based on a maximum practical life, with actual renewal undertaken reactively on failure. or proactively with other works.

Table 10: Risk management approach – selected asset fleet intervention strategies

Fleet	Inherent Risk	Main Forecasting Approaches and Modelling	Main Delivery Methods
Poles	High	Volumetric Survivor curve	Condition, criticality based bundling
Crossarms	Medium/High	Volumetric REPEX	Condition, criticality based bundling
Subtransmission conductors	High	Scheduled / volumetric	Scheduled / Proactive
Distribution conductors	High	Volumetric REPEX	Proactive
Low voltage conductors	High	Volumetric REPEX	Proactive
Subtransmission cables	Low/Medium	Scheduled	Scheduled
Distribution cables	Low	Volumetric REPEX	Hybrid Criticality based bundling
Low voltage cables	Low	Volumetric REPEX	Hybrid
Power transformers	Medium/High	Scheduled Risk-based	Scheduled
Buildings and grounds	Low/Medium	Scheduled	Scheduled
Indoor switchgear	High	Scheduled Risk-based	Scheduled
Outdoor switchgear	Medium	Scheduled	Scheduled
Ancillary zone sub. equipment	Low/Medium	Scheduled	Scheduled
Ground-mounted switchgear	Medium	Volumetric REPEX	Condition / Proactive
Pole-mounted fuses	Low	Volumetric REPEX	Proactive / Reactive
Pole-mounted switches	Low	Volumetric REPEX	Condition / Proactive
Low voltage enclosures	Medium	Volumetric REPEX	Condition / Proactive / Reactive
Ancillary dist. sub. equipment	Low	Targeted Type-based	Condition / Proactive
Ground-mounted distribution transformers	Medium	Volumetric REPEX	Condition
Pole-mounted distribution transformers	Medium	Volumetric REPEX	Condition

Fleet	Inherent Risk	Main Forecasting Approaches and Modelling	Main Delivery Methods
Protection	High	Targeted Type-based	Proactive
Batteries and DC systems	High	Targeted Type-based	Proactive
Remote terminal units	Medium/High	Targeted Type-based	Proactive

Box 1: Ownership, governance and risk management summary

Aurora Energy has robust governance and management practices underpinning and controlling its business activities, supported by a developing risk management approach based on and international framework.

Aurora Energy's Board of Directors, through its CPP Governance Committee, has had significant oversight of the development of our CPP, and has reviewed, challenged and approved key elements of our proposal at appropriate milestones.

Appendix C. Consultation and Verification

243. Two important aspects of developing our CPP proposal involve consumer consultation and independent verification.

244. Consumer consultation on our CPP proposal, while a regulatory requirement, is considered good electricity industry practice that assists consumers to provide input into network development and investment decisions, and helps to shape the dimensions, including cost, of the services that we provide.

245. Independent verification involves the engagement of a suitably qualified and experienced person or organisation, independent from Aurora Energy, to assess the extent to which our CPP proposal meets the statutory expenditure objective.[19]

246. This appendix summarises our consumer consultation activities, the independent verification process, and concludes with a description of how our CPP proposal has been influenced by, and responded to, consumer feedback and the independent verifier's report.

247. This chapter is supplemented by our separate Consultation Report, and the independent verifier's Report; both of which form part of our CPP Application.

C.1. Consumer Consultation

248. Customer consultation is a regulatory requirement of a CPP proposal to ensure that the applicant's plans reflect customers' priorities and that our service reflects their preferences. We thank customers for their time and generosity in contributing their views on our future investment plans and preferences on what services they expect from us.

C.1.1. Context for Consultation

249. Before we decided to apply for a CPP, the regulator and the community had raised concerns about network safety, particularly the condition of poles. With urgent action needed across our network, from 2017 on we invested significantly in corrective actions to rectify renewal shortfalls. Unlike previous CPP applicants, we had materially increased network investment ahead of an increase in allowable revenue under a CPP.

250. Previous reviews by the regulator, shareholder and an independent engineering review by WSP in 2018 made it clear that there were a number of fleets where increased safety-driven renewal investment was essential. Community leaders and individual customers were unequivocal that asset failures were an unacceptable outcome of deferred renewal and maintenance.

[19] The expenditure objective is defined in the IMs "Expenditure objective means objective that capital and operating expenditure reflect the efficient costs that a prudent non-exempt EDB 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.".

251. Going into consultation, we had some scope to modify our draft proposal before submitting our CPP application to the Commission. Equally, the scope for change was limited by the safety-driven renewal investments that simply had to be done to meet minimum safety requirements and customers' expectations around community safety and service adequacy.

C.1.2. Consultation - What we did and why

252. From previous energy sector consultations and our own experience and research, we understood that any CPP consultation would face challenges due to low levels of public awareness and engagement. To overcome these barriers to effective public participation, we took a phased approach to consultation, first building awareness before consulting on specific plans. We also established customer panels to connect us directly to customers and consumer experts and gave those participants the opportunity to influence our proposals informed by a fundamental basis of knowledge.

Figure 27: Engagement process

253. Our consultation used deliberative engagement techniques, interactive online engagement and customer research. We provided multiple feedback channels to suit a range of customer preferences from customer panels, one-on-one meetings, stakeholder briefings, online engagement, video explainers and drop in sessions to customer surveys and in-depth research.

Figure 28: Key consultation metrics

CONSULTATION WEBSITE

4,405
Visits to online engagement site

192
Registrations on engagement site

66
Online submissions

CUSTOMER ADVISORY PANEL

15
Members participated in Customer Advisory Panel

233
Session hours over 5 meetings

INDEPENDENT CAP REPORT

1
Independent report from Customer Advisory Panel

ONE-ON-ONE MEETINGS

19
Stakeholder meetings with councils, retailers, sector organisations

7
Drop in sessions

CONSULTATION DOCUMENT

539
Downloads of consultation document

271
Downloads of consultation summary

12
Locations where consultation document available

93
Submissions
- 66 online and 27 other

CUSTOMER VOICE PANELS

23
Participants in Customer Voice Panel focus group meetings

3
Locations: Dunedin, Cromwell, Queenstown

199
Session hours over 18 face-to-face meetings

AWARENESS

125,000
Reach across social media channels

4,185
Online videos watched

110,000
Regional newspaper circulation

53
News media items

CUSTOMER RESEARCH

1,000 + 100
Residential + business customers survey on electricity use and preferences (Aug 2019)

9
Depth interviews with a range of customer types (Sep 2019)

500 + 100
Residential + business customers
Survey on our proposal and alternatives (Feb 2020)

DIRECT COMMUNICATION

4 Email newsletters to stakeholders

LOCATION OF REGISTERED WEBSITE USERS

39% Central Otago and Wanaka

38% Dunedin

14% Queenstown

10% Other New Zealand

C.1.3. What we Heard

254. What we heard from customers was an understanding and desire for essential work to be done, but that the impact of the proposed pricing increase was a major concern for affordability, particularly for vulnerable customers. Most respondents were satisfied with the current level of reliability they experienced and there was little appetite for improving reliability if prices were to go up. Some aspects of customer service were expected and valued highly, namely communication about planned and unexpected power outages and the new connections process.

Figure 29: Key themes in response to our consultation document

The need for essential work was accepted

- You generally accepted the need for essential work, especially for safety reasons
- You also agreed that investment needed to be made to renew the existing network and prepare for the future

“WHILE I APPRECIATE WE NEED UPGRADES, THIS SHOULD NOT BE A COST TO THE CONSUMER IN SUCH A SHORT PERIOD OF TIME”

- The Advisory Panel supported “Our proposed plan” and rejected Accelerated and Enhanced alternatives based on sudden and large increases in customer prices

Price increases were unwelcome

- You felt the size of the proposed price increases was unexpected and unwelcome with widespread concern, especially the impact on vulnerable households
- Many of you suggested our owner should pay for deferred maintenance and not consumers

“POWER IS ALREADY HIGH ENOUGH WITHOUT ADDING TO THE LINE CHARGE”

- You said you wanted us to do something to help vulnerable customers with the impact of price increases

Little appetite for improving reliability if prices go up

- Nearly 9 out of 10 households said they were satisfied with their current level of unplanned power cuts (unplanned reliability)
- Only a very few (8%) wanted better reliability if this meant paying more

“I WILL BE HAPPY TO RETAIN EXISTING RELIABILITY AND MINIMISE THE INCREASE”

- The Advisory Panel wanted us to defer Option A: “Improved reliability for worst-served customers” to later periods and consider it alongside other initiatives to improve reliability

C.1.4. Independent Verification of Consultation

255. An important part of the Commission’s CPP framework is having an independent expert, known as the independent verifier, peer review our submission before we make our application. Having reviewed our consultation, the independent verifier concluded that we had undertaken substantial consumer consultation in preparing our CPP application and had prepared and made available significant material, consistent with the regulatory requirements. Much of our consultation was in line with best industry practice in New Zealand and other jurisdictions, such as Australia.

C.1.5. Commerce Commission Consultation

256. As noted in Chapter 1, the Commission will conduct its own customer and stakeholder consultation on our proposal as part of its review process, and has indicated that this is likely to occur in November-December 2020.

257. Our customers and stakeholders will therefore have a further opportunity to provide feedback on our future plans by participating in the Commission’s own review process. More information on how

to get involved will be provided on the Commission's website www.comcom.govt.nz and our consultation website www.yoursay.auroraenergy.co.nz.

258. We encourage our customers and stakeholders to engage with the Commission's process.

C.2. Independent Verification of our CPP proposal

259. An important aspect of the Commission's CPP framework is the use of pre-submission verification by an independent expert (the verifier). At a high level, the verification process is intended to add value to the quality of CPP proposals and to the Commission's decision making by testing, in advance of submission, the assumptions underpinning forecast information capital expenditure, operating expenditure, and intended quality standards. One of the key roles of the verifier is to select projects or programmes of work for detailed assessment.

260. An overriding duty for the verifier is to assist the Commission as an independent expert on relevant matters within the verifier's area of technical expertise. We have the opportunity to revise our CPP proposal to address or respond to matters raised in the verifier's report before lodging our submission to the Commission. Whilst the Commission will undertake its own assessment of our CPP proposal, it can avoid duplication of effort by relying on the professional opinion expressed by the verifier.

261. The verifier's roles and responsibilities under the IMs include:

- engaging with the CPP applicant in an independent manner in accordance with its Terms of Reference;
- assessing the extent to which the CPP applicant's policies allow it to provide services on an efficient basis and that meet the general needs and expectations of customers;
- assessing the extent to which the CPP applicant's policies have been implemented;
- prior to the Commission's assessment of the CPP proposal, assessing whether the CPP applicant has provided complete and sufficient information in its intended CPP proposal;
- prior to the Commission's assessment of the CPP proposal, providing an opinion to the CPP applicant on whether its Capex forecasts and Opex forecasts meet the expenditure objective;
- providing an opinion to the CPP applicant on the reasonableness of its key assumptions and policies for its forecast information;
- 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 customers; and
- providing a list of the key issues which it considers the Commission should focus on when assessing the CPP proposal.

C.2.1. Engaging the Verifier

262. Following a 'registrations of interest' (ROI) and 'request for proposal' (RFP) process, we proposed to the Commission that Farrierswier Consulting Pty Ltd (Farrierswier) be appointed as the independent verifier, with GHD Pty Ltd supporting Farrierswier in a subcontracted capacity. In making that

proposal, we noted that Farrierswier's experience in verifying Powerco's 2017 CPP proposal demonstrated their suitability for verifying our CPP proposal. Similarly, GHD's involvement in verifying Transpower's 2019 IPP proposal evidenced their suitability to act in a subcontracted capacity.

263. The Commission duly accepted the appointment of Farrierswier as the independent verifier of our CPP proposal. We subsequently entered into a Tripartite Deed with Farrierswier and the Commission, which sets out the obligations and responsibilities of each respective party during the CPP process.

264. Table 11, below, shows the key steps in engaging the independent verifier:

Table 11: Engaging the verifier

Activity	Date
Registrations of interest called	18 Sep 2017
Requests for proposal called	5 Feb 2019
Recommendation to appoint Farrierswier made to Commission	5 Apr 2019
Commission approval of Farrierswier	8 May 2019
Farrierswier appointed and tripartite deed executed	19 Jun 2019

C.2.2. Verification Process

265. The conduct of verification is defined in schedule G of the IMs – terms of reference for verifiers. In practical terms, the process of independent verification requires a comprehensive exchange of information and evidence with the independent verifier. We highlight the key activities associated with independent verification, below:

- We conducted an introductory meeting with the verifier and the Commission on 3 July 2019. This formally initiated the process of independent verification. The meeting was preceded by two days of familiarisation with the nature of the Aurora Energy network, involving a series of site visits in Central Otago and Dunedin.
- The Tripartite Deed governing verification, executed by Aurora Energy, the Commission and the independent verifier, provided for monthly meetings to be held to discuss matters pertinent to verification. We commenced these meetings in September 2019.
- We provided the independent verifier with several tranches of information relevant to our CPP proposal. That information ranged from broad, publicly available information like WSP's independent review of the network and our subsequent Action Plan, to very specific and detailed information on our investment proposal and proposed quality standards. We also provided a significant amount of information on how we operate our business, including controlled documents, standards and guidelines.
- The independent verifier advised us, on 20 October 2019, of identified programmes and projects it had selected, in accordance with IM clause G4.

- We responded to over 450 questions from the independent verifier on our draft proposal and we provided over 700 documents and spreadsheets.
- We held workshops with the independent verifier, substantially over the period 16 to 20 March 2020, to clarify aspects of our CPP proposal and to clarify answers to questions asked by the independent verifier. Due to the impact of Covid-19, and the restrictions on international travel, workshops were held by videoconference.
- We received the draft independent verifier's report on 6 April 2020, and held further workshops with the independent verifier to clarify and understand its draft findings. We subsequently considered the findings of the independent verifier's draft report, and in response made a number of changes to our proposal.
- We received the independent verifier's final report, for submission with our CPP Application, on 8 June 2020.

C.2.3. Independent Verifier's Report

266. The independent verifier has laid out it findings in a comprehensive report, which accompanies and forms part of this CPP Application.

267. The verifier has been able to verify that all but a very small proportion of the proposed expenditure that it examined meets the expenditure objective. Consistent with the approach, set out in the IMs, of examining identified programmes and projects in detail, approximately 24 percent of our proposed expenditure was not reviewed by the verifier.

268. 1 percent of our total expenditure remains unverified, and the Commission has been guided by the verifier to consider the underlying issues giving rise to non-verification as it conducts its assessment of our CPP proposal.

269. 2 percent of our total expenditure has been categorised as 'contingent' by the verifier, in the wake of emerging Covid-19 effects. This is consistent with moderations we have made in response to Covid-19, and we have discussed issues surrounding contingent projects and programmes in section 1.3.5, above.

270. The verifier has identified that the programme of works we proposing over the CPP period should be deliverable and has noted that, where there are delivery risks, these have been identified and a delivery plan is being advanced.

271. In engaging with our customers on our CPP proposal, the verifier has found that we have conducted a substantial consultation process, and that much of the consultation we have undertaken is consistent with industry best practice prevailing in New Zealand and Australia.

C.3. Changes as a Result of Customer Feedback and the Independent Verifier's Report

272. Following customer feedback during consultation and the views of the independent verifier, we made a series of moderations and changes to our draft CPP proposal before finalising it for submission.

273. The global response to the Covid-19 pandemic was developing during finalisation of our application. In addition to changes from customer and verifier feedback, we made some precautionary changes in response to the expected impacts of the Covid-19 pandemic on economic activity and regional electricity demand.

C.3.1. How customer feedback shaped our draft CPP proposal

274. As a result of customer feedback we made the following moderations and changes to our draft proposal.

Table 12: Adjustments to our CPP proposal following consultation and receipt of the draft independent verifier's report

Customers told us....	In response, we have....
Increased investment is supported	Adopted 'Our proposed plan' rather than the 'Accelerated' or 'Enhanced' alternatives. This position is consistent with the feedback received that essential work is supported, but affordability is a significant concern.
Existing levels of reliability are acceptable	Targeted our investment plans to improve network safety and asset health (noting there will be consequential improvements in unplanned reliability).
Magnitude of price increase raises concerns	Targeted our investment plans to improve network safety and asset health (noting there will be consequential improvements in unplanned reliability).
Asset degradation should be avoided in future	Committed to improve our approach to asset management, which should ensure that the historical degradation of assets is not repeated in future.
Regional price differences raised concerns	Accepted that our pricing regions and cost allocations should be reviewed, and we will explain to consumers how prices are derived and the relative differences are fair and equitable.

Customers told us….	In response, we have….
Some customer services are expected as fundamental, but affordability is a primary concern	Excluded the 'Improved customer service' option, but retained investment in priority customer service initiatives and ongoing improvement during 3-year CPP period. Priorities identified by customers were improved outage information (e.g. real time updates for unplanned outages) and the new connections process.
Regional price differences raised concerns	Accepted that our pricing regions and cost allocations should be reviewed, and we will explain to consumers how prices are derived and the relative differences are fair and equitable.
Some customer services are expected as fundamental, but affordability is a primary concern	Excluded the 'Improved customer service' option, but retained investment in priority customer service initiatives and ongoing improvement during 3-year CPP period. Priorities identified by customers were improved outage information (e.g. real time updates for unplanned outages) and the new connections process.
Readiness for a low carbon future is valued by some customers, but affordability is a primary concern	Excluded the 'Improved future technology readiness' option, but retained sufficient investment during 3-year CPP period to remain prepared for technology change. Developed a Network Evolution Roadmap to support the network's transition to a low-carbon future and uptake of distributed energy resources.
Adopted a non-network solution for forecast network constraints in the Upper Clutha area at a lower lifetime cost. Under the solution, a contracted partner will provide Distributed Energy Resources (DERs) through the installation of solar panels and battery storage in customers' homes or small businesses.	

275. In order to mitigate the impact of price increases, we have begun a number of initiatives, including:

- continue to lobby central government for quality breach fines to be reinvested in community to benefit consumers;
- advocate for establishing a regional energy efficiency fund for vulnerable households in collaboration with local Councils; and
- maintain tight control on new recruitment while ensuring we have the necessary capability to complete essential work.

C.3.2. How independent verification shaped our draft CPP proposal

276. Following independent verification, and consistent with the above views expressed by customers, we made the following further adjustments to our expenditure plans:

- we applied a series of efficiency adjustments to our spend plans. These are based on a range of expected efficiency sources. Over time these will lead to material reductions in costs (approximately $5 million over 5 years). In the short-term, we expect the scope for material efficiency gains to be limited due to external factors, and until our planning and delivery maturity further improves;
- we have deferred a number of non-critical renewal and growth projects, particularly those with a reliability driver, to later in the CPP period;
- we have reduced future staffing costs to reflect likely productivity gains; and
- we have made a series of reductions in reactive and corrective maintenance to reflect potential improvements in overall asset condition and health.

C.3.3. The Impact of the Covid-19 Pandemic

277. After our consultation concluded in late January 2019, New Zealand and the world responded to the Covid-19 pandemic. The long term implications are still emerging as this application is being finalised, but are expected to affect the community and the local economy, with the hospitality and tourism sectors especially hard hit.

278. As an initial response, we have tried to reduce the price increase as far as possible and revised our growth-related investments in our final proposal. Steps we have taken include:

- removed or deferred major growth projects to better match the need of reduced demand, these were the Arrowtown-Frankton high voltage supply ring upgrade, Arrowtown 33kV switchgear and the new Omakau zone substation. We have also deferred a resilience project to install a new 33kV cable between our Smith St and Willowbank zone substations
- reduced our consumer connections forecast to reflect a likely reduction in connection applications
- deferred distribution reinforcement works to reflect reduced constraints on the network due to expected lower growth.

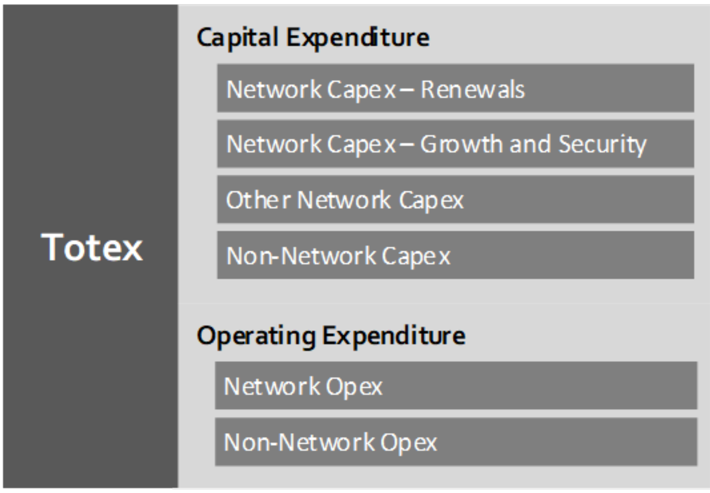
Appendix D. Expenditure Summary

279. This Appendix explains how we categorise our expenditure, before setting out total proposed expenditure over the CPP Period.

D.1. Our Expenditure Categories

280. The figure below sets out our expenditure categories, which are based on our current internal categories. Each expenditure category is made up of several expenditure portfolios. These portfolios form the basis of our internal expenditure governance and budget management.

Figure 30: Expenditure categories



Box 2: Explanation of the expenditure charts used in this document

The expenditure charts in this document depict three time periods:

- historical spend: from RY15 to FY19 inclusive (light grey columns) based on actual, disclosed expenditure.
- current period: the dark grey columns reflect actual expenditure in RY20 (not yet disclosed) and budgeted RY21 expenditure.
- CPP spend: forecast expenditure from RY22 to RY26 inclusive (orange columns). We are proposing a three year CPP period and have highlighted this using a darker shade.

D.2. Expenditure Amounts

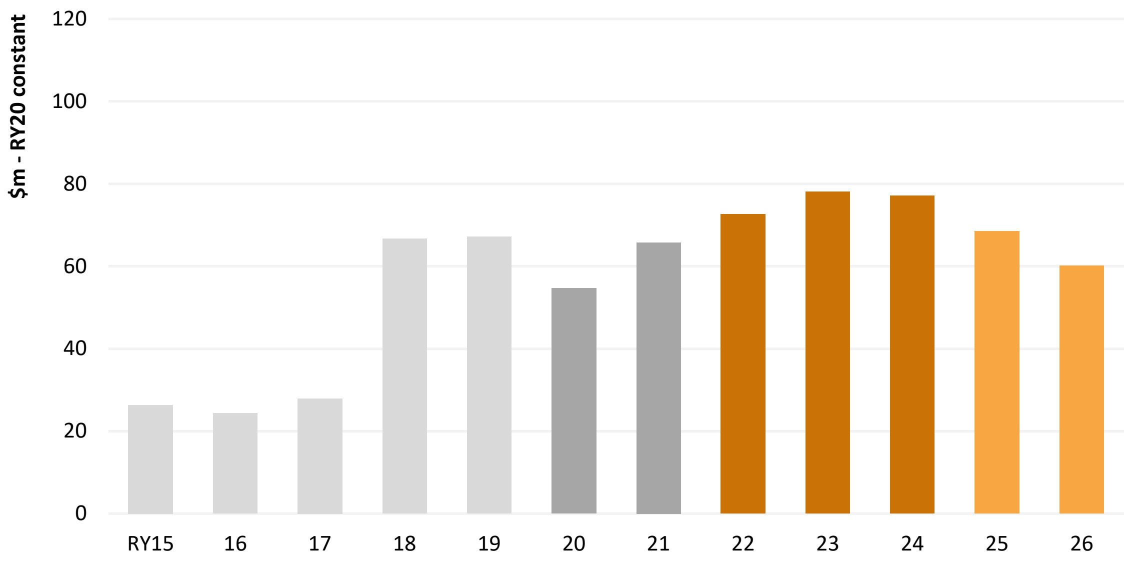
281. When presenting expenditure amounts in our proposal, we have adopted several conventions.[20] All amounts (unless stated otherwise) are presented:

- in constant value terms using RY20 dollars
- post internal cost capitalisation procedure
- net of capital contributions
- by regulatory year, e.g. RY20 refers to 1 April 2019 to 31 March 2020.

D.3. Total Capex

282. Figure 31, below, sets out our proposed total Capex for the CPP Period and equivalent historical spend.

Figure 31: Total historical and forecast Capex[21]



283. During the CPP Period we plan to invest $227.7m in new assets to deliver and support our electricity distribution service. This is a 21% increase above the previous latest three-year period (RY18 to RY21).

20 The expenditure schedules provided in Appendix O include technical accounting adjustments, and don't include the impact of capital contributions, and therefore appear higher than Aurora's actual spend.

21 The reduction in Capex in RY20 is caused by a range of factors largely outside of Aurora Energy's control affecting some larger projects, rather than any particular deliverability issue. These have included; deferral of projects associated with Transpower 33kV switchboard delays at the Halfway Bush GXP, and amended plans the Dunedin Hospital where we diverted planning and engineering resources to the (now un-needed) relocation of North City Zone substation.

284. Points to note in relation to this expenditure profile:

- **Historical investments:** as described in section 1.2, above, our historical levels of investment were low. The uplift depicted in RY18 coincides with the introduction of the fast track pole programme and our separation from Delta.
- **Renewals:** we need to maintain elevated levels of investment to manage the health and safety risk levels on our network. This is necessary if we are to continue to provide a safe and reliable service to customers. Appendix E sets out and explains these investments by portfolio.
- **Growth and security:** investments enable us to support regional growth and ensure we can connect new customers. We expect the impact of Covid-19 to supress demand at the beginning of the CPP Period, however from RY23 we expect to begin to ramp up these investments again to enable us to support regional growth and to ensure we can connect new customers. See Appendix F.
- **Non-network Capex:** capital investments in IT capability and systems will reduce over the period as we shift more of our solutions towards SaaS (software as a solution). See Appendix J.

D.3.1. Summary of Moderations

285. In developing our CPP Capex forecasts we have used a robust governance and challenge process (see Appendix B). This process has included feedback from consultation engagements, reflected feedback from the independent verification process, and taken into account potential Covid-19 impacts. Specific examples include:

- Consultation feedback: in response to stakeholder views, in particular the lack of appetite for improved reliability if this requires an increase in prices, we have removed a number of reliability-driven projects. This included an optional work programme to improve underlying performance on our worst performing feeders.
- Risk/performance trade-offs: while maintaining our focus on safety driven programs, we have deferred a number of non-critical renewal investments.
- Verifier feedback: to address independent verifier feedback, we have made adjustments to two renewal programmes. These include efficiency adjustments that reflect scope for potential efficiency gains from asset management improvements, increased competition amongst our service providers, and better works delivery processes. See Box 3 for a description of these efficiency adjustments.
- Growth and security: in light of expected demand decreases due to Covid-19, we have deferred a number of capacity-driven investments by at least two years. Toward the end of the CPP period we expect to begin to ramp up these investments to enable us to support the return of regional growth and to ensure we can connect new customers. Discussed in Appendix F.

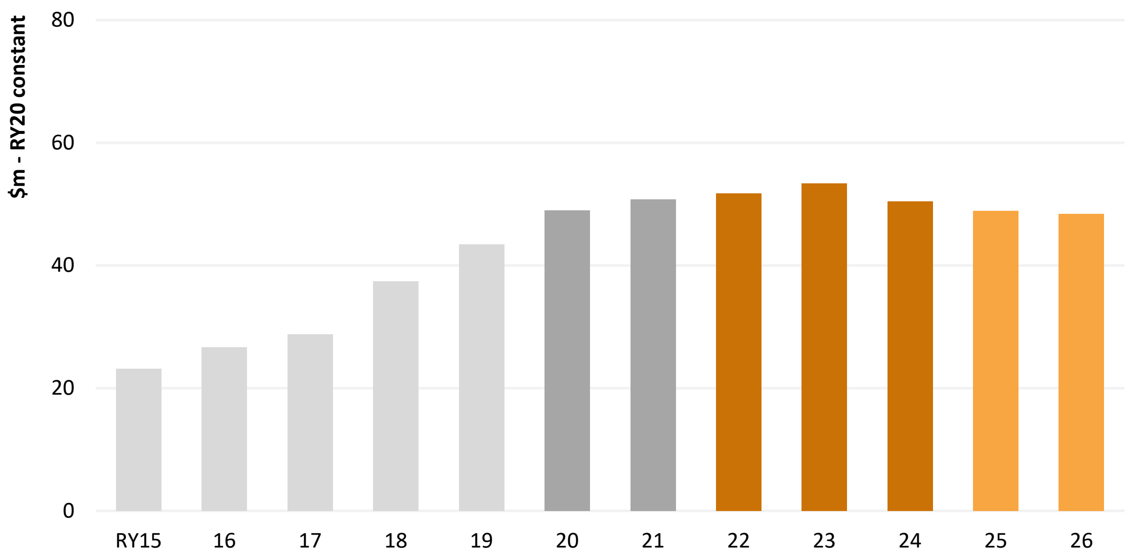
- Other network Capex: due to the impact of Covid-19 we have reduced short-term investment levels in new connections. While acknowledging the overall uncertainty, we expect growth-driven activity from RY23 onward to return to levels broadly in line with recent years. See Appendix G.

286. Appendix E to Appendix G set out proposed Capex Investments over the CPP period in detail.

D.4. Total Opex

287. The figure below sets out our proposed total Opex for the CPP Period and equivalent historical spend.

Figure 32: Total historical and forecast Opex



288. During the CPP Period we plan to spend $155.6m on activities that support the electricity services we deliver to customers. This is a 20% increase above the previous three-year period (RY18-RY20).

289. Points to note in relation to this expenditure profile:

- **Maintenance:** activity is increasing as we take action to reduce our defect backlogs and improve our inspection and condition regimes. Improved asset information from the expansion of our inspection regime will help optimise future investments.
- **Vegetation management:** expenditure will reduce over time as roll out our new proactive, cyclical approach. This move from a largely reactive approach to good practice will, over time, lead to improved safety and reliability outcomes and ensure full compliance with the Tree Regulations.
- **Improving capability and capacity:** while the business has made significant improvements to our asset management capability and our ability to efficiently deliver our work programmes, we recognise we need to make further progress. To do so, we will recruit further specialised staff and undertake improvement initiatives such as our ISO 55000 programme.

- **Historical Opex:** historical Opex was suppressed due to the service arrangements in place with our sibling company Delta. The uplift in RY18 (depicted above) coincides with the establishment of Aurora Energy as a standalone business.

D.4.1. Summary of Moderations

290. In developing our CPP Opex forecasts we have used a robust governance and challenge process (see Appendix B). This process included feedback from consultation, reflected feedback from the independent verification process, and took into account potential efficiencies. Specific examples include:

- efficiency adjustments: to address independent verifier feedback, we have made adjustments that reflect the scope for potential efficiency gains from asset management improvements, increased competition amongst our service providers, and better works delivery processes. See Box 3 for a description
- refined forecasts: we have adjusted several forecasts including deferring some initiatives to reduce the overall step up in expenditure
- Capex/Opex trade-offs: we have reduced future maintenance expenditure in the expectation that our renewals programme will begin to improve the overall condition of our asset fleets. Improved condition should result in fewer faults and less corrective maintenance.

D.5. How we Forecast Expenditure

291. Our CPP expenditure forecasts were developed using predictive forecasting techniques. These ‘bottom-up’ approaches used cost estimates and unit rates linked to outturn costs (where available).

D.5.1. Overview

292. Generally, the forecasting methodology used for a particular portfolio is based on the type of expenditure, for example whether it is for large capital projects, ongoing programmes or expensed activities. This approach has been used to ensure our forecasts are robust, transparent, and repeatable.

293. Good practice cost estimation utilises a range of qualitative and quantitative methods to establish the most likely expenditure at project or programme level depending on the nature of the work. Our forecasts for works beyond two years into the future use a combination of the following approaches:

- **Tailored estimates (Capex):** used for large single projects (>$500k) that require individual tailored investigation. These are often supported by independent external cost estimates
- **Volumetric forecasts (Capex and Opex):** used for smaller, high-volume works that are reasonably routine and uniform. These include scheduled repairs, small renewals, and scheduled maintenance
- **Trend-based forecasts (Capex and Opex):** are mainly used for forecasting our medium-term Opex requirements, both network and non-network. They are also used for certain Capex forecasts e.g. consumer connections.

294. These estimate types are discussed below.

D.5.2. Tailored Estimates

295. This approach involves developing cost estimates based on project scopes. These scopes are determined from desktop reviews of asset information such as aerial photographs, site layout drawings, underground services drawings, and available ducting. An estimate is built up based on the scope and a set of 'building-block' rates from our price-book. These assessments provide reasonably accurate estimates for materials and work quantities, for example, building extensions and cabling.

296. Building-block costs are developed based on a range of sources including historical outturns, service provider rates, quotes, and external reviews. They reflect material costs determined with reference to supply contracts and historical costs. Installation costs are informed by similar previous projects and are updated over time with current prices or quotes.

297. For investment in large non-network systems, we have based our forecasts on a combination of vendor responses and desktop estimates. The desktop estimates are mainly informed by historical implementations and discussions with vendors.

298. As part of our AMDP programme we will introduce a risk-based estimation approach for large projects that involves assessing and pricing project risks. Over time we will report on the expected risks, identifying whether they eventuated, to what extent, and whether the risk funding was adequate. Feedback of this information will enable our planning team to better include risk in future forecasts.

299. More detail on the type of estimation approaches used for particular fleets and portfolios is included in later sections and is also discussed in our 2020 AMP.

D.5.3. Volumetric Forecasts

300. We categorise programmes with large volumes of similar works as volumetric for estimation purposes. A key input for determining appropriate unit rates for volumetric projects is the availability of historical costs from completed equivalent projects. Where available we have used this feedback to derive average unit rates to be applied to future work volumes. The resulting unit rates are often combined to form building block costs that include the main components of typical works.

301. Using this approach we consider that estimates for our volumetric works will be appropriate, given the following assumptions:

- project scope is reasonably consistent and well defined
- unit rates based on historical outturns effectively capture the impact of past risks and that the aggregate impact of these risks across portfolios is unlikely to vary materially over time
- a large number of future projects are likely to be undertaken, so that the net impact of variances will tend to diminish given a large number of projects
- the volume of historical works is sufficiently large to provide a representative average cost.

302. For investment in non-network assets and systems (e.g. IT hardware) we have used expected volumes and unit rates informed by a number of factors including discussions with vendors and historical outturns.

303. More detail on the type of estimation approaches used for volumetric fleets and portfolios is included in later sections and is also discussed in our 2020 AMP.

D.5.4. Trend-based Forecasts

304. We have used a trend-based approach to forecast parts of our expenditure. This is mainly used for certain trend-based Capex forecasts such as asset relocations. (Note these are distinct from our base-step-trend forecasts discussed below).

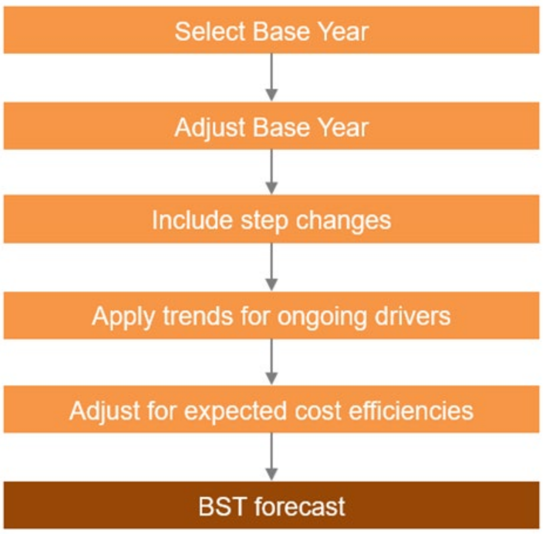
305. The approach starts with selecting a representative year (or average of multiple years). The aim is to identify a period that is representative of recurring expenditure we expect in future years. If there are significant non-recurring items, an adjustment is made to remove their impact.

306. Expenditure in this typical year is then projected forward. To produce our forecasts we adjust the resulting series for anticipated significant, non-recurring expenditure, permanent step changes, trends due to ongoing drivers, and any expected cost efficiencies.

D.5.5. Base-Step-Trend

307. We have used a 'base-step-trend'[22] approach to forecast expenditure that is recurring, including maintenance, system operations and network support (SONS) and portions of our non-network Opex. The approach is used by many utilities and economic regulators for forecasting expenditure. Figure 33 sets out the typical steps in developing base-step-trend forecasts.

Figure 33: Steps used in our base-step-trend approach



22 Base-step-trend approach has been used by energy network businesses regulated by the Australian Energy Regulator. The approach is also conceptually similar to the Commission's approach to forecasting Opex in recent DPPs

308. The base-step-trend approach begins with selecting a representative base year. The aim is to identify a recent year that is representative of recurring expenditure we expect in future years. If there are significant events (e.g. major storms) an adjustment is made to remove its impact.

309. We have used this approach for Opex portfolios with recurring activities. The key components include:

– Base year: identifying an appropriate historical base year and adjusting this for non-recurring items. This base cost is projected forward. For the CPP Period RY19 is used as the base year as this is the latest year with audited outturn expenditure.

– Include step changes: these are changes that are required to meet the needs of the network or to allow for external requirements. These can be one-off or ongoing changes and involve a change in the scope of work delivered from the base year.

– Apply trends: these reflect expected changes due to output growth and expected cost efficiencies and are applied after the step changes. The Commission uses an equivalent approach to set Opex allowances under its DPP model. We have adopted trends used by the Commission for DPP3 purposes in our modelling

To produce our CPP forecasts we adjusted the resulting series for expected cost efficiencies.

D.5.6. Price Book

310. Our Capex cost estimation process is built around a cost estimation 'price-book' that sets out a set of unit rates and component costs. Using this, we can develop robust cost estimates using a centrally managed dataset. These costs have been reviewed and tested by Jacobs, an engineering consultancy (see below).

311. We have assumed that historical unit rates used for volumetric works reflect likely future scopes and risks, at an aggregate level. We expect improved efficiency in our work delivery will help offset increasing safety-related costs (such as for improved traffic management) and increased costs associated with accessing the road corridor and private land.

D.5.7. Review of Unit Rates

312. We commissioned Jacobs to undertake a review of our price-book. Jacobs have undertaken a number of investigative reviews of EDB projects costs, including comparisons of EDB project budget estimates with the final capitalised project costs. To enable the review we supplied Jacobs with the following information:

– our price-book.

– examples of tailored cost estimates

– sample of historical projects costs.

313. In order to ensure that Jacobs clearly understood the use of our price-book and our costing methodology we spent time with the Jacobs team and developed, with them, a tailored cost estimate for a zone substation, underground cable, and overhead line project.

314. Jacobs proceeded to review our price-book unit rates and supplied us with a comparison between their typical unit rates and our unit rates (as set out in our price-book). This identified some potential refinements and cases where our rates were both greater and less than typical industry rates. We modified our rates to achieve better alignment with some of their benchmarks and finalised the price-book used for our CPP forecasts.

D.5.8. Future Efficiencies

315. Following consultation we reviewed our expenditure plans extensively and made substantial adjustments in direct response to customer feedback, independent verifier feedback, and internal challenge. This outcome aligns with feedback we received from customers that we should focus on affordability.

316. Reflecting the above, we have applied efficiency targets to our forecasts across most of our expenditure portfolio. Efficiency gains will be achieved by developing our asset management capability and making ongoing improvements in business support activities, including improved IT capability. These improvements will support future efficiency gains we are targeting from improved work coordination, increased delivery productivity, and better operational decision-making. We aim to work hard to drive efficiency into our design, procurement and delivery to make sure that we maximise the value we provide to customers.

Box 3: Efficiency adjustments

We plan to make material capability and capacity improvements over the CPP Period. We expect that efficiencies will result from these planned business improvements. Reflecting this we have applied specific efficiency adjustment factors to relevant portfolios. The efficiencies are based on a composite of potential efficiency sources that are discussed below.

- Contractor productivity: reflecting increased competitive tension and scale efficiencies that could be realised by the uplift in work and increased competitive tension.
- Works coordination: medium term as we move from addressing spot risks to fleet risks
- Improved decision-making: driven by asset management improvements, including expanded network analytics using better data; investment optimisation; and condition-based risk management
- Improving capability: improvements as we mature our systems and processes, aligned with our ISO55000 story. IT investments (e.g. EAMS) will enhance renewals through improved information; and simplify the as-building process, leading to some SONS efficiencies.

318. We have introduced these reductions and efficiencies so that future price increases are more affordable. We have responded to concerns regarding affordability and specific feedback from the independent verifier.

Appendix E. Renewals Capex

E.1. Introduction

319. This chapter outlines our renewals capital expenditure, describing our forecasting approach and setting out the drivers for replacing our assets. It describes the methodology in general and sets out details for each of our renewal portfolios and fleets.

320. Renewal of our assets when warranted by condition or other factors is essential for maintaining a safe and reliable network. Deteriorating condition increases the likelihood of failure. Other factors that may drive renewal are age (as in the case of assets such as batteries), obsolescence, including lack of spares and technical expertise, and declining performance.

321. Our network has seen a prolonged period of under-investment, right up until we started a major programme of pole renewals in 2017. The Fast Track Pole Programme (FTPP) was initiated when we uncovered a backlog of poor condition poles. While we have since replaced some thousands of poles, we still have a backlog of poles requiring renewal.

322. Over the period since the FTPP commenced we have observed an increasing deterioration trend across many of our other fleets. In particular, many of our crossarms, overhead conductors, zone substation indoor switchgear assets and protection relays have exceeded their expected lives, and present intolerable safety and reliability risks. A significant proportion of our subtransmission underground cables assets have also been identified as being in poor condition, presenting reliability and environmental risks.

323. Our focus during the CPP period[23] will be in the following areas:

- Addressing the pole backlog so that all poles identified as being in poor condition are replaced within regulated timeframes.
- Commencing a standalone crossarm replacement programme. While many crossarms have been replaced as part of pole renewals, the shorter expected life of crossarms means that many standalone crossarm replacements are warranted.
- Initiate replacement of the Waipori subtransmission overhead lines.
- Continuing with our distribution conductor renewal programme, with a focus on addressing low clearance spans.
- Commencing a LV conductor renewal programme, reflecting lessons and experiences gained from distribution conductor renewals.
- Addressing worker safety (arc flash) issues and poor performing zone substation assets, as highlighted during the independent network review in 2018.
- Continuing our programme to replace all electromechanical protection relays by RY24, recognising the risk associated with their degrading condition.

[23] We are proposing a three-year CPP period of RY22-24; we are required to submit five years of information as part of our application. For consistency we refer to the CPP period as the three-year period (RY22-24) within this document.

E.1.1. Our Asset Fleets

324. Our renewals portfolios and fleets are defined according to Table 13, below:

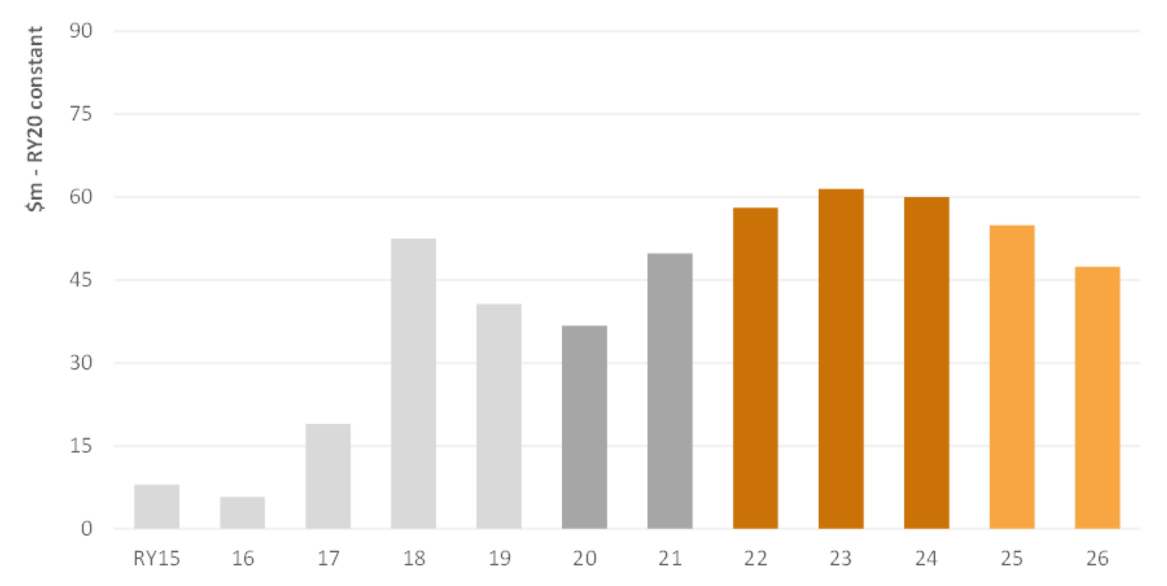
Table 13: Renewals portfolios and fleet

Portfolios	Fleets
Support Structures	Poles Crossarms
Overhead Conductors	Subtransmission Conductors Distribution Conductors Low Voltage Conductors
Cables	Subtransmission Cables Distribution Cables Low Voltage Cables
Zone Substations	Buildings and Grounds Power Transformers Indoor Switchgear Outdoor Switchgear Ancillary Zone Substation Equipment
Distribution Switchgear	Ground Mounted Switchgear Pole Mounted Fuses Pole Mounted Switches Reclosers and Sectionalisers Low Voltage Enclosures
Distribution Transformers	Ground Mounted Distribution Transformers Pole Mounted Distribution Transformers Voltage Regulators Mobile Distribution Substations and Generators
Secondary Systems	Protection DC Systems Remote Terminal Units Metering

E.2. Expenditure

325. A large proportion of our network was constructed in the 1950s-70s period. As many assets have an expected life of 50-60 years, a large proportion of the network has already or will soon become due for renewal. Failure to recognise the investment need and ramp up capability to do the work has left us in a 'catch-up' renewals phase, a period during which we will undertake a high volume of work to return the risks associated with our network to acceptable levels. Once this has been achieved, investment will reduce to steady state levels.

Figure 34: Renewals Capex



326. Renewals Capex began to increase in 2017, and since then has been dominated by the pole renewal programme. We have also commenced a number of other work programmes, most of which will ramp up over several years, producing the investment peak in RY23. The majority of the expenditure is on poles, crossarms, distribution and LV conductor and zone substation assets that are overdue for replacement, and which present a significant safety risk.

E.3. Key Drivers and Forecasting Approach

327. This section discusses the key drivers for renewals expenditure over the CPP period and how we forecast it. The relative importance of renewals drivers will vary by fleet.

E.3.1. Key Drivers

328. The drivers for asset renewal vary by asset type. The key drivers during the CPP period are set out in the following table.

Table 14: Key renewal drivers

Poles	**Condition/Public safety –** replace poor condition poles as identified during inspections and testing, including reducing the wood pole backlog to zero by RY24, to manage the public safety risk associated with pole failure. **Regulatory –** the regulatory timeline for red tagged pole remediation has not been met for several years. Achieving steady state pole renewals will also ensure these standards are met.
Protection	**Public safety –** protection schemes are highly critical to network operation and failure of protection to clear a fault poses a significant safety risk. **Obsolescence –** we have many aged relays in service for which we have limited or no manufacturer support or spares, and it is difficult to sustain maintenance skills. **Need for improved functionality** – added functionality of modern relays will enable us to better manage network protection.
Zone Substations	**Worker safety** –staff/contractors are exposed to arc flash hazards associated with ageing equipment, particularly indoor switchgear. **Condition –** some assets in our zone substations are in poor condition or have not been well maintained, presenting a reliability risk.
Overhead Conductors	**Public safety –** aged/poor condition conductor is resulting in poor performance and increased numbers of conductor drops over the last 5 years. Low clearance spans also present a public safety risk, as well as violating legislated requirements. **Age/condition** – the Waipori lines are oldest conductors in the network. As these are made from copper, which becomes brittle with age, they present an unacceptable safety and reliability risk. For our distribution and LV conductor fleet, we have aged copper and No 8 wire types which are in poor condition and are performing poorly.
LV enclosures	**Public and worker safety** – we need to undertake renewals to avoid exposing staff/contractor and public with the safety risk associated with ageing/poor condition LV enclosures.
Crossarms	**Condition** – we have assessed and replaced a large number of crossarms on wooden poles as part of the pole renewal programme. However, many crossarms, including those situated on both concrete and wood poles are yet to be inspected. As may have exceeded expected life, we expect a large number to be in a condition that warrants replacement. **Public safety –** Poor condition crossarms present a safety hazard as they may cause conductors to disconnect from the insulators, or result in conductor drop.
Cables	**Public safety –** cast iron pothead terminations have explosive failure mode, which can result in bitumen and the cast iron housing failing on the ground. These are located in public areas resulting in a safety risk.

329. Renewal drivers are discussed in further detail in subsequent sections of this chapter.

E.3.2. Forecasting Approach

330. We take a bottom up approach to forecasting, combining estimated unit prices with forecast renewal quantities for each asset type. The specific approaches used to forecast quantity vary by asset fleet. Most of our forecasts are volumetric, with a tailored approach taken for large projects with site-specific requirements, such as zone substation or underground cable renewals. Data availability constrains our ability to apply more sophisticated models in some cases, and we will be looking to improve our datasets to support improved forecasting.

Volumetric Forecasts

331. We use volumetric forecasting for smaller, higher volume works that are routine and uniform. We forecast the volume of remediation required, but not the specific assets to be replaced (which are only identified nearer to the time of renewal).

332. Volumetric forecasts also cover specific programmes of work to address type issues or defects (for example, where we have identified conductor clearance violations or cast iron pothead cable terminations).

333. We use three main methods for volumetric forecasting:

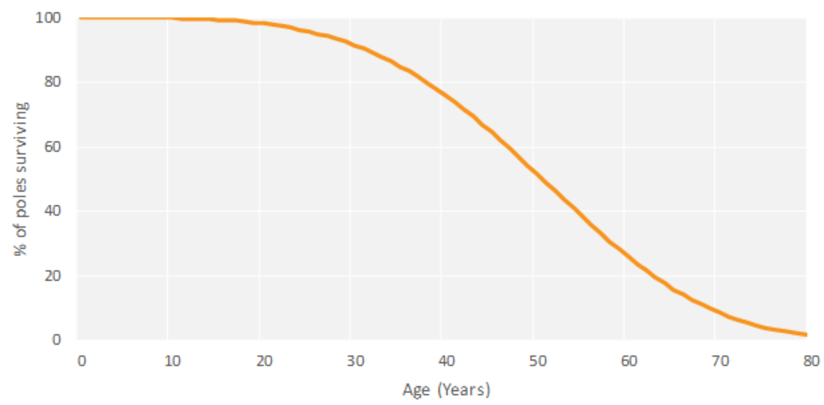
- Survivor curves use historical replacement data to calculate a survivorship function and associated replacement rates. They are used for fleets with high replacement quantities, such as poles.
- Repex models assume a normal replacement distribution around an expected life. The distribution is then used to calculate a replacement rate. These models are used for fleets where historical replacement information is scarce, such as overhead conductors and crossarms.
- Age based forecasts are a simplistic model using the assets age and their respective expected lives to develop a forecast. We use this approach for fleets where there is insufficient data to develop survivor curves and age is considered a reasonable proxy for condition or other replacement driver.

334. The following describes our survivor curve and Repex models in more detail.

Survivor curve model

335. Survivor curves are informed by historical asset replacement and/or failure data. We use this approach where there is sufficient information for such a model to be statistically robust. To date, we only have sufficient information to develop a survivor curve for a subset of one fleet – wooden poles. This is shown in Figure 35, below.

Figure 35: Wood pole survivor curve



336. The survivor curve represents the 'life' achieved by our wood pole population as informed by our historical data. It shows the probability of an asset 'surviving' to reach a certain age. A survivor curve forecast model converts the survivor curve to a replacement rate curve, where the replacement rate curve shows the likelihood of replacement of an asset at a given age. The replacement curve is applied to the wood poles age profile to produce an annual volume forecast.

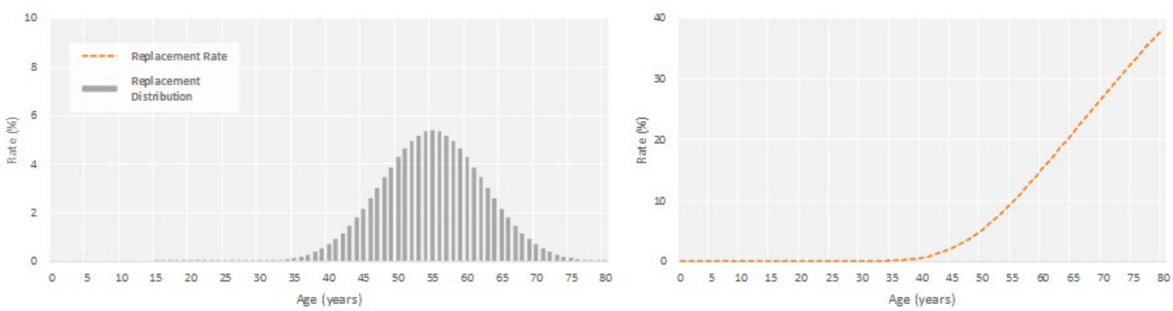
337. Survivor curve models are a robust forecasting method as they use historical replacement data from our network, which takes into account factors such as condition, degradation, location and the characteristics of different types of wood.

__Repex Models__

338. Repex models apply the same concept as survivor curve models, but are used for fleets where there is insufficient historical replacement data. The replacement distribution in this case is instead based on a normal or Weibull distribution around the expected life attributed to the asset type.

339. Figure 36, below, shows an example of a normal replacement distribution around an assumed expected life of 55 years (left) and its corresponding replacement rate.

Figure 36: Repex replacement distribution and rate example



340. The replacement rate represents the likelihood that replacement of an asset will be warranted at any given age. The Repex model applies the replacement rate to the fleet age profile to produce an annual volume forecast.

341. This approach is more robust than simply assuming that equipment fails at a particular age. It is widely used in the Australian electricity sector as required by the Australian Energy Regulator (AER).

Tailored Projects

342. Where projects are 'large' and one-off with well-defined scopes and timings we take a tailored approach to forecasting expenditure. This approach identifies specific assets and solutions to meet specific site requirements. Tailored projects are generally triggered primarily by asset health. In the case of zone substations we combine asset health and criticality to develop a risk framework to identify renewal needs. Other renewal works for which we use tailored forecasts are subtransmission cable renewals and the Waipori subtransmission overhead line renewal. Refer to Appendix D for more information on how we cost these tailored projects.

E.3.3. Asset Health Indices

343. We have developed Asset Health Indices (AHI) for a number of our asset fleets. AHI represent the expected remaining life of an asset and provide a proxy for probability of failure. We have developed an AHI framework that allows us to view current health, based on type issues, survivorship analysis, and age. We can then compare this to a scenario where we undertake the forecast level of investment, or where we undertake no investment.

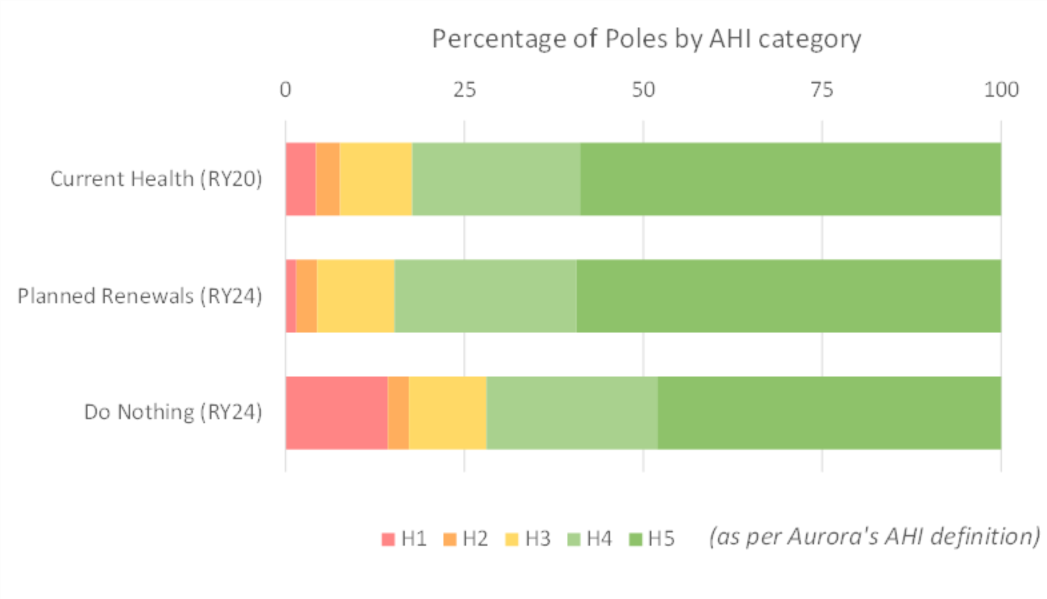
344. Our AHI definition is as per Table 15:

Table 15: Asset health indices

AH Score	Category Description	Expected Replacement Period
H1	Asset has reached the end of its useful life.	Within one year
H2	Material failure risk, short-term replacement	Between 1 and 3 years
H3	Increasing failure risk, medium-term replacement	Between 3 and 10 years
H4	Normal deterioration, monitor regularly	Between 10 and 20 years
H5	As new condition, insignificant failure risk	Over 20 years

345. The forecast AHI example below shows the current asset health of our poles, together with projected health assuming our renewal plan is fully implemented and a hypothetical 'do nothing' scenario.

Figure 37: Poles asset health example

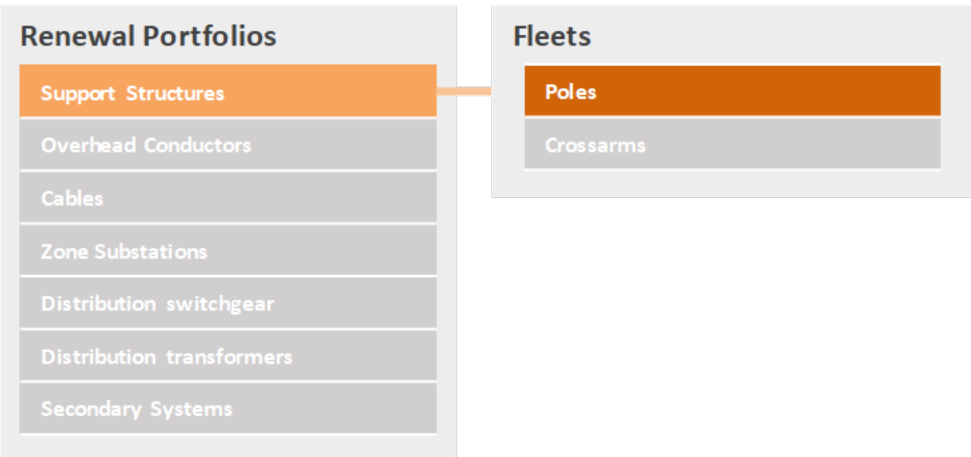


346. The 'do nothing' scenario estimates the future health of the fleet if no renewals are undertaken by RY24. Often, as in this case, it will not be a viable option due to the safety and reliability implications of the scenario.

E.4. Poles

347. This section discusses the drivers of poles renewals, the forecasting approach we use for this volumetric fleet and the forecast renewals Capex. Poles and crossarms together form our support structures portfolio.

Figure 38: Support structures portfolio; pole fleet



348. Our network includes approximately 54,000 poles. The majority of our poles are wooden or concrete, but we also have a small number of steel poles. This section sets out our proposed level of investment during the CPP period and the associated rationale.

For more details on pole quantities, types and failure modes, please refer to AMP chapter 8. All pole expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Distribution and LV lines'.

E.4.1. Investment Drivers

349. This section sets out the main investment drivers for our pole fleet during the CPP period and how they have informed the forecasts.

Pole Backlog

350. Our pole fleet has been subjected to a prolonged period of under-investment. As such, since starting our (updated) pole inspection and testing programme, we have identified end of life poles at a faster rate than we have been able to remediate them. This has resulted in a backlog of poles awaiting replacement. These poles have failed strength tests and include defected poles that have been assessed as being in acceptable structural condition at the ground line, but which suffer from a significant split in the top of the pole. If the split extends near to or past where the crossarm is attached to the pole, and assuming the crossarm cannot be lowered to a level not affected by the split without breaching regulated clearances, the whole pole must be replaced. Based on condition data as of 31 March 2019, the total backlog comprises ~2,100 wood poles. The required timeframe for addressing the backlog is within 24 months, as of 31 March 2019; the AHI for all of these poles will become H1 by the end of RY20 if not replaced.[24]

Condition/Asset Health

351. Managing fleet health is a key driver for our poles fleet. Failure to manage fleet health will result in an increasing number of H1 and H2-classed poles and an associated increase in associated operational and safety risk. Figure 5 shows the health of our fleet of poles, which indicates that approximately 8% of our poles are currently classified as H1 or H2. If we fail to invest (the 'do nothing' scenario) we expect this to increase to approximately 14% by RY24.

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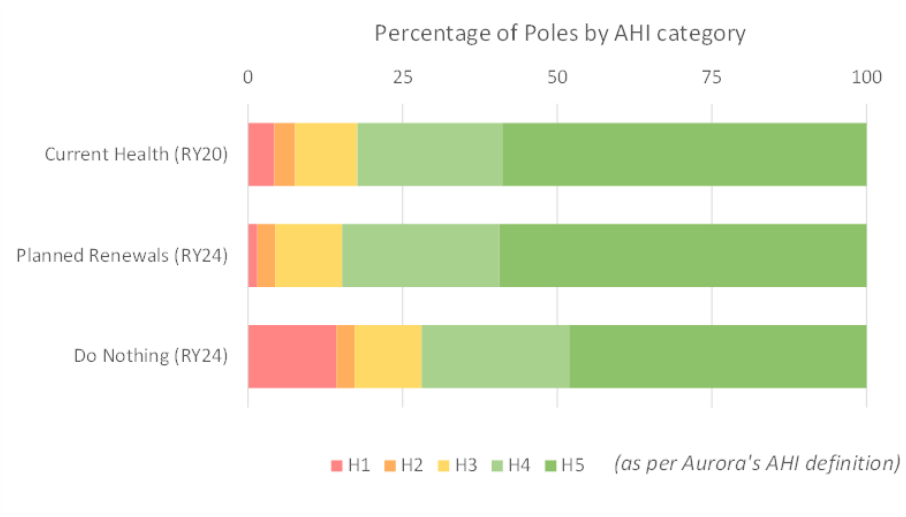
[24] Information presented in this chapter is on a 2019 'base'. Further information on the current state of the poles backlog is given in the executive summary and chapter 8 of our asset management plan.

Figure 39: Poles asset health

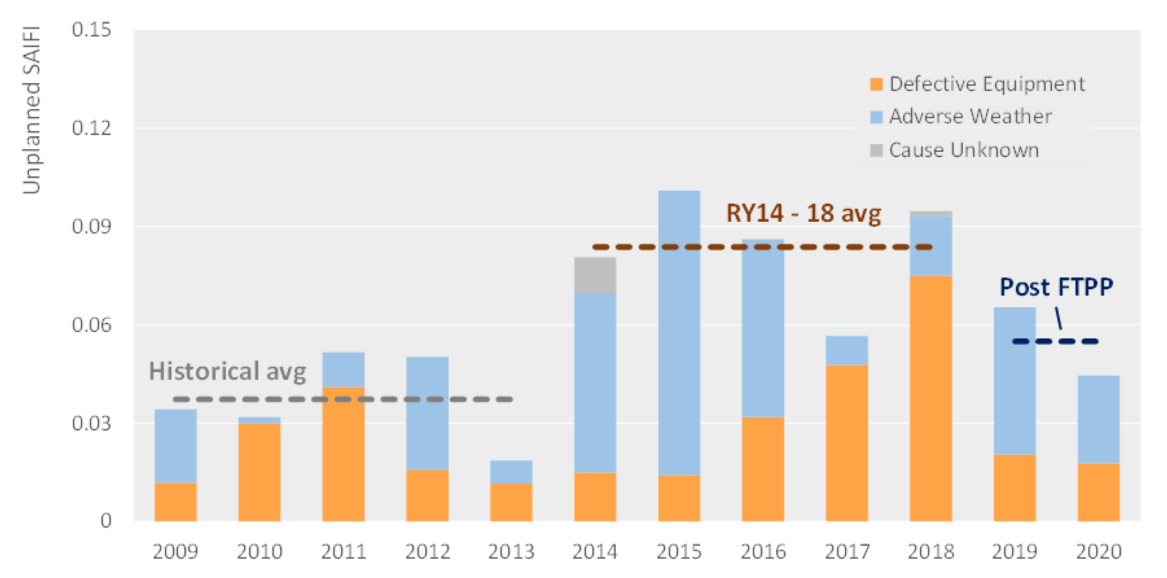


352. Instead, implementing our proposed pole renewal programme (involving replacing ~3,000 poles over the CPP period) will reduce the percentage of H1/H2 condition poles to approximately 4% in RY24. The vast majority of the replacements will be wood poles. Our concrete and steel pole fleets are in relatively good condition and we do not anticipate having to replace many of them. We plan to eliminate our pole replacement backlog by RY24 and even with the additional poor condition poles entering the replacement pool each year, we expect to reach steady-state pole renewal levels by then.

Historical Performance

353. Figure 40 shows the historical (un-normalised) SAIFI attributable to poles, as a proxy for the total number of pole failures. It shows that pole failures have increased significantly in recent years compared to historical levels. A significant proportion of the failures have been categorised as 'Adverse Weather', however, it is likely that the poles that failed during adverse weather events were already in poor condition. Early design standards with lower thresholds may have exacerbated this effect. Our independent network reviewer has noted that the reduction in failures in RY19 is potentially attributable to the recent increased levels of pole renewal work. We have had further reductions since in RY20, indicating our pole renewal programme is effective. While the reduction may indicate the start of a declining trend in failures, we still have a known backlog of poor condition poles and an ageing fleet, it is important that we maintain replacement rates to return the fleet to a satisfactory state.

Figure 40: Pole failure SAIFI trend



E.4.2. Forecasting Approach

354. We take a volumetric approach to forecasting renewal Capex for poles (i.e. a unit rate multiplied by a forecast replacement quantity). Our forecast of proactive pole replacement volumes is derived from a survivor curve and our poles age profile. Our pole survivor curve is based on historical wooden pole renewals (or age at removal from service). Our pole forecast does not include poles that will be replaced during conductor replacements -these replacements are accounted for in our conductor renewals. We apply a single unit rate to forecast work volumes. The rate reflects the costs of actual pole replacements undertaken since we established our Field Services Agreements (FSAs) in RY19 and makes an allowance for future efficiency gains.

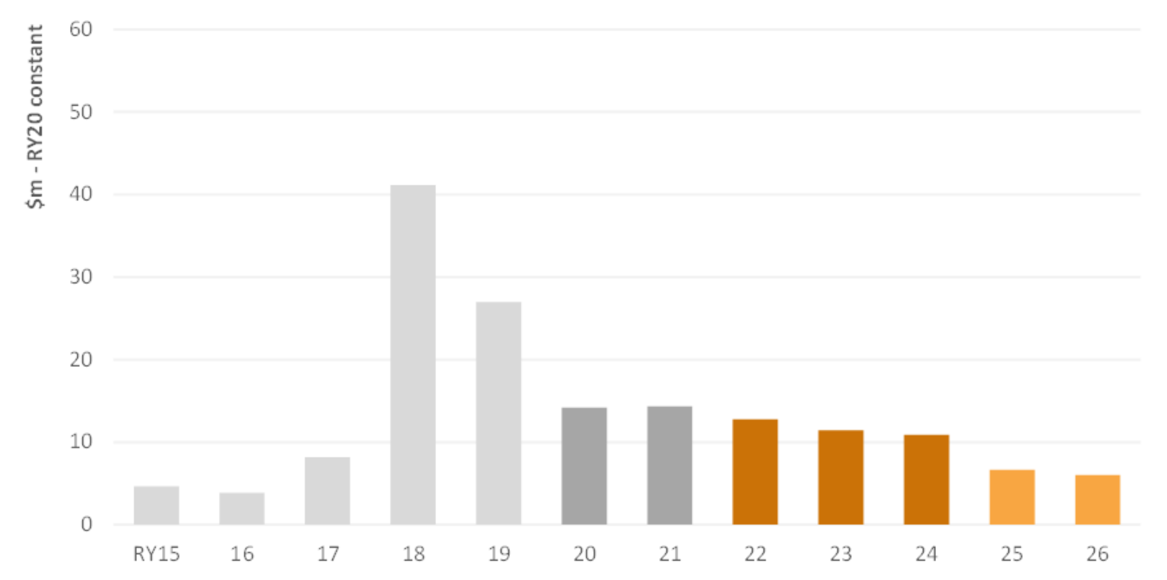
Table 16: Summary of pole renewals approach

Renewal trigger	**Proactive condition-based:** inspection and testing identify defected and poor condition poles that need to be replaced. Any red tag poles identified are prioritized for replacement on a criticality basis.
Forecasting approach	**Survivor curve**: historical wooden pole defects have been used to derive a probabilistic curve that is used to forecast likely future pole replacements.
Cost Estimation	**Historical costs:** unit rates are based on the average costs of historical pole replacement works. This includes the replacement of all crossarms and occasionally replacing pole mounted equipment, such as distribution transformers, switches and fuses.

E.4.3. Poles Renewal Capex

355. Figure 41, below, shows our historical and proposed poles investment in the RY15 to RY26 period.

Figure 41: Poles renewals Capex



356. The high expenditure, in RY18 and RY19, reflects our Fast Track Pole Replacement Programme (FTPP). We continue to have a backlog of replacements but have reduced the annual number of replacements to a level we are able to deliver on an ongoing basis. Our forecast investment will remain 'elevated' (relative to future) up to RY24, after which it drops to steady-state levels as the aggregate health of the pole fleet improves. Our backlog of required pole replacements will be reduced to zero by RY24.

Box 4: Poles forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

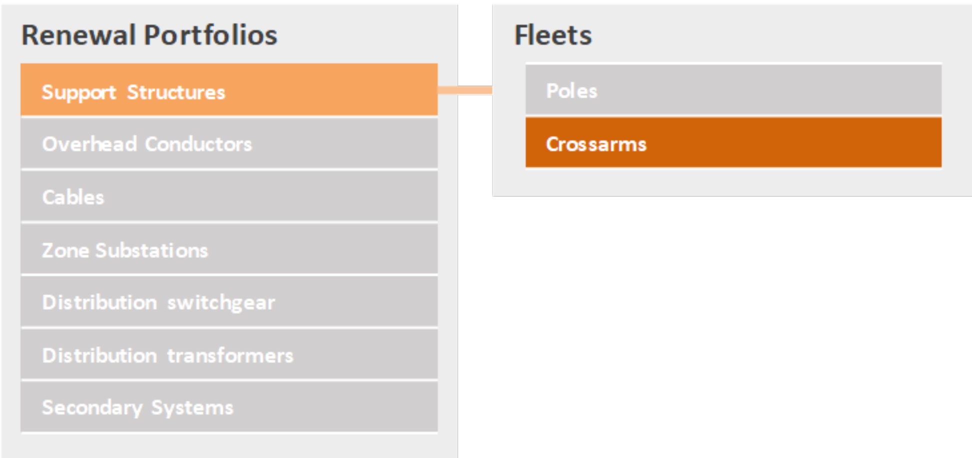
- Clear, prudent drivers: our poles fleet has seen a prolonged period of under-investment. This is reflected in declining historic performance and a backlog of poor condition poles. However, our performance trend has improved in recent years, which can be attributed to our pole renewal programme. We must continue to invest or we expect our pole failures will increase, with the associated public safety risks. Renewals will continue at the current, relatively high level for several years until the backlog has been addressed and we achieve steady state. We are planning to reduce the percentage of H1/H2 poles to 5% by RY24, as opposed 17% under a 'do-nothing' scenario. This in turn reduces safety risks associated with poles and the number of unplanned network outages we expose to consumers.
- Cost effective: Reactive / unplanned pole failures are generally more costly to replace compared to proactive / planned replacements. As we transition to steady state, by RY24, we expect a reduction in the number reactive pole replacements, effectively lower overall fleet cost as we are proactively replacing poles

- External review: external specialists were engaged to undertake a network review in November 2018. They noted that our pole replacement programme has slowed a declining performance trend. This further supports our approach of continuing pole replacements at current levels.
- Review and moderation: Our forecasts have been tested and reviewed by our executive management and the Board, and the forecasts have been moderated based on feedback and discussion. Unit rates were reduced, for more details refer to efficiency point below.
- Verifier review: our forecasts has been reviewed by the verifier and the forecasts have been considered reasonable without any further changes.
- Efficiency: the pole replacement unit rate, which is based on recent historical costs, has been reduced by a small percentage to reflect efficiency gains from asset management improvements, increased competition amongst our service providers and better works delivery processes.

E.5. Crossarms

358. This section details the crossarms' investment drivers, forecasting approach and renewals Capex. Crossarms is part of the Support Structures portfolio, as depicted in Figure 42.

Figure 42: Support structure portfolio; crossarms fleet



359. We have approximately 95,000 crossarms in our network the majority of which are wooden crossarms. The following sets out our proposed standalone crossarm investment level in the CPP period and the associated drivers. Replacements of crossarms that are associated with pole and conductor renewals are not included here and are discussed elsewhere.

For more details on crossarm types, age profiles and failure modes, please refer to AMP chapter 5. All crossarm expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Distribution and LV lines'.

E.5.1. Investment Drivers

360. The main investment drivers for our crossarm fleet during the CPP period are described below, together with how these have informed the forecasts.

Overdue Crossarms

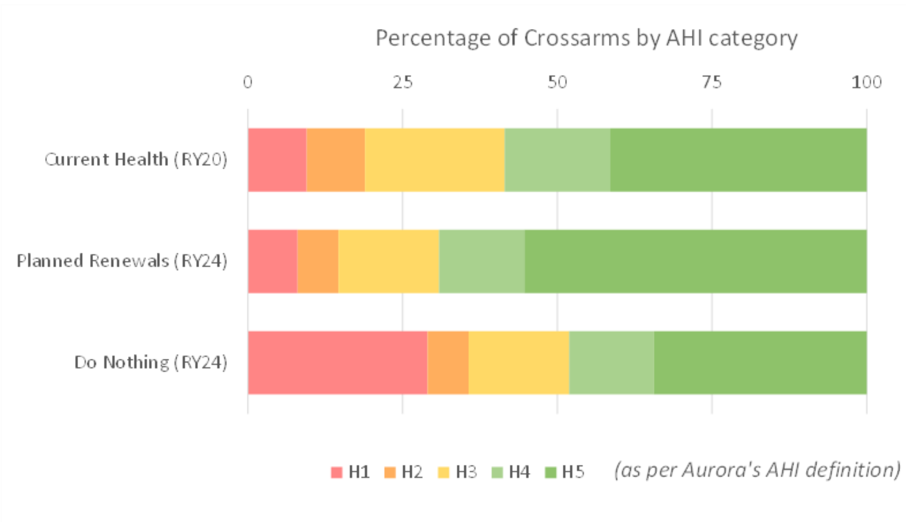
361. A majority of our crossarms have not been inspected in some years and we have not previously had an active standalone crossarm renewal programme. We expect that many of them are in poor condition, having exceeded their expected life. Wooden crossarms typically reach end of life due to age-related cracking and loss of strength as the wood dries out, or because of rotting on the upper side due to moisture ingress over time. Crossarms with pin-type insulators installed (i.e., all crossarms prior to the Fast Track Pole Programme, when we changed to using 'post' type insulators) are more vulnerable to compromised bolt holes due to conductor movement, causing insulators to lean and damage the crossarm (leading to a defect).

362. Poor condition crossarms (or parts of the crossarm assembly such as insulators) may fail, causing pole fires, inadequate conductor clearances or conductor dropping to the ground. Such events would expose the public to fire or electrocution hazards.

Asset Health

363. Figure 43 shows crossarm fleet asset health. Our analysis indicates that 10% of our crossarms are at end of life (classified as H1) at RY20. This is primarily due to the aged crossarm fleet population. We expect ~40% of the population to need replacement over the next 10 years (comprising H1 to H3). Our proposed level of investment will improve overall fleet health, helping to manage the risks associated with crossarm failures. As a consequence of large volumes of overdue assets, our levels of H1-classified crossarms will remain higher than desirable throughout the CPP period. However, as we prioritise identification and implementation of renewal requirements by criticality, we expect the residual risk to be relatively low.

Figure 43: Crossarms asset health



E.5.2. Forecasting Approach

364. Our crossarm forecast consists of replacements of poor condition crossarms, identified during overhead lines inspections. We use a volumetric approach to forecasting renewal Capex for crossarms, i.e. a unit rate multiplied by the forecast replacement quantity in each year. The forecast replacement quantities are calculated using the Repex methodology, with an expected life of 55 years (based on the average age of poor condition crossarms identified from our latest pole inspections). We have used the Repex methodology instead of a survivor curve approach as we currently do not have a large enough sample of condition data to reliably inform a survivor curve.

365. The forecast is for standalone crossarm replacements; crossarms replaced with new poles or conductors are excluded from this forecast and covered under the respective poles / conductor forecasts. Our unit rates are based on an average from our recently completed standalone crossarm replacement projects.

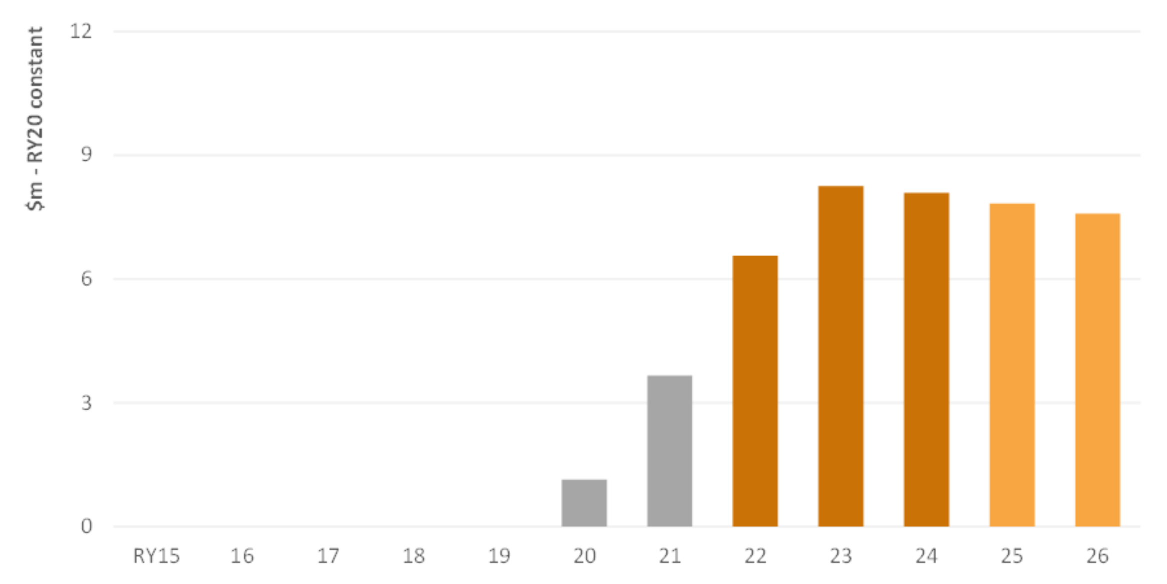
Table 17: Summary of forecasting approach

Renewal Trigger	**Proactive condition-based** replacements based on inspection results, identifying poor condition crossarms.
Forecast approach	**Volumetric** forecast using the Repex methodology and age / expected lives.
Cost Estimation	**Actual project costs** of standalone crossarm replacements carried out recently.

E.5.3. Crossarm Renewals Capex

366. Figure 44 shows our historical and proposed crossarm investment in the RY15 to RY26 period.

Figure 44: Crossarms renewals Capex



367. Historically, we have only replaced crossarms when replacing poles or when they have failed in service. However, a large proportion of our crossarm population have now exceeded their expected life and there is an increasing need to begin a standalone crossarm replacement programme to address the failure risk associated with poor condition crossarms. We began our standalone crossarm replacement programme in RY20, with the intention of increasing year on year renewal levels, such that we will have replaced ~10k crossarms by RY24

368. The planned renewals of crossarms to RY24 will:

- address poor condition crossarms and reduce the number of H1s by ~20%, thus reducing associated safety and reliability risks
- enable us to replace crossarms in a planned manner, which is generally more cost effective than unplanned work
- reduce the proportion of overdue crossarms in the fleet and move us to a position where steady state levels are achievable post RY30.

369. Beyond the CPP period, we expect to reduce our expenditure slightly as we prepare to transition to steady state levels. We intend to continue standalone crossarms replacements for the foreseeable future.

Box 5: Crossarms forecast justification

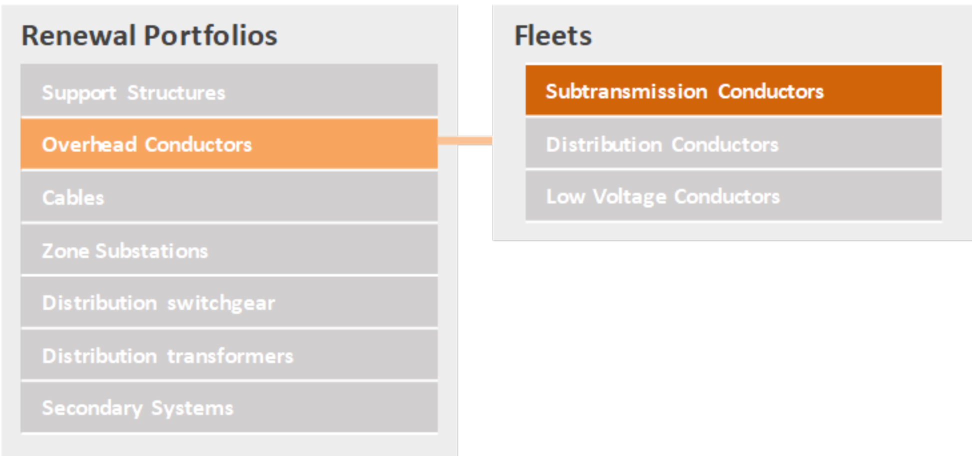
We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: a significant proportion of the fleet are overdue for replacement. A standalone renewal programme is needed to address poor condition crossarms. Failure to invest now will likely show up as more crossarm failures and increased associated public safety risks. Our planned renewals will improve asset health, reducing unplanned outages and associated reliability and safety risks.
- Verifier review: the crossarms forecast has been reviewed by the verifier and we have incorporated their feedback, applying a unit rate reduction over time (more details below).
- Review and moderation: our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge. We have deferred non-critical overdue crossarms to be replaced by RY30.
- Efficiency: the crossarm replacement unit rate, which is based on recent historical costs, has been reduced by a small percentage from RY22 to reflect efficiency gains from asset management improvements, increased competition amongst our service providers and better works delivery processes.

E.6. Subtransmission Conductor

371. This section details the subtransmission conductor investment drivers, forecasting approach and forecast renewals Capex.

Figure 45: Overhead conductors portfolio; subtransmission conductors fleet



372. We own approximately 524 km of overhead subtransmission conductor. Approximately 75% of the conductor types are aluminium core steel reinforced (ACSR), 1% are all aluminium conductor (AAC) and the remaining 25% are copper. The average age of our subtransmission conductors is 50 years and a significant amount, primarily copper, have exceeded their life expectancy.

Please refer to AMP chapter 8 for more details on age profiles, quantities and types. All subtransmission expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Subtransmission' (this category includes subtransmission cables and lines).

373. The following sets out our proposed investment on subtransmission conductors during the CPP period and the associated drivers.

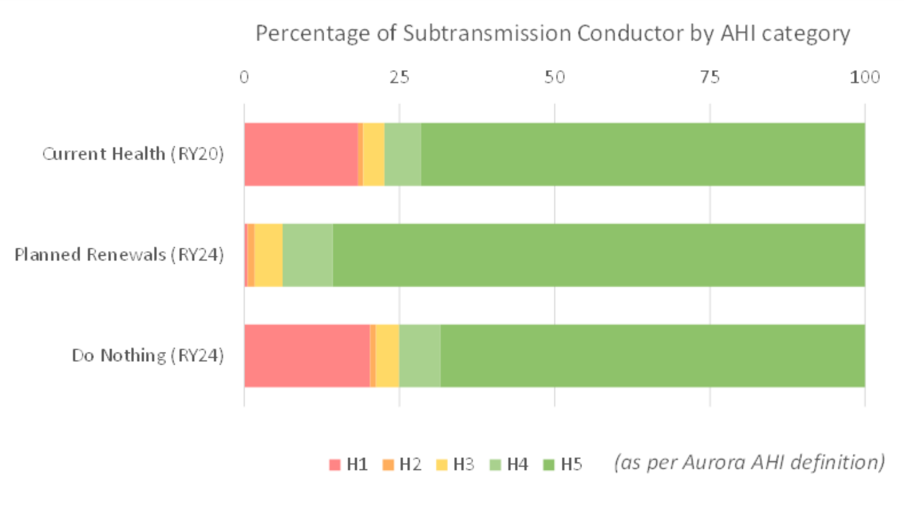
E.6.1. Investment Drivers

374. This section sets out the main investment drivers for our subtransmission conductor fleet during the CPP period and how they have informed the forecasts.

Asset Health

375. Figure 46 shows the asset health of our subtransmission conductor fleet.

Figure 46: Subtransmission conductor asset health



376. A significant volume of conductor, primarily the copper conductor used for our Halfway Bush to Berwick line, has exceeded its expected life. We are planning to replace these lines by RY24, reducing our H1 levels to 1% of our fleet. More details regarding the Halfway Bush to Berwick line renewals are described below.

Halfway Bush to Berwick Line Renewal

377. The oldest copper subtransmission conductors on our network are on our three Halfway Bush (HWB) to Berwick (BWK) 33 kV lines[25], which are referred to as Lines A, B and C. Lines A and B were originally constructed in 1907 to transmit power from the Waipori Hydro Scheme to Dunedin. The transmission capacity between the Waipori Hydro Scheme and Dunedin was increased further in 1959 with the installation of Line C. All three lines utilise small sized, single / double strand, copper

[25] These lines continue from Berwick to the Waipori power station. The Berwick–Waipori section of the lines is owned by TrustPower. The Mahinerangi Wind Farm (owned by Tilt) injects power at Waipori power station.

conductor which has been known across the industry for poor reliability performance in comparison to other conductor types.

378. The three lines deliver electricity to a significant large number of consumers to the west of Dunedin and also transport a significant amount of power from the Waipori/Mahinerangi power stations to the national grid.

379. Given the age of the copper conductors, coupled with the importance of the customers supplied by these lines we need to proceed to replace the existing lines. We have considered a wide range of different options, concluding that the most cost-effective solution involves the installation of two higher capacity, 33 kV overhead lines between Halfway Bush and Waipori.

E.6.2. Forecasting Approach

380. We have developed a detailed customised estimate for the costs associated with the HWB to BWK 33 kV lines. The estimate is based on a staged rebuild of the lines in order to minimise the impact on the generators/consumers. We propose rebuilding the lines in three stages, each of which will occur during the February to April period when power usage is low and generation output is low (due to lighter water/wind flows). In order to reduce the time to erect the new lines we propose employing steel poles that use pre-installed foundations. In addition, we plan to significantly increase the span lengths which will reduce costs and improve visual amenity. Our cost estimate for the rebuild is spread over the RY20-23 period, with the initial design works occurring in RY20.

381. Our forecast also includes a small volume of subtransmission conductor replacements that do not form part of the Halfway Bush to Berwick line replacement project. These additional conductor replacements will be identified during overhead line inspections, and we use a volumetric approach to forecasting renewal Capex for them. The method involves the multiplication of a unit rate by the forecast replacement quantity, which is established using a Repex approach. Our methodology uses a normal distribution based on a life expectancy that varies by conductor type, size and distance from the coast. The Repex approach was chosen in preference to a survivor curve approach as we do not presently have a large enough sample of condition data to develop a reliable survivor curve.

382. Table 18 summarises our forecasting approach for subtransmission conductors.

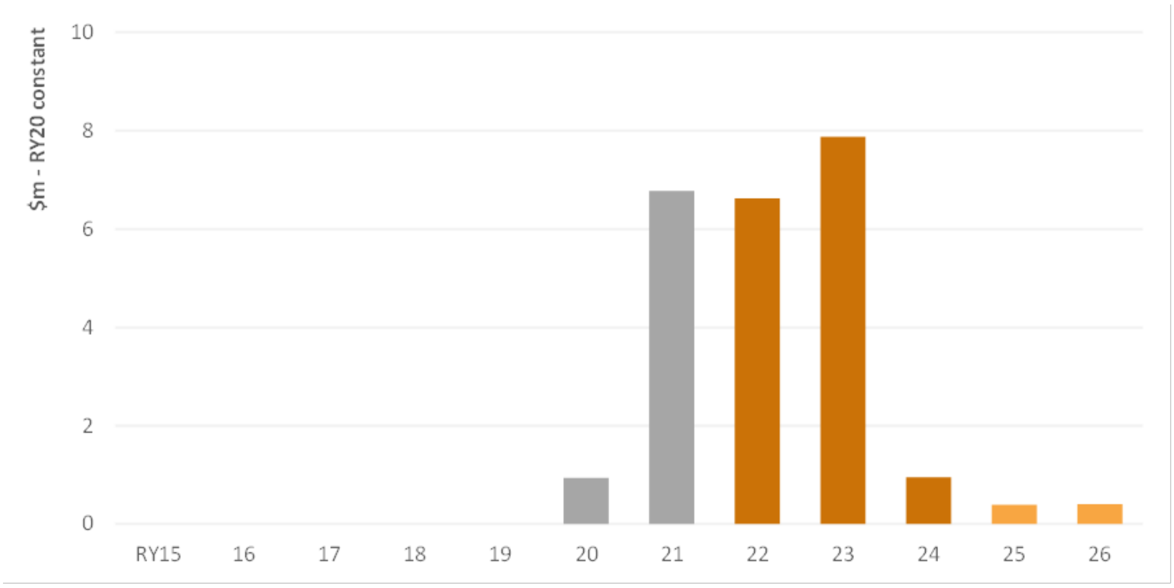
Table 18: Summary of subtransmission conductor approach

Renewal trigger	**Scheduled project:** the Halfway Bush to Berwick lines are in poor condition and the conductors/poles/line fittings have significantly exceeded life expectancy. **Proactive age-based:** we plan to replace subtransmission conductors based on age, expected life, conductor size and location, which are a proxy for conductor condition. Replacements will be prioritized by criticality.
Forecasting approach	**Scheduled project:** based on an identified renewal need for the Halfway Bush to Berwick lines. **Volumetric forecast** using the Repex methodology and age / expected lives.
Cost Estimation	**Customised estimate**: the renewal costs for the Halfway Bush to Berwick lines are based on a detailed project estimate. **Estimated costs:** unit rates are based on estimates which have been reviewed by an external consultant. The costs include conductor stringing, all fittings to attach the conductors and conductor jointing. The costs of poles and pole top hardware (i.e. insulators and crossarms) are included.

E.6.3. Subtransmission Conductor Renewals Capex

383. Figure 47 shows our historical and proposed subtransmission conductor investment in the RY15 to RY26 period.

Figure 47: Subtransmission conductors renewals Capex



384. Historically we have not undertaken many subtransmission conductor replacements, but in RY20 we began initial investigations for the replacement of the HWB to BWK lines. During the period RY20-23 we propose to significantly increase expenditure, primarily to replace these lines (planned to be commissioned by RY24). Subsequent to RY24 our expenditure will return to a steady-state replacement level.

Box 6: Subtransmission conductors forecast justification

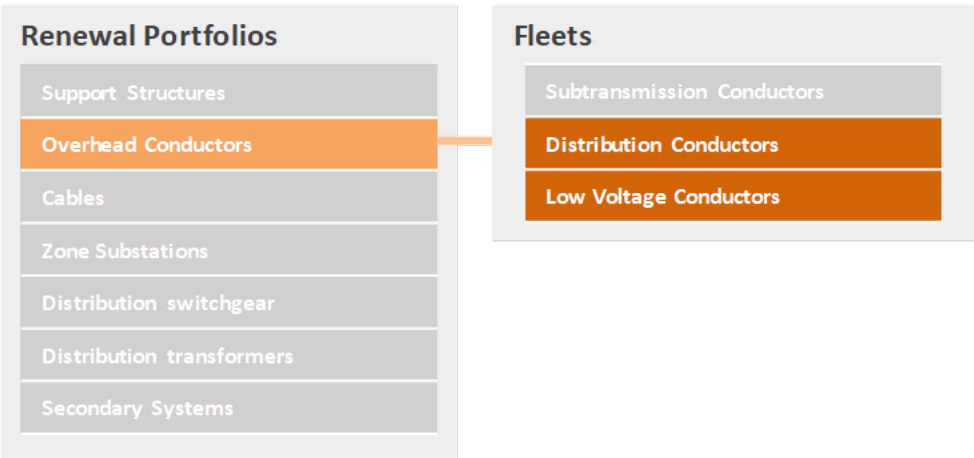
We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: a significant portion of our expenditure involves the renewal of overhead copper conductor on lines that were installed more than 100 years ago. These lines deliver electricity to a significant number of consumers. Replacing these conductors will ensure continual reliable supply to our customers.
- Cost effective: our proposed replacement design for the Halfway Bush to Berwick lines involves replacing three overhead 33 kV lines with two higher capacity lines. We propose competitively tendering the construction of the new lines.
- Customer impact: we propose to undertake the renewal work during the February to April period, when generation output and power consumption is low. This minimises the outage impact on customers.

E.7. Distribution and Low Voltage Conductors

386. This section details the investment drivers, forecasting approach and forecast renewals Capex for our distribution and low voltage conductors. This section relates to the overhead conductors' portfolio as per the following diagram.

Figure 48: Overhead conductors portfolio; distribution and low voltage conductor fleets



387. We own approximately 2,300 km of overhead distribution conductor, comprising No.8 wire, aluminium core steel reinforced (ACSR), copper and aluminium types. In comparison, we have approximately 1,600 km of overhead low voltage (LV) conductors including dedicated streetlighting.

Our LV conductors fleet comprises primarily aluminium and copper conductor types and a relatively small volume of ACSR.

Please refer to AMP chapter 8 for more details on age profiles, quantities and types. All Distribution and LV conductors expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Distribution and LV lines'.

388. The following section sets out our proposed investment on distribution conductors during the CPP period and the associated drivers.

E.7.1. Investment Drivers

389. The following details the main investment drivers for our distribution conductor fleet during the CPP period and how they have informed the forecasts.

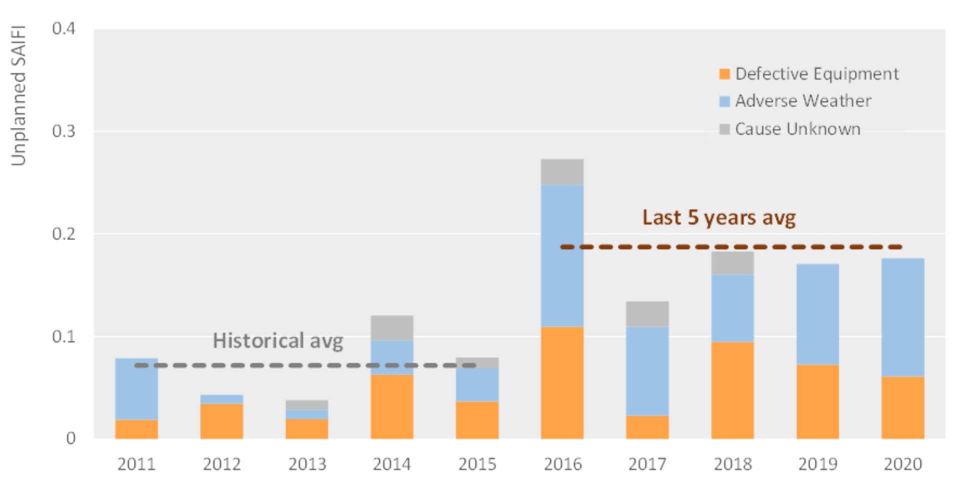
Clearance Violations

390. There are currently 225 conductor spans across road crossings that do not meet current modern clearance standards.[26] Many of these violations were created when roads were re-sealed, lifting the road level. Some road crossings may have been compliant at the time of installation, but are not compliant with 'new build' clearances, as clearance requirements have changed with time. These are inherently unsafe, particularly in the presence of heavy haulage vehicles. However, we have controls in place to manage these until such time as we are able to replace them. This includes permits from council required for oversized loads, which involve checking with utilities on clearances.

Historical Distribution Conductor Performance

391. Figure 49 illustrates our historical SAIFI, as a proxy for frequency of distribution conductor drops recorded on our network over the past 10 years. This indicates an increasing trend.

Figure 49: Distribution Conductor drops



[26] As per NZECP34, New Zealand Electrical Code of Practice for Electrical Safe Distances

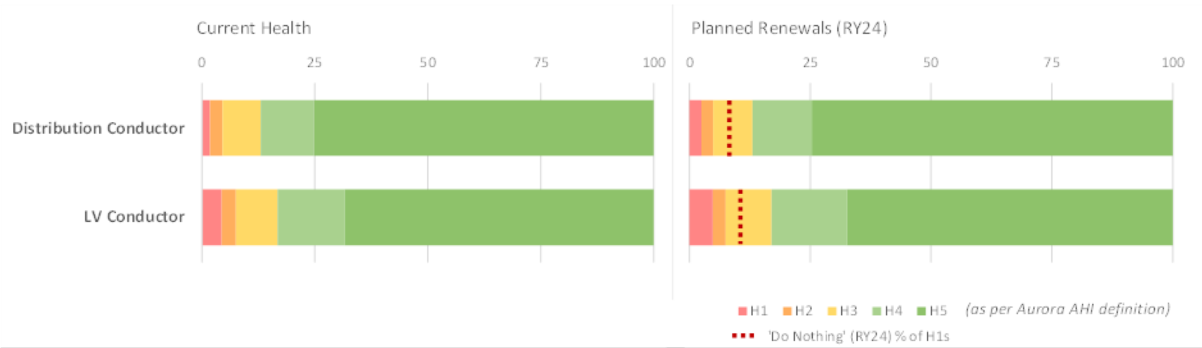
392. Many of our conductor drops are related to 'adverse weather'. As we design our overhead lines to handle these weather loads/situations, the apparent increase in the five-year averages is concerning, likely reflecting the ageing fleet. Our performance data is not reported by type, but anecdotally we believe that most of the recent events involve No 8 wire or copper conductors failing midspan and ACSR conductor joint and fitting failures caused by poor historic workmanship.

393. Conductor drops present a major public safety risk. Most faults resulting from a conductor on the ground are cleared through automatic isolation (i.e. protection or fuses), so the line does not remain live. However, a small number of high impedance faults are unable to be automatically cleared; in these cases the conductor remains live on the ground, exposing the public to both fire and electrocution hazards.

Condition/Asset Health

394. Figure 50 shows asset health of our distribution and LV conductors.

Figure 50: Distribution and low voltage conductor asset health



395. The ageing copper and No 8 wire type conductor are the predominant drivers of poor health for distribution conductors.[27] For LV conductor, copper type conductor is the main driver of poor health. Our proposed level of investment will maintain overall fleet health, helping manage the risks associated with conductor failure. We are planning to replace ~170 km of distribution and low voltage conductors over the RY22 to 24 period. If we do not invest as depicted by the H1s in the 'do nothing' scenario, 8% / 10% of our distribution / LV conductor fleets respectively, will be at elevated risk of failure, creating intolerable public safety risk.

E.7.2. Forecasting Approach

396. We use a volumetric approach to forecasting renewal Capex for distribution and LV conductors. This involves multiplying a unit rate by the forecast replacement quantity. The forecast quantity is established using a Repex approach, using a normal distribution based on a conductor life expectancy which varies by type, conductor size and location. The Repex methodology was used in preference to a survivor curve approach as we do not presently have a large enough sample of condition data to develop a reliable survivor curve. In addition to the annual renewal quantities

[27] Note that clearance violations are not represented in the asset health chart.

determined from the Repex model we have identified an additional 225 conductor spans for replacement, on the basis that they do not comply with the ground clearances specified in ECP34. We intend to resolve these under-clearances during the CPP period.

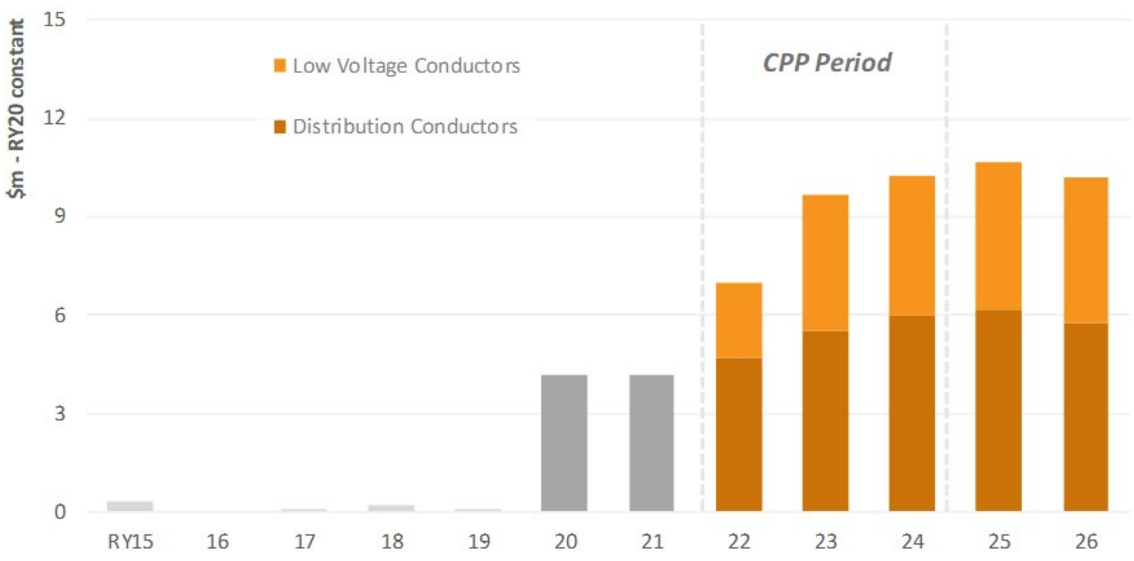
Table 19: Summary of distribution and low voltage conductor approach

Renewal trigger	**Proactive age-based:** we plan to replace distribution conductors based on age relative to expected life, which provides a proxy for conductor condition. Replacements are also prioritized by criticality.
	Under-clearances: overhead line spans that do not have sufficient clearance to ground.
Forecasting approach	**Volumetric forecast** using the Repex methodology and age / expected lives. We plan to replace all 225 under-clearances by RY26.
Cost Estimation	**Historical and estimated costs:** unit rates are based on the average costs of historical distribution conductor replacement works. The unit rate for LV conductor is based on the distribution conductor rate but reduced to reflect efficiencies due to the fact that more live line work can be undertaken. Both unit rates have been reviewed by an external party and are considered reasonable. Unit rates include the costs to replace pole top hardware (i.e. insulators and crossarms) as well as poles that are in poor condition or do not meet the strength requirements to carry the new conductor.

E.7.3. Distribution and Low Voltage Conductor Renewals Capex

397. Figure 51 shows our historical and proposed distribution and LV conductor Capex in the RY15 to RY26 period.

Figure 51: Distribution and low voltage conductors renewals Capex



398. Prior to RY20 our conductor replacements were low, after which we initiated a distribution conductor replacement program. We intend to start our LV conductor renewal programme in RY22. Over the CPP period we intend to increase our expenditure to address poor condition conductors and rectify under-clearances. Our plan shows reduced expenditure post RY26, once we have addressed the under-clearances but will continue at an elevated level compared to historical spend. We do not expect to achieve steady state until RY30.

Box 7: Distribution and low voltage conductors forecast justification

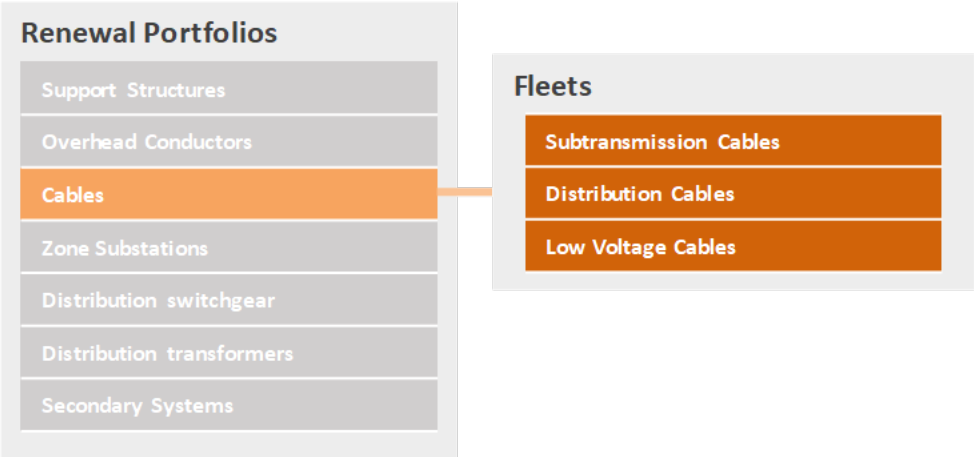
We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: Previously, we have not had a replacement programme for our distribution and LV conductor fleets. Many of our copper and No 8 wire conductors are now in poor condition and are due for replacement. This is partially reflected in the poor performance of our distribution conductor fleet, where there has been a marked increase in conductor drops in the last 5 years. In addition, we have identified conductor span clearances that are not compliant with NZECP34 and are intending to replace these by RY26. Our proposed level of investment will address these needs, improving our overall asset health which in turn will improve performance.
- Cost effective: We are proactively replacing distribution and LV conductors. Planned work of this nature is generally more cost effective than unplanned remediation work.
- Verifier review: our forecasts has been reviewed by the verifier and the forecasts have been considered reasonable without any further changes.
- Review and moderation: our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge. We have deferred non-critical overdue replacements to be addressed by RY30.

E.8. CABLES

400. This section details the cables portfolio investment drivers, forecasting approach and forecast renewals Capex.

Figure 52: Cables portfolio



401. We own approximately 2,200 km of underground cables, which is close to 30% of our total network length. Our subtransmission cable network employs paper lead covered (PILC), gas-filled (GPILC), oil-filled (OPILC), and cross-linked polyethylene (XLPE) cable. Our distribution and low voltage network employs PILC, XLPE and polymer (PVC) insulated cable.

Please refer to AMP chapter 8 for more details on age profiles, quantities and types. All cable expenditure is covered under ID schedule 11a) Asset Replacement and Renewal categories ‘Subtransmission’ and ‘Distribution and LV cables’. Note that the ‘Subtransmission’ category includes both subtransmission cables and conductor fleets.

402. The following sets out our proposed investment on cables during the CPP period and the associated drivers.

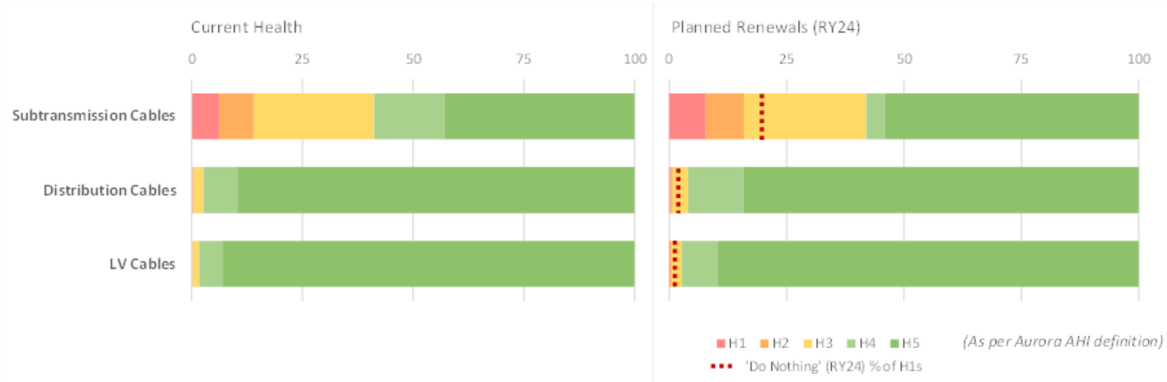
E.8.1. Investment Drivers

403. The following details the main investment drivers for our cables fleet during the CPP period and how they have informed the forecasts.

Condition/Asset Health

404. Figure 53 shows the asset health of our cables fleets.

Figure 53: Cables asset health



405. Our distribution and LV cables fleets are in relatively good condition and we do not anticipate an increase of renewals from historical levels.

406. Old gas-filled cables are a predominant driver for poor health of our subtransmission cable. If we 'do nothing' to address this we predict that our H1-classified subtransmission cables will increase from 6% to 20% over the period to RY24. To prevent this significant reduction in the health of our cables we propose replacing the double circuit, 33 kV, subtransmission cables that supply our Kaikorai Valley and Corstophine zone substations.

407. The 33 kV, gas-filled, cables that supply our Willowbank substation from Transpower's Halfway Bush substation are also due for replacement. However, as part of our growth-related Capex programme (refer to Appendix F) we plan to install a 33 kV cable between our Smith Street and Willowbank substations (coupled with a 33 kV switchboard at Smith Street). This new 33 kV cable forms part of a 33 kV ring network that we are installing in stages to improve the security of supply to the Dunedin CBD and surrounds. The new Smith Street to Willowbank cable will also provide backup supply into the Willowbank substation, allowing us to defer replacement of the Halfway Bush to Willowbank 33 kV cables. The ongoing operation of the Willowbank 33 kV cables contributes to the 8% of H1-classified subtransmission cables we expect to remain in service in RY24.

Historical Cable Performance

408. Figure 54 and Figure 55, below, illustrates the frequency and duration of faults on our subtransmission cable network in the period RY13 to 20.

Figure 54: Subtransmission cable performance frequency of faults

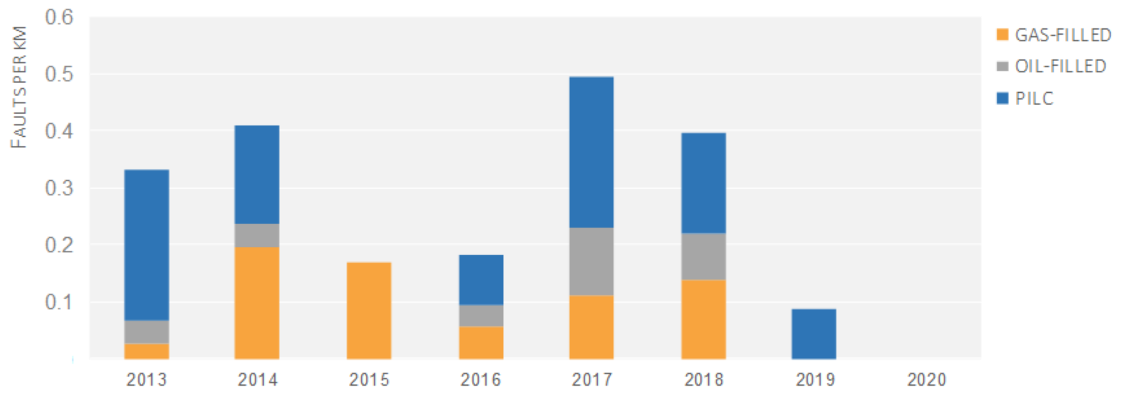
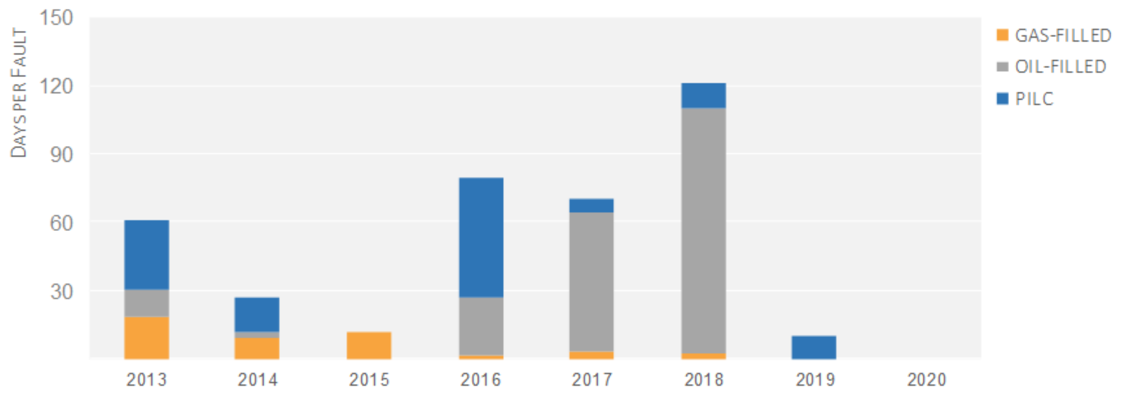


Figure 55: Subtransmission cable performance duration of faults



409. Our subtransmission cable performance has been reasonable in the last two years in comparison to the prior period. There have been minimal interruptions to customers, mainly because most of our subtransmission circuits have n-1 security. However, our analysis shows we are experiencing unusually high failure rates for all types of subtransmission cables, prior to RY19, with incidents occurring almost annually.

410. The failure of our older gas and oil cables is particularly challenging. For example, gas leaks can be difficult/costly to locate, and the joints and termination parts are becoming difficult to source. The condition of the sheath of our oil-filled subtransmission cable is generally acceptable though some minor leaks are of concern – from a sheath continuity perspective, to ensure moisture cannot progress into the cable, rather than the leaking of oil. Also, we have had an issue with an intermittent leak on a cable circuit that we have been unable locate despite significant investigation work (during RY17 / 18). An additional factor is that the qualified gas/oil subtransmission cable workforce is retiring, and with insufficient ongoing training we are finding it more difficult to find competent jointers to repair our oil and gas cables. Our older PILC subtransmission cable (Kaikorai Valley) has

suffered accelerated deterioration due to drying out of the paper below leaking joints installed on steep slopes. This has been the cause of several faults and though it has not reached its expected life, we plan to replace the affected cable in the near term.

Cast Iron Pothead Terminations

411. Prior to the early 1990s, cast iron cable terminations (also known as cast iron potheads) were used to breakout three core PILC cable terminations (also known as cast iron potheads) up poles. These now present a public safety risk in the form of a potential explosive failure mode when re-energising after an outage. This failure mode is age related and caused by moisture ingress. It was highlighted as one of the key risks of the independent network review[28]. We currently manage this risk using re-energisation procedures and have initiated a replacement programme to eliminate this type of termination.

412. A key proactive focus of our cable investment programme is the replacement of all remaining cast iron cable terminations during the period RY22 to RY25.

E.8.2. Forecasting Approach

413. We use a volumetric approach to forecasting renewal Capex for distribution and LV cable assets. The method involves multiplying a unit rate with the forecast replacement quantity, which is established using a Repex approach. Our Repex methodology uses a normal distribution based on cable life expectancy which varies by type. This was used in preference to a survivor curve approach as we do not presently have a large enough sample of condition data to develop a reliable survivor curve. Cast iron pothead terminations are a standalone programme, with all remaining pot heads to be replaced by RY25.

414. We have used an age and condition-based approach to derive the future subtransmission cable replacements. We have developed customised estimates of cable replacement costs for each cable project individually. This considers various factors such as trenching requirements, whether new switchgear is required, traffic management and other costs that may not be captured by a generic volumetric rate.

[28] Aurora Energy – Independent Review of Electricity Networks, by WSP, November 2018

415. Table 20 summarises our forecasting approach for cables.

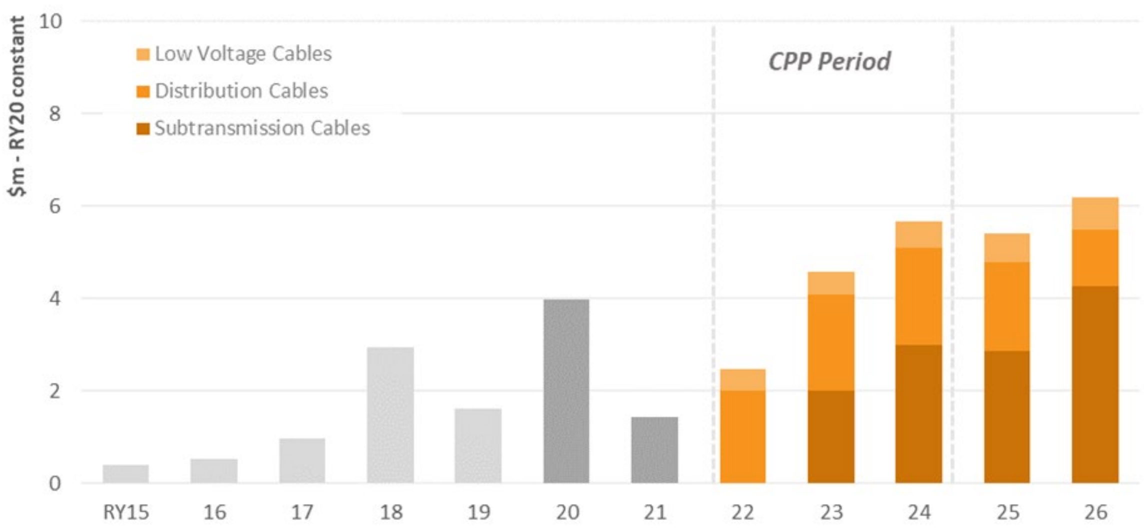
Table 20: Summary of cable approach

Renewal trigger	**Proactive age-based:** we plan to replace cables based on condition. Replacements are also prioritized by criticality.
Forecasting approach	**Volumetric forecast (distribution/LV):** using the Repex methodology and age/ expected lives. **Age and condition-based forecast (subtransmission):** using asset age, expected life and condition factors to develop a forecast. **Specific programme:** all potheads replaced by RY25 due to safety risks.
Cost Estimation	**Historical costs (distribution/LV):** unit rates are based on the average costs of historical cable/pothead replacement works. The costs include all civil and electrical works and cable jointing. **Customised estimate (subtransmission)**: individual capital cost estimates for each cable replacement project.

E.8.3. Cables Renewals Capex

416. Figure 56 shows our historical and proposed underground cable investment in the RY15 to RY26 period.

Figure 56: Cables renewal Capex[29]



29 Our cables investment ramps up from RY22. RY21 is largely focussed on replacement of cast iron pot heads. The risk of cable failure on our Halfway Bush to Willowbank cables is being managed by a resilience project (associated with the new 33kV meshed network architecture) to install a cable between Smith St and Willowbank substations – this work has been deferred slightly to align with recent changes to council related CBD trenching. The moderate levels of risks associated with other 33kV cables did not justify a 'bring forward' into RY21

417. Historically, a significant amount of our underground cables renewal expenditure is related to old gas-filled subtransmission cables in poor condition. The Neville Street gas filled cables were made redundant by the new Carisbrook cables in RY18-19, while the Halfway Bush to Smith Street cables were replaced in RY19-20. Over the CPP period we intend to increase the rate at which we are replacing subtransmission cables and replace the cables that supply our Kaikorai Valley (RY23-24) and Corstorphine (RY25-26) zone substations. Our historical expenditure on distribution cable assets has been relatively low due to the relatively young average age of these assets. However, our elevated forecast expenditure on distribution cable assets provides for replacement of all remaining cast iron pothead cable terminations by RY25.

Box 8: Cables forecast justification

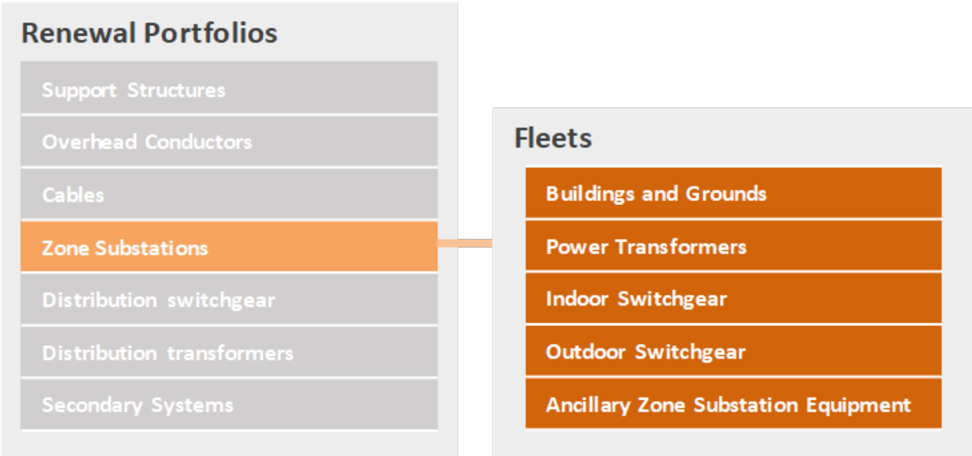
We are confident that our approach delivers an efficient and prudent level of investment because:

- **Clear, prudent drivers:** proposed subtransmission cable replacements involve gas-filled cables that have reached end of life. The risks and failures associated with these types of cables are well documented. Our subtransmission cables supply electricity to zone substations that are the major hubs of our network (each suppling thousands of consumers) and need to be maintained in good condition. The safety risks associated with exploding cast iron pot heads are intolerable.
- **Cost effective:** We proposed to competitively tender the replacement of subtransmission cables. Our proactive approach to replacing cast iron potheads is likely to be cost effective relative to replacing them reactively when they fail.
- **Review and moderation:** our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge. We have deferred low public safety risk cast iron potheads, reflecting delivery constraints, to be replaced by RY25.

E.8.4. Zone Substations

419. The following section describes the key drivers, forecasting approach and forecast renewals Capex for the Zone Substations portfolio. This portfolio covers the fleets shown in Figure 57, below.

Figure 57: Zone substations portfolio



420. Zone substations provide bulk supply of electricity for distribution to many thousands of consumers, relying on a few key assets within each zone substation. The asset types are:

- buildings and grounds. Includes buildings in our zone substations that typically contain protection, communications, indoor switchgear equipment and ripple injection plant. Also includes fences, security and access ways to substation sites.
- power transformers. Includes all power transformers at our zone substations. These range from 2 MVA to 30 MVA and typically have winding voltages of 33/6.6 kV, 33/11 kV and 66/11 kV.
- indoor switchgear. Consists mostly of switchboards that supply our distribution network with a voltage rating of 11 kV or 6.6 kV. A significant proportion of these switchboards comprise old bulk oil or minimum oil circuit breakers. This category also includes a small number of indoor 33 kV switchboards.
- outdoor switchgear. Includes outdoor circuit breakers and switches located in zone substation switchyards.
- ancillary equipment. Includes equipment in zone substations that does not fit into one of the previous categories, for example, load management equipment, outdoor structures, and mobile zone substations.[30]

For more details on asset quantities, types, age profiles and failure modes, please refer to chapter 8 of our AMP. All zone substation expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Zone substations'.

[30] Ancillary equipment also includes some assets that are managed within our Secondary Systems portfolio, including RTUs, DC/AC systems and protection relays.

E.8.5. Investment Drivers

421. Table 21 outlines the main investment drivers for our main zone substation fleets:

Table 21: Zone substation fleet key investment drivers

Fleet	Drivers
Power transformers	**Condition:** ageing fleet with poor condition tap changers and limited spares **Reliability**: equipment failure is rare, however when it occurs, they are costly to repair / replace and may result in prolonged outages
Indoor switchgear	**Condition:** ageing bulk oil and minimum oil circuit breakers, large proportion have exceeded life expectancy **Reliability:** equipment failure resulting in unplanned outages **Safety:** risk of arc flash event (compounded by oil filled circuit breakers), electrocution
Outdoor switchgear	**Condition:** ageing bulk oil and minimum oil circuit breakers, lack of spares to undertake maintenance. We also have indoor switchgear equipment installed in poorly made outdoor enclosures. **Reliability:** The indoor switchgear equipment installed in outdoor enclosures have previously failed, one instance resulting in a switchyard fire and we no longer have spares for some **Safety:** risk of arc flash event (oil filled circuit breakers), electrocution, conductor clearances insufficient

422. We are currently undertaking a seismic reinforcing programme for our buildings expect this to be completed prior to the CPP Period. However, when we undertake replacements of other equipment i.e., indoor switchgear we may need to replace the existing building as part of the indoor switchgear renewal project if it is not sufficient i.e. lacks the required space.

423. We also do not anticipate further ancillary equipment investment for the foreseeable future; however some equipment, such as local service transformers, will be replaced as part of larger zone substation projects.

424. The following sections provide more detail on our investment drivers.

Risk Framework

425. Work in our zone substation portfolio is prioritised using a risk framework that involves the use of risk-based models for the major substation assets (i.e. power transformers and indoor switchgear). The models use specific inputs (e.g. asset age, condition, asset loading) to calculate AHI and criticality. Table 10 outlines the Asset Health and Criticality measures used in the risk framework for each of our power transformers, indoor switchgear and outdoor switchgear fleets.

Table 22: Summary of renewal triggers for the zone substation fleet

<table>
<tr><th colspan="2">Fleet</th><th>Factors considered</th></tr>
<tr><td rowspan="2">Power transformers</td><td>Asset Health</td><td>remaining life based on age and life expectancy
visual inspections of the main tank
visual inspection of the radiators
visual inspection of the tap changer mechanism
number of tap changer operations
oil tests (DP/Furan, dissolved gas analysis and oil condition)</td></tr>
<tr><td>Criticality</td><td>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. backup 11 kV supply from adjacent substations).</td></tr>
<tr><td rowspan="2">Indoor Switchgear</td><td>Asset Health</td><td>remaining life based on age and life expectancy</td></tr>
<tr><td>Criticality</td><td>protection clearing time
equipment fault rating capability in comparison to the actual fault levels
availability of spare parts
consumer load at risk
percentage of load that can be back-fed via other sources</td></tr>
<tr><td>Outdoor Switchgear</td><td>Asset Health</td><td>remaining life based on age and life expectancy</td></tr>
</table>

426. Figure 58 and Figure 59 illustrate risk matrices for our power transformers and indoor switchgear, respectively, as at RY20. We consider the risks in the pink shaded area to be intolerable and have plans to address the assets to which these risks relate. The 'intolerable region' is defined based on a number of factors, including:

- Zone substations are the major hubs of our network and our policy is to proactively replace equipment that is in poor health (i.e. AHI=H1); we do not use a 'run to failure' strategy for zone substation assets.
- We have a lower risk tolerance for assets that play a major part in the successful operation of our network. Given this, it is considered intolerable to retain assets that have a criticality score of C1 once they have AHI scores of H1 or H2.

427. This approach enables us to examine the changes in risk over time, and, to the extent possible, to prioritise zone substation renewal projects. For example, assets that have the highest priority in terms of renewal are located in the top right corner of Figure 58/Figure 59(with a score of H1/C1) and those in the bottom left corner (score H5/C5) do not need to be replaced in the near future.

428. Using our risk framework we can determine which assets that need to be replaced, which are indicated on Figure 58/Figure 59, and the relative priority. We have not extended the risk framework

to our outdoor switchgear, as the majority of the planned outdoor switchgear renewals ‘follow’ power transformer or indoor switchgear projects (i.e. they effectively inherit criticality from either indoor switchgear or power transformer renewals). We intend to develop a criticality framework in the future.

Figure 58: Power transformer risk matrix (RY20)

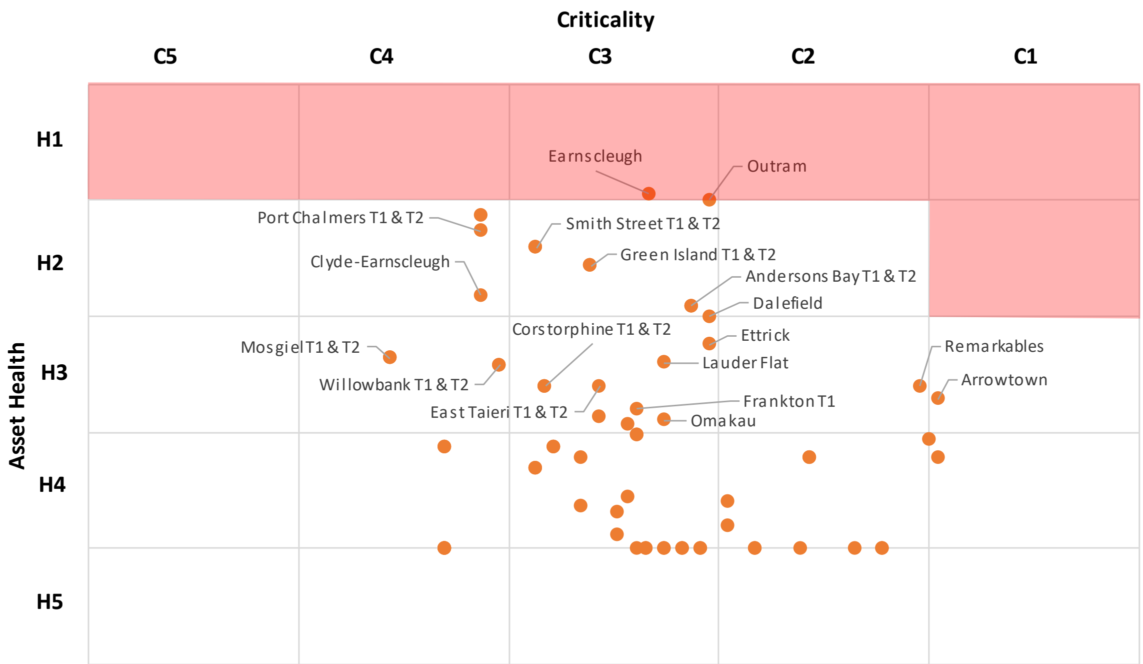
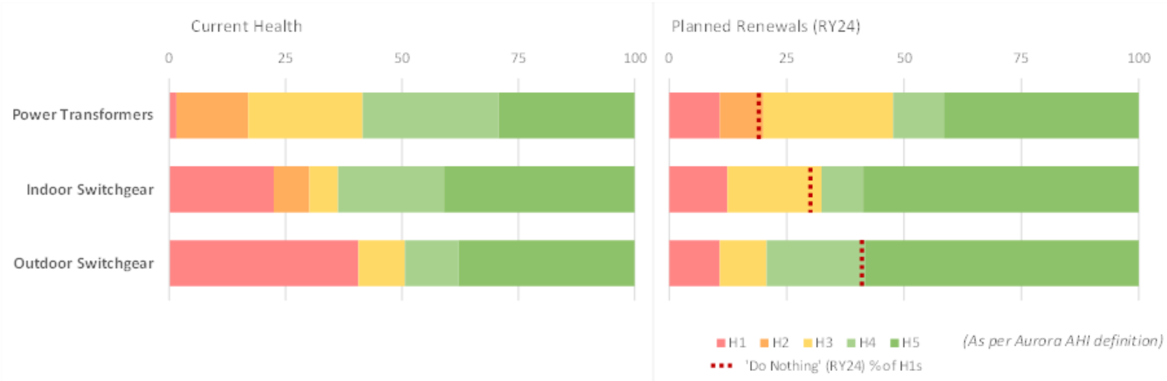


Figure 59: Figure 20: Indoor switchgear risk matrix (RY20)

Asset Health

429. Figure 60 shows the asset health of our zone substation fleets under different scenarios. The left and right columns represent the current health and RY24 health under the planned renewals programme. The dotted line reflects the proportion of H1 assets in RY24 under a 'do nothing' investment programme.

Figure 60: Zone substation asset health



430. A relatively large proportion of our indoor and outdoor switchgear fleet is in poor condition. The main driver for poor indoor switchgear health is the poor condition of the oil filled circuit breakers in the switchgear. Outdoor switchgear also has poor health at present, mainly reflecting poor condition oil-filled circuit breakers and air break switches that have exceeded their expected lives. During the CPP period, many of these will be replaced / removed through outdoor to indoor switchgear conversions and as part of power transformer projects. Our zone substation projects to RY24 aim to reduce H1-classified asset levels down to 12% and 11% for indoor and outdoor switchgear fleets, respectively. This, in turn, reduces associated reliability and safety risks.

431. Our power transformer fleet, while in currently in moderate condition, is ageing quickly. Even with our planned investments, which involve replacement of 5 transformers in the CPP period, asset health continues to deteriorate, with H1 assets increasing to 11% over the period. However, the health of this fleet would decline to a significantly higher level in the absence of any transformer replacements ('do nothing' scenario). Beyond RY24, we intend to continue replacing power transformers to continue to improve overall fleet health, will all H1 graded transformers to be replaced by RY30.

Performance

432. The performance of our zone substation portfolio is closely linked to the following key assets:

- **Power transformers.** Our rate of major/minor failures exceeds most comparable international benchmarks. Over the last 13 years we have had five major power transformer failures at our zone substations.

- **Indoor switchgear.** Indoor circuit breakers are generally reliable assets and we do not have any catastrophic failures on record[31] The WSP review noted the prevalence of indoor oil insulated switchgear involved in outages and that the causes are generally attributed to equipment deterioration/lack of maintenance.[32] The majority of our indoor switchgear is not equipped with arc flash protection and is not arc flash rated.
- **Outdoor switchgear.** We have recently experienced failures of indoor circuit breakers installed in outdoor cubicles. We have also experienced a number of ABS failures due to the breakdown of the cement compound that bonds the insulators to the steel frame of the ABS.

For more details on zone substation performance please refer to chapter 5 of our AMP.

E.8.6. Forecasting Approach

433. We have used the following methodology to forecast zone substations renewal expenditure:

- Determined asset replacement quantities (i.e. power transformers and indoor/outdoor switchgear) based on our risk-based models (discussed above). These renewal ‘triggers’ are summarised in Table 22.
- Grouped renewal needs (i.e. indoor switchgear and power transformer assets) by zone substation, as they will be delivered together as a project.
- Developed specific customised capital cost estimates for each replacement project. In each case we considered the options available and whether like-for-like replacement was sensible. The costs were developed based on itemised equipment lists and our stand price-book unit costs.
- Coordinated renewal projects with growth projects. We also consider factors such as equipment renewal needs that are addressed through growth projects
- We programme both renewal and growth projects, in the same zone substation, to occur in a coordinated manner. The benefits of doing this include a reduction in planned outages as well as a reduction in disruption to local residents (i.e. less construction activity).

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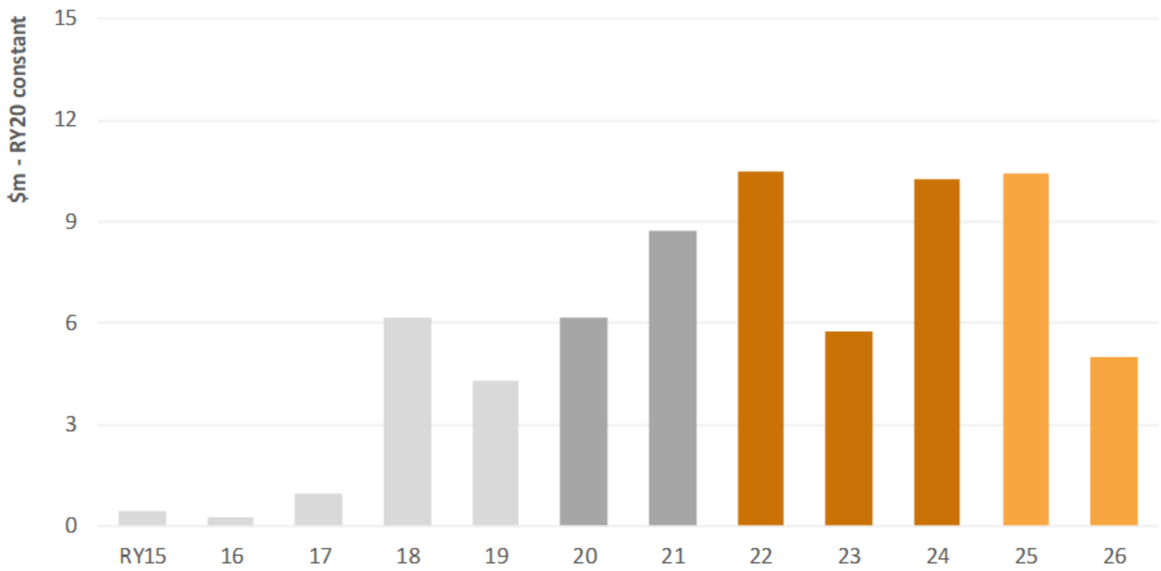
31 Note. Not all projects are shown in RY21 as these have been started prior to the period.

32 Aurora Energy, Independent Network Review, WSP, November 2018.

E.8.7. Zone Substation Renewal Capex

434. Figure 61 shows our historical and proposed zone substation investment in the RY15 to RY26 period.

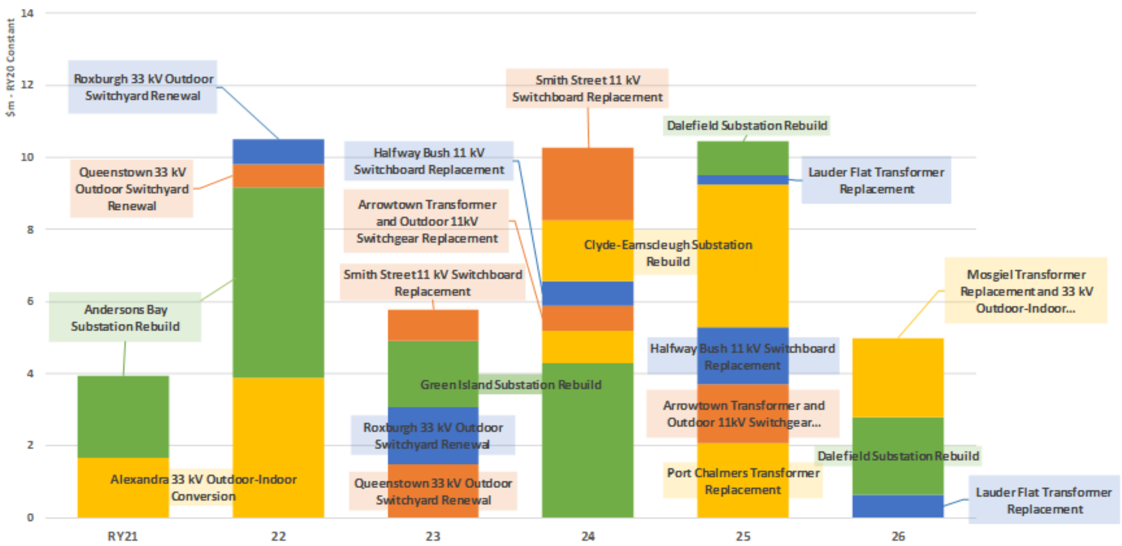
Figure 61: Zone substation renewals Capex



435. Our expenditure on zone substation assets was very low prior to RY18, when we replaced the Neville Street zone substation with the new Carisbrook zone substation. We plan to further increase expenditure during the CPP period in order to undertake the planned works. The expenditure profile is not smooth due to the 'lumpy' nature and relatively high costs of zone substation projects, although we have refined project timings in conjunction with growth projects to manage resourcing levels. Figure 62shows the expenditure that cover the period RY21-26[33] divided up into individual zone substation projects. In most cases the projects span multiple years.

33 Note not all projects are shown in RY21 as these have started prior to the period.

Figure 62: Zone substation projects renewals Capex (RY21 to RY26 period)



Box 9: Zone substation forecast justification

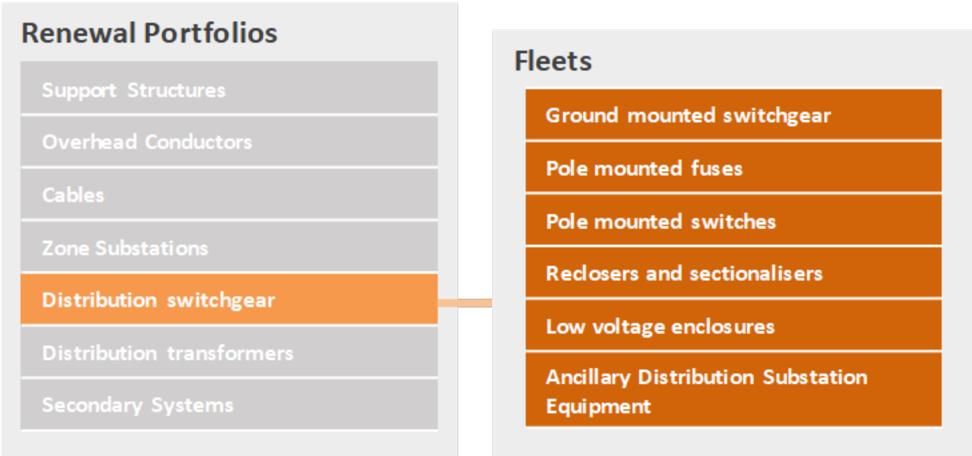
We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: our zone substations are the major hubs of our network (each suppling thousands of consumers). We have experienced a number of equipment failures and a relatively large number of zone substation assets are overdue for replacement. An independent review identified that most of our switchboards do not have arc fault detection and are not rated to withstand an arcing fault. An arcing fault would be a significant hazard that could result in injury and/or a switchboard fire (exacerbated by the oil in our older switchboards).
- Cost effective: in each case we have considered the different options available for renewal (including the 'do nothing option') and we intend to competitively tender our substation renewal projects.
- Verifier review: the zone substation renewal expenditure has been reviewed by the independent verifier and we have incorporated its feedback. We have deferred the South City indoor switchgear renewal project to RY30 as a result of this feedback.
- Review and moderation: our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge. As a result, we have deferred 3 lower criticality projects by 1-2 years.

E.8.8. Distribution Switchgear

437. This section covers the distribution switchgear portfolio investment drivers, forecasting approach and forecast renewals Capex.

Figure 63: Distribution switchgear portfolio



438. The distribution switchgear portfolio comprises the following fleets:

- Ground mounted switchgear comprises of ring main units (RMUs) and single switches. These provide safe network isolation after a fault has occurred or when we need to undertake maintenance activities.
- Pole mounted fuses are protective devices that are located on top of poles and operate after a fault, creating a physical break so that faults are no longer dangerous to the public.
- Pole mounted switches are used to isolate sections of the feeder, so that we may carry out planned or unplanned work. Pole mount switches are located on parts of the feeder such that only a portion of customers will be taken out of service rather than all the customers on the same feeder.
- Reclosers and sectionalisers[34] are used to fulfil a protection function such as automatic isolation and restoration of the network following temporary faults.
- Low voltage enclosures are the main connection interfaces for cable-connected customers. They are simple enclosures that contain fuses that may be located under or above ground.
- Ancillary distribution substation equipment consists of surge arrestors and underground substations, which are underground chambers that may house ring main units, distribution transformers and LV switchgear.

For more details on asset quantities, types, age profiles and failure modes, please refer to AMP chapter 8. All distribution switchgear expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Distribution switchgear'.

[34] We currently do not have any sectionalisers that automatically sectionalise faults after a certain number of fault passages, but plan to install some reclosers for remote switching/sectionalisation purposes.

E.8.9. Investment drivers

439. Table 23 summarises the main investment drivers for each fleet.

Table 23: Distribution switchgear fleet key investment drivers

Fleet	Drivers
Ground mounted switchgear	**Condition and safety:** Our fleet consists of significant volumes of aged, poor condition oil type switchgear. These have been previously identified as having potential explosive failure modes[35] and pose a high safety risk for our workers. Some switchgear is also in areas of the network where high fault currents are experienced, but does not have the modern arc flash safety ratings and barriers. These are also considered a high safety risk for our workers. **Obsolescence**: All our oil filled RMUs except for one type are no longer supported by their manufacturer, meaning genuine parts are no longer available. Furthermore, having populations with small numbers of orphans poses a challenge in terms of maintaining operator competency, and personnel risks associated with operation and maintenance of this switchgear.
Pole mounted fuses	**Condition and operational resilience:** We have a small number of fuses where we have issued a 'do not operate' (DNO) constraint to our workers when undertaking urgent maintenance or prudent renewals. These are either aged, poor condition or suffer from inherent design defects. The DNO constraint requires more of, or the entire feeder to be isolated, affecting more customers.
Pole mounted switches	**Condition:** We have had issues in the field where switches have 'locked up' making them unable to be operated due to physical linkages rusting from corrosion. Like pole mounted fuses, we have had to isolate larger sections of the feeder than would otherwise be required, resulting in larger outages than intended.
Low Voltage enclosures	**Condition:** We have many underground link boxes that have known poor condition issues (leaks / corrosion). These and other LV enclosures have exceeded their expected life and replacement is warranted. **Safety and reliability:** poor condition underground link boxes are unsafe and no longer operated live. The latter mitigates the safety issue but causes a higher outage impact. We have type issues with other LV enclosures where workers have previously been burnt from arc flash energy discharge. Some of these have metallic covers that have the potential to be inadvertently livened creating a public safety hazard.

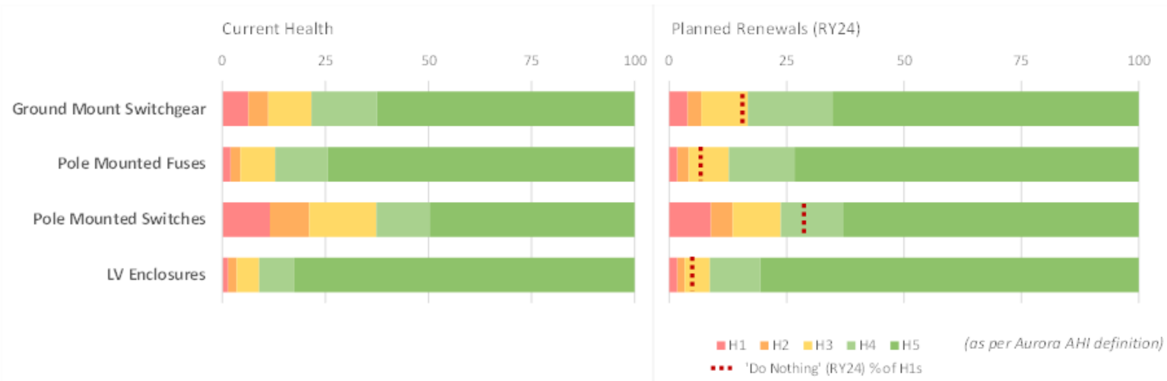
35 Included in the independent network review, undertaken by WSP in November 2018

Fleet	Drivers
Ancillary Distribution Switchgear Equipment	**Condition:** We have previously commissioned an investigation into our underground substations, revealing that much of the equipment inside is in poor condition. **Safety:** There are several safety issues with our underground substations – confined spaces, non-compliance with modern building standards, fire, and arc flash risk. All but one underground substation are considered confined spaces. Any work carried out in these must follow confined space entry procedures. However, many accessways to the underground substation do not meet current building and safety standards. We currently do not have any fire separation, dampers, or air handling in the event of a fire. Many of our HV and LV switchboards in these substations do not have arc flash protection and are a safety risk for our workers.

Asset Health

440. Figure 64shows the distribution switchgear asset health by fleet under different scenarios.

Figure 64: Distribution switchgear asset health



441. The current poor health of some of our ground mounted switchgear is mainly driven by our aged oil filled switchgear (6% of the fleet). Our planned investment will reduce H1 switchgear from 6% to 4% over the CPP period; failing to undertake the investment would allow H1's to rise to 16% of the fleet, presenting an intolerable risk.

442. Some of our pole mounted fuses have reached end of life, but otherwise the fleet is in relatively good condition. However, due to its age, H1 levels will increase from 2% to 7% without investment, affecting our ability to manage/minimise outages and maintain reliability.

443. Pole mounted switches are in the poorest health of our switchgear fleets. Failure to invest would result in 30% of the fleet being classed as H1 in RY24, severely limiting the feasibility of managing the network during outages.

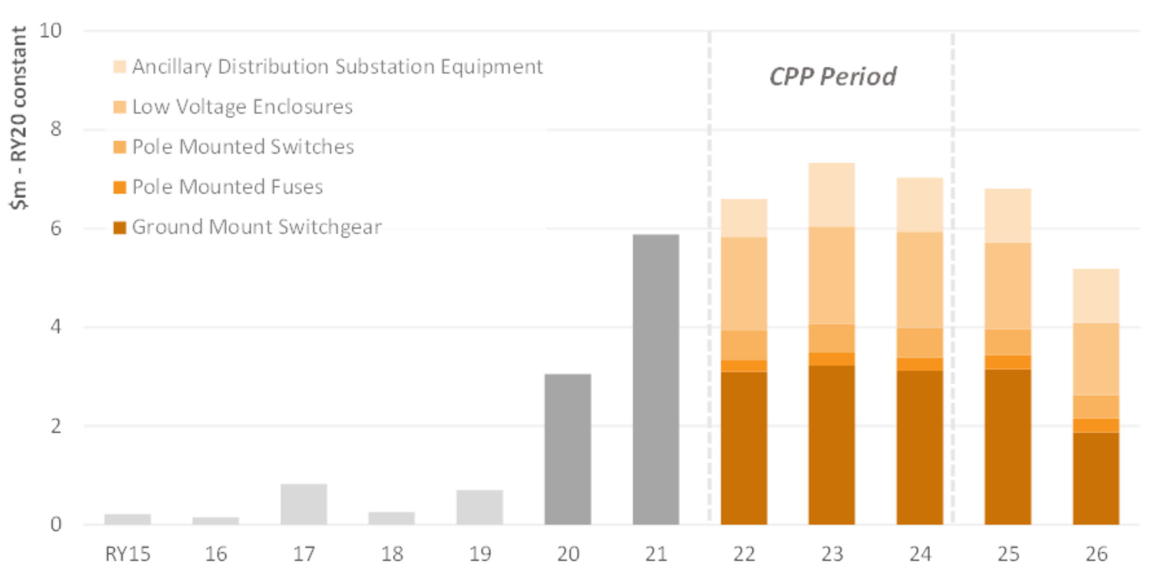
444. Finally, our LV enclosures, overall, are in reasonable condition, with a small number presenting intolerable safety risks. We plan to replace the majority of our underground link boxes during the period to RY26 (due to known poor condition issues), as well as some end of life enclosures.

However, health of this fleet will deteriorate slightly in the short term (as shown in the asset health chart, above) before improving to an acceptable level by the end of RY26.

E.8.10. Distribution Switchgear Renewals Capex

445. Figure 65 shows our Distribution switchgear portfolio historical and forecast renewals Capex by fleet.

Figure 65: Distribution switchgear renewals Capex by fleet



446. Historically, very little proactive renewal investment was undertaken for distribution switchgear. In RY20, we began ramping up our proactive ground mounted switchgear and LV enclosure renewal programmes. We are also replacing some underground substations (Ancillary Distribution Substation Equipment expenditure). This involves either replacing the equipment inside the underground chambers and making them safety compliant or relocating the underground substation to above-ground with new equipment.

447. Over the CPP period, we intend to continue increasing our overall level of investment in distribution switchgear, with a particular focus on replacing poor condition oil filled RMUs and underground link boxes. We aim to replace the majority of our problematic oil filled RMUs by RY25 and underground link boxes by RY24. We plan to replace all our underground substations by RY30, either replacing them in-situ or relocating them above ground where possible.

Box 10: Distribution switchgear forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Clear, prudent drivers:** the distribution switchgear portfolio has several drivers, predominantly condition and safety issues, largely relating to oil filled RMUs, LV enclosures and underground substations. It is critical we continue to invest in these fleets to manage their condition. Failure to do so would result in an increasing renewal backlog and potential safety risks.
- **Cost effective:** we proactively replace equipment when it is found to be in poor condition, which is generally cost effective compared to replacing them reactively. We are looking to competitively tender underground substation renewal projects, due to their relatively high cost and bespoke design of each substation.
- **Verifier review:** our forecasts has been reviewed by the verifier and we have incorporated their feedback. This has resulted in a reduction in expenditure on LV enclosures by adopting a higher expected life.
- **Review and moderation:** our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge.
- **Efficiency:** the LV enclosure replacement unit rate, which is based on recent historical costs, has been reduced by a small percentage from RY22 to reflect efficiency gains from asset management improvements, increased competition amongst our service providers and better works delivery processes.

E.8.11. Forecasting Approach

449. We use a volumetric, Repex approach to forecasting renewal Capex for distribution switchgear, as described in section E.3.2. The method involves multiplying a unit rate with the forecast replacement quantity, which is established using an age based Repex approach that derives the future distribution switchgear replacements. Our methodology uses a normal distribution based on life expectancy which varies by asset type. We have used a Repex methodology instead of a survivor curve approach as we do not presently have a large enough sample of condition data to inform a survivor curve reliably.

450. The forecast is for standalone switchgear replacements. Pole mounted switches or fuses are occasionally replaced (if in poor condition) as part of pole replacements or reconductoring; they are excluded from this forecast and covered under the respective poles / conductor forecasts to avoid double counting. Table 24 shows a summary of our distribution switchgear approach.

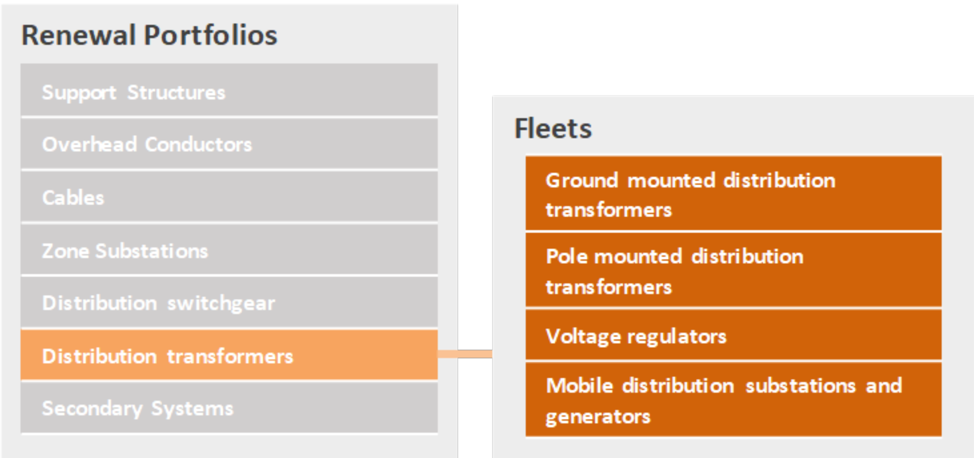
Table 24: Distribution switchgear forecast approach summary

Renewal Trigger	**Proactive condition-based** replacements based on inspection results, identifying poor condition equipment. **Obsolescence** driven replacements for equipment that is no longer supported by manufacturers, lack of spare parts and orphans that require specialists for maintenance / switching.
Forecast approach	**Volumetric** forecast using the Repex methodology and age / expected lives.
Cost Estimation	**Project actual costs** of standalone RMU replacements carried out recently. **Estimated costs** for remaining fleets where these have been reviewed by an external consultant.

E.9. Distribution Transformers

451. This section provides an overview of the distribution transformers portfolio investment drivers, forecast approach and forecast renewals Capex. The distribution transformers portfolio covers the fleets as depicted in Figure 66.

Figure 66: Distribution transformers portfolio



452. We own approximately 7,000 ground and pole mounted distribution transformers, of which approximately 60% are pole mounted. Also included in this portfolio are 13 distribution voltage regulators, three mobile distribution substations and four mobile generators. We also have permanently located standby generators; at six Aurora sites; two of these provide supply to our Cromwell and Dunedin control centres under a loss of supply event and we have a unit at Glenorchy township to increase security of supply should the line supplying the area fault.

Please refer to AMP chapter 8 for more details on age profiles, quantities and types. All ground/pole mounted distribution transformer and voltage regulator expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Distribution substations and transformers'.

453. The following sets out our proposed investment in distribution transformers during the CPP period and the associated drivers.

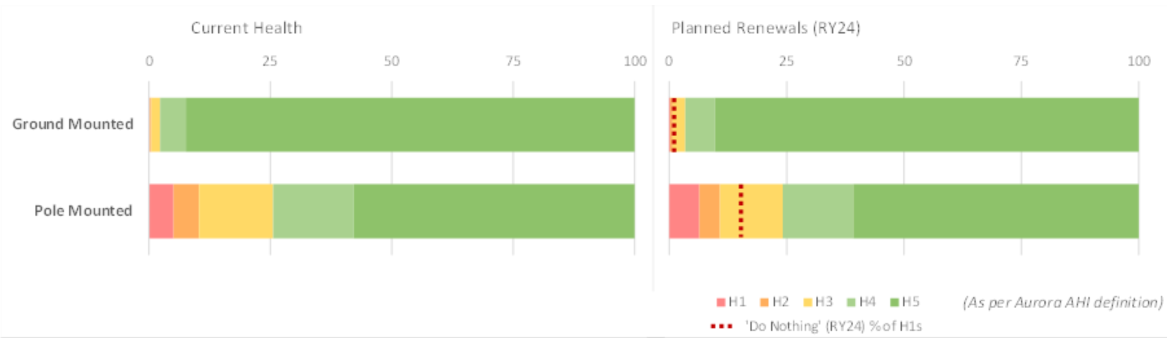
E.9.1. Investment Drivers

454. The main investment drivers for renewal investment in our distribution transformer fleet during the CPP period are asset health and performance. These drivers and how they have informed the forecasts are described below.

Asset Health

455. Figure 67 shows the asset health of our distribution transformer fleets.

Figure 67: Distribution transformer asset health



456. Our ground mounted distribution transformers are in relatively good condition as the fleet is relatively young. On the other hand, about 25% of our pole mounted fleet has already or is expected to reach replacement criteria within the next ten years. Of this, approximately 5% are currently classed H1. Without investment we expect our H1 levels will increase to 16% in RY24. With our planned renewals quantity, we will be able to maintain overall health of the fleet, even as many assets reach replacement criteria during the period.

Condition and Performance

457. The performance of our distribution transformers has generally been good over the past decade. The most common defects involve corrosion of enclosures and radiators and the overloading of transformers can cause power quality breaches and reduce transformer life. Other causes of degradation are third party damage, oil leaks due to surface corrosion of the tank, gasket failure or mechanical failure, and moisture and other contaminants in the oil.

E.9.2. Forecasting Approach

458. We use a volumetric, Repex approach to forecasting renewal Capex for distribution transformers, as described in section E.3.2. The method involves multiplying a unit rate with the forecast replacement quantity, which is established using an age based Repex approach that derives the future distribution transformer replacements. Our methodology uses a normal distribution based on life expectancy. We have used a Repex methodology instead of a survivor curve approach as we do not presently have a large enough sample of condition data to inform a survivor curve reliably.

459. The forecast is for standalone distribution transformer replacements. Pole mounted distribution transformers are occasionally replaced (if in poor condition) as part of pole replacements; they are excluded from this forecast and covered under the poles forecast to avoid double counting.

460. Table 25 summarises our forecasting approach for distribution transformers.

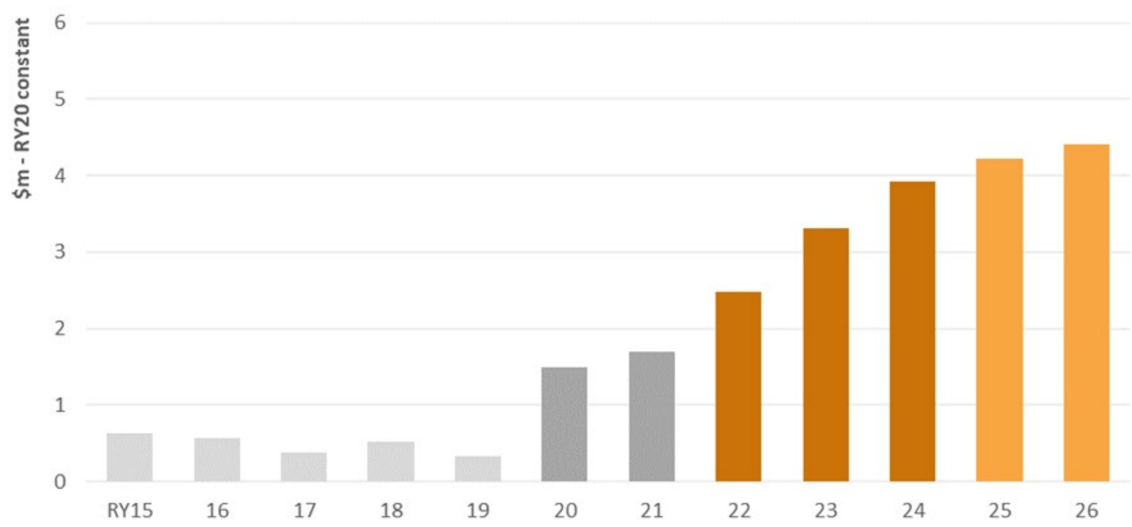
Table 25: Summary of distribution transformer approach

Renewal trigger	**Proactive age-based:** we plan to replace distribution transformers based on condition. Replacements will be prioritized by criticality.
Forecasting approach	**Volumetric forecast:** using the Repex methodology and age / expected lives.
Cost Estimation	**Historical costs:** unit rates are based on the average costs of historical distribution transformer replacement works. Costs include terminating the conductors/cables and also the costs of foundations/pads/brackets.

E.9.3. Distribution Transformer Renewals Capex

461. Figure 67 shows our historical and proposed distribution transformer renewals investment in the RY15 to RY26 period.

Table 26: Distribution transformer renewals Capex



462. Historical expenditure on distribution transformers appears low. This is driven, in part, because over the past five years, a large number of pole transformer renewals have been undertaken as part of our pole renewal programme. There has been little standalone programme spend. We are proposing scaling up our expenditure, mainly on pole mounted distribution transformers, to manage the health of our ageing fleet.

Box 11: Distribution transformer forecast justification

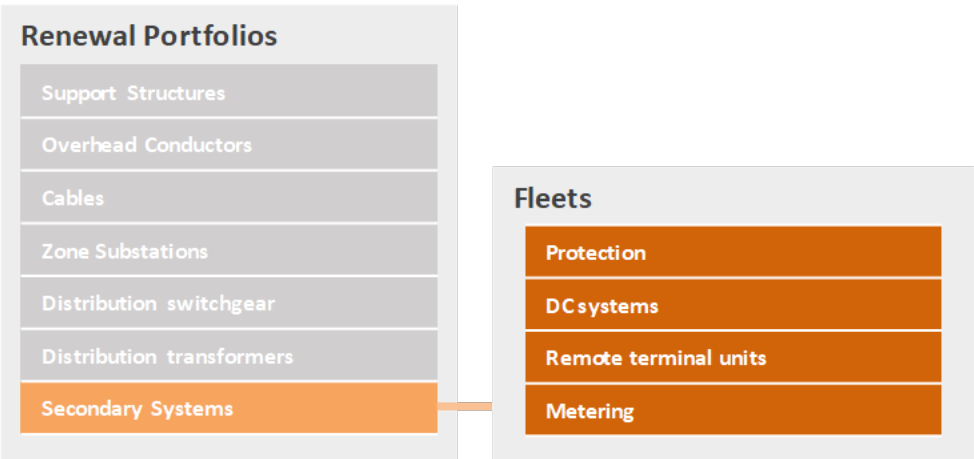
We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: the health of our pole mounted distribution transformers is declining, and a large number of units have already or will soon exceed their expected lives. Due to the age profile of these assets, it is essential that we 'get on top' of this work programme in the short term.
- Cost effective: we have established field service agreements (FSAs) with two new service providers. The FSAs establish contractual mechanisms to manage delivery performance, including financial incentives/penalties and the ability for us to reallocate work or obtain additional capacity if delivery falls short.
- Review and moderation: our forecasts have been reviewed by executive management and the Board, and the forecasts have been moderated to reflect this top down challenge. We have deferred overdue but non-critical pole mounted transformer replacements to be addressed by RY30.

E.9.4. Secondary Systems

464. The following section describes our secondary systems' portfolio investment drivers, forecasting approach and forecast renewals Capex. This portfolio covers the fleets depicted in Figure 68, below.

Figure 68: Secondary systems portfolio



465. Secondary systems are generally located within our zone substations and are critical for the safe and reliable operation of our electricity network. The portfolio encompasses assets that range from

relatively simple to technically complex. They are generally relatively low cost compared to the assets they control or monitor but have shorter expected lives.

466. Our protection fleet comprises approximately 500 protection schemes that are made up of a mix of technology types, with a variety of protection functions. We own approximately 75 battery banks / DC systems that provide a reliable power supply to vital elements within our networks (i.e. protection equipment, SCADA, metering, communications and security alarms). We own approximately 70 Remote Terminal Units (RTUs) that facilitate the control of equipment in our network and the transfer of network information/status. Our metering fleet comprises nine check meters located at Transpower owned substations that supply our networks, and power-quality/revenue metering units at our zone substations.

Please refer to AMP chapter 8 for more details on age profiles, quantities and types. All secondary system expenditure is covered under ID schedule 11a) Asset Replacement and Renewal category 'Zone substations'.

467. The following sets out our proposed renewals investment on secondary systems during the CPP period and the associated drivers.

E.9.5. Investment Drivers

468. The following details the main investment drivers for our secondary systems fleet during the CPP period and how they have informed the forecasts.

Protection Relay Obsolescence

469. Our protection fleet comprises a significant number of legacy type electromechanical relays which provide basic protection functionality. They are at an age where we have concerns about their ongoing reliability, and we are incurring a higher maintenance costs to keep them in service. Lack of spare parts and manufacturer support are also driving obsolescence of these relays and we are facing a lack of technicians with the skills to service electromechanical relays.

Historical Protection Performance

470. There is clear evidence that we are experiencing an increasing number of protection relay maloperation. With regard to electromechanical relays, we are seeing 'drift' (loss of calibration) over time. If relays do fail to operate as intended, this can result in live conductors on the ground not being detected and remaining energised, creating public safety hazards. The WSP review estimated that, over the period RY15-RY18, we experienced fifteen incidents where a conductor fell to the ground and remained live, and which should have been detected by a protection relay. Also, over the last 16 years we have recorded 40 incidents (that have contributed to consumer outages) involving incorrect protection relay settings.

E.9.6. Forecasting Approach

471. We use a volumetric approach to forecasting renewal Capex for secondary systems. This involves multiplying a unit rate by the forecast replacement quantity, where the latter is established using a

simple 'age based' approach. The life expectancy of protection relays is 20 years, for modern/obsolete RTUs is 10 or 15 years and for DC systems with/without redundancy is 8 or 6 years.

472. This forecast comprises standalone secondary systems replacements. Our zone substation projects will replace some poor condition or obsolete secondary system equipment, and we have taken this into account in our secondary system forecasts to avoid duplication.

473. Table 27 summarises our forecasting approach for secondary systems.

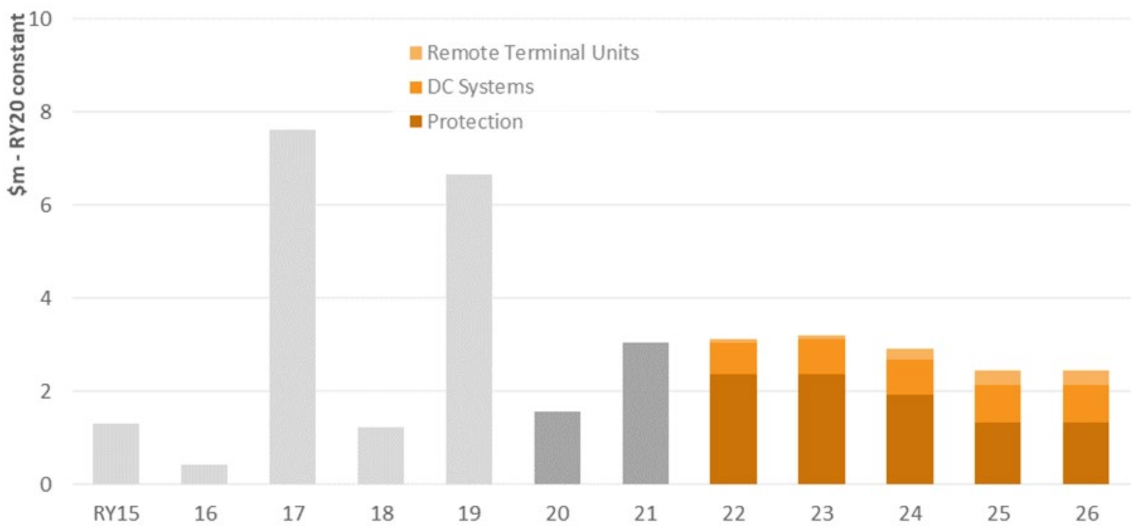
Table 27: Summary of secondary systems approach

Renewal trigger	**Proactive age-based:** we plan to replace secondary systems assets based on age. **Obsolescence and performance:** we are prioritizing our plan to replace all electromechanical relays by RY24.
Forecasting approach	**Volumetric forecast:** using a simple 'age based' methodology and age / expected lives.
Cost Estimation	**Estimated costs:** unit rates are based on the estimated costs that have been reviewed by an independent consultant. The costs include the costs to update SCADA, and to review/update protection relay settings.

E.9.7. Secondary Systems Renewals Capex

474. Figure 69 shows our historical and proposed secondary systems investment in the RY15 to RY26 period.

Figure 69: Secondary systems renewals Capex



475. Our historical expenditure on secondary systems has varied significantly, primarily driven by the large RTU replacement program during RY17-19. Whilst the RTUs are in good condition now, we

have begun to ramp up expenditure on other fleets. We intend to replace all of our electromechanical protection relays by RY24, after which we will continue to replace other types that have reached end-of-life (i.e. static, microprocessor and numerical relays). We expect to have replaced all protection relays that have reached end of life by RY30, at which time our protection relay renewals will have reached steady-state. During the CPP period we also propose to increase our expenditure on DC systems in order to address a large volume of batteries that have reached end of life.

Box 12: Secondary systems forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- Clear, prudent drivers: a significant portion of our fleet of protection relays is obsolete and there is clear evidence that these assets are performing poorly. It is essential that we initiate a significant renewal program to address the safety risk associated with our electromechanical relays. Our planned investment will remove all electromechanical relays by RY24, which aligns with our overarching asset management objectives and safety as a core company value.
- External reviews: our approach and timing are supported by an external review undertaken by WSP in 2018, which found that electromechanical relays were, at that time, the highest risk asset fleet on our network. The review found that our electromechanical relays are at the end of their serviceable lives, and that failure of relays to operate has potentially significant safety consequences.
- Cost effective: We competitively tender the large-scale replacement of protection relays. We have also established field service agreements (FSAs) with two new service providers. The FSAs establish contractual mechanisms to manage delivery performance, including financial incentives/penalties and the ability for us to reallocate work or obtain additional capacity if delivery falls short. In the majority of cases, we intend to undertake multiple relay replacements at a site, for example, the replacement of all electromechanical relays on specific 11 kV switchboards. We have also standardised our zone substation protection schemes via the development of an Aurora Energy standard.
- Verifier review: our protection renewal forecast has been reviewed by the verifier and no further adjustments to the forecast were made.

Appendix F. Growth and Security Capex

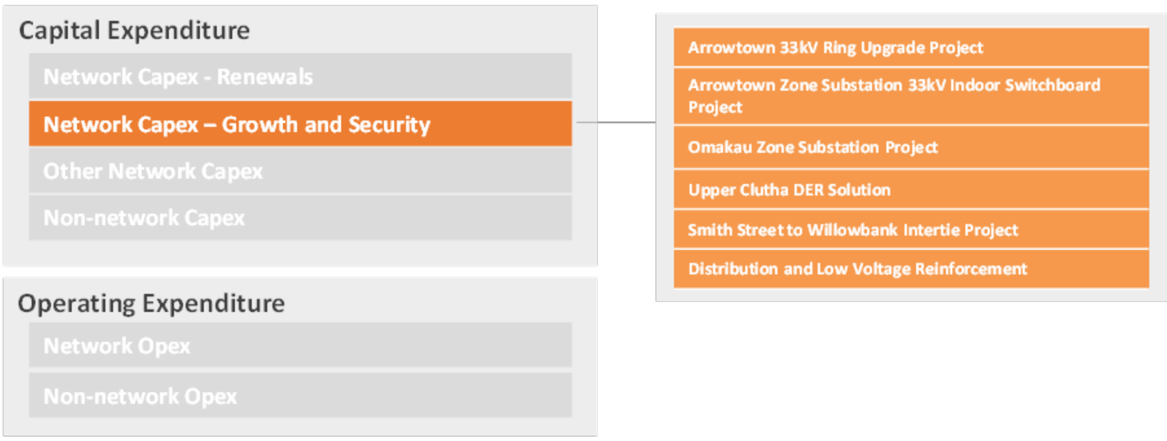
F.1. Introduction

477. This appendix outlines our growth and security capital expenditure, describing our forecasting approach and setting out the drivers for investment. Growth and security investments ensure the capacity of our network is adequate to meet the peak demand of our customers, with appropriate supply security, now and into the future.

478. We expect this to be a significant area of investment in our Central Otago network over the CPP period, driven primarily by increasing ICP numbers and demand. In contrast to our Dunedin network, the Central Otago region continues to experience sustained demand growth, mainly due to residential growth in areas such as Wanaka and Cromwell, as well as commercial growth in Frankton and Queenstown. Our analysis indicates that the peak load on some of our assets is approaching maximum capability and we need to significantly increase our growth and security investments from historical levels.

479. Figure 70 illustrates where growth and security Capex sits within our overall expenditure and the portfolios that make up the category.

Figure 70: Growth and security Capex portfolios[36]



480. As depicted above, the network Capex – growth and security category includes the following expenditure portfolios.

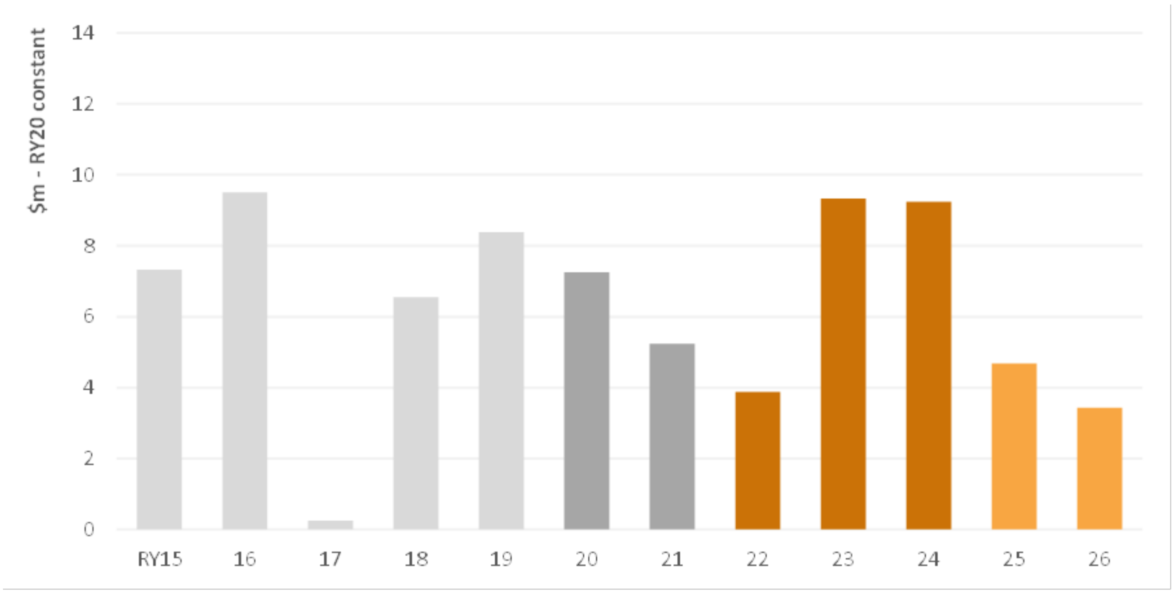
- Major Projects: We treat each major project as a separate portfolio. The projects generally involve zone substations, sub-transmission or GXP related works driven by network security considerations.
- Distribution and Low Voltage Reinforcement: works to ensure adequacy of our distribution feeder assets and LV network.

36 The Upper Clutha DER Solution has been included under non-network Opex as it has a non-network Opex solution.

F.1.1. Expenditure

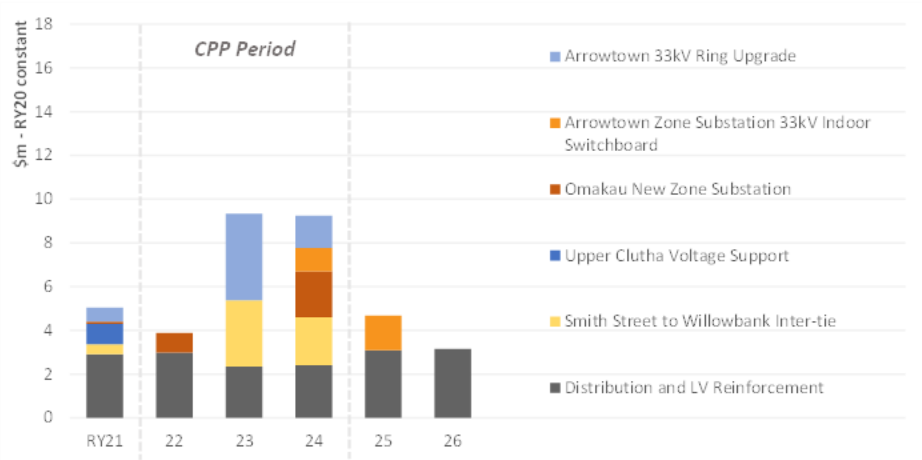
481. Figure 71 sets out our total growth and security Capex for the CPP period together with equivalent historical expenditure.

Figure 71: Proposed growth and security Capex



482. During the CPP period we expect to invest $22.5m in growth and security projects. Major projects are "lumpy " by nature due to the relatively small number of large projects required at specific times to address the identified constraints. Distribution and LV reinforcement has a relatively consistent profile by nature due to the higher volume and lower costs of the projects. Figure 72 has a further breakdown of the forecast expenditure by portfolio.

Figure 72: Forecast expenditure breakdown per portfolio[37]



[37] The Upper Clutha Voltage Support project this RY21 addresses an existing voltage constraint on the Upper Clutha network and is different from the Upper Clutha DER Solution.

F.2. KEY DRIVERS AND FORECASTING APPROACH

F.2.1. Key drivers

483. The driver for our growth and security investments is the need to ensure the capacity of our network is adequate to meet the peak demand of our customers, with appropriate supply security, now and into the future. The three drivers, demand growth, security of supply and power quality, are discussed further in the sections below.

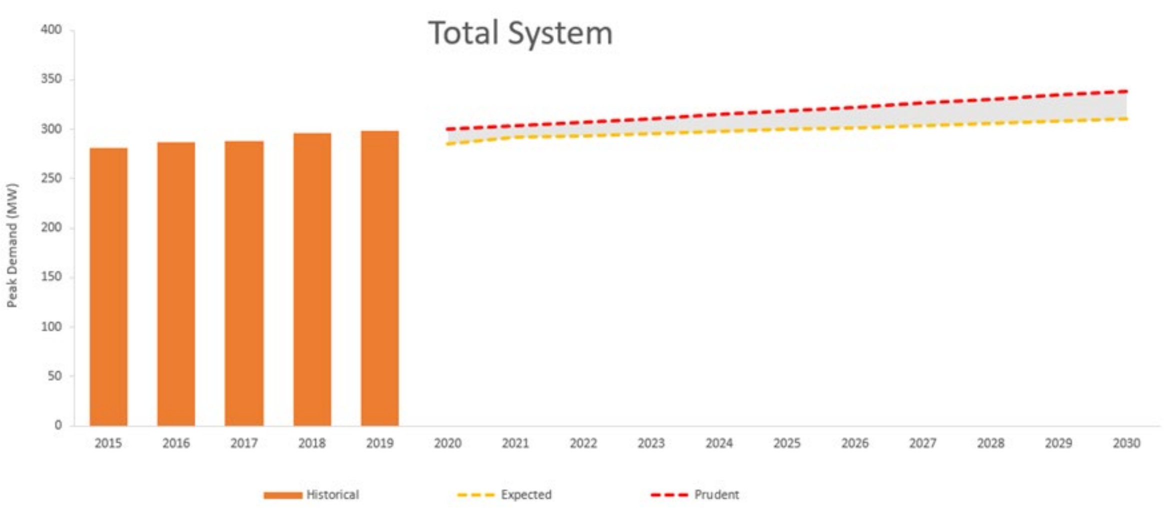
Demand Growth

484. Our projects generally have long lead times and we therefore need to plan for a project well in advance of the need date. To assist in identifying needs in advance, we forecast electricity demand for each of our Zone Substations and GXPs on our network. This demand forecast uses statistical modelling and takes into account the following factors:

- Historical load at Zone Substation and GXP levels
- Population statistics (historical and forecast)
- Gross domestic product (historical and forecast)
- Photovoltaic and Electric Vehicle expected uptake (uses a bass diffusion model)
- Irrigation loads
- Large step changes in load or embedded generation connections.

485. The results from our latest forecasts are shown in Figure 73.

Figure 73: Total network demand – historical and forecast



486. Although our total network demand historical and forecast shows consistent growth, the Dunedin network has seen relatively low levels of historical demand growth and we expect this to continue. The majority of the historical and forecast demand growth can be attributed to the Central Otago network and this will be the major area of investment for the growth and security expenditure category during the CPP period.

Box 13: Covid-19 pandemic

We expect that the Covid-19 pandemic will impact demand over the next two years, especially in the Central Otago and Queenstown lakes areas. This expected impact is not reflected in our demand forecast however we have delayed our Major Projects and forecast a decline in Distribution and LV Reinforcement expenditure in line with this expectation.

Security of Supply

487. Our primary system planning objective is to ensure that there is sufficient capacity to meet customer demand. However, it is also important to ensure that the appropriate level of security is kept on our network. This is about balancing the capital cost of security enhancements with the impact of outages on customers.

488. We have developed security of supply guidelines that are used in conjunction with our demand forecast to help to identify constraints that may have economic solutions. Our security of supply guidelines are used as a guideline only and not set as a deterministic standard.

Power Quality

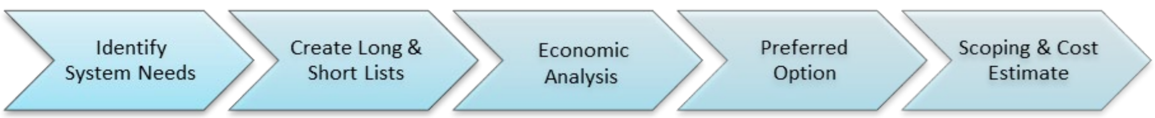
489. Power quality relates to the voltage delivered to the customer's point of supply for the specified load. It covers voltage magnitude, distortion and interference of the wave-form. Targets for voltage levels are specified in Part 3 of the Electricity (Safety) Regulations 2010 and industry standards. We aim to provide quality supply to all customers, within regulatory standards. We do this through good network design, responsiveness to voltage complaints, and active monitoring of load throughout the network.

490. Power quality is generally managed by ensuring that network capacity is adequate. Undersized reticulation or high impedance transformers will increase the risk of power quality issues. Some projects provide for the connection of equipment (for example variable speed drives) which can create high levels of harmonic distortion and it may be necessary to install harmonic filtering equipment to reduce the distortion to acceptable levels.

491. Where new customers are added, our design team may recommend reinforcement of the network. However, most of our work to address power quality issues is reactive, responding to customer complaints. Our plans to increase LV monitoring will enable us to be more proactive in addressing power quality issues.

F.2.2. Forecasting Approach

492. Our growth and security major projects and scheduled distribution reinforcements are forecast on a project by project basis by using the below needs identification and options analysis process.



Identify System Needs

493. We identify possible constraints using our demand forecast model in conjunction with our security of supply guidelines. We systematically analyse the network, using the network load flow model where necessary, and record where demand may breach the security of supply guidelines and the timing of this constraint. Possible solutions to these constraints are then analysed further in the next steps of the process.

Create Long List and Short List of Options (Options Analysis)

494. Following identification of related work a long list of options is identified and documented. The list would typically include the following options:

- "**Do nothing**" – the status quo option.
- **Non-network solutions** such as:
  - Demand side management
  - Energy storage
  - Distributed Generation
- **Network Reinforcement** solutions such as:
  - Installation of reactive support
  - Upgrade of equipment or installation of new equipment
  - Reconfigure the network architecture

495. An initial assessment is undertaken on each of the long listed option to narrow the list down to a short list of credible options for more detailed analysis. The assessment considers:

Table 28: Assessment criteria

Assessment Criteria	Description
Safety	Is the option likely to be meet all health and safety requirements and provide a "safety by design" solution?
Meets the Business Need	Does the option adequately address the business need? (i.e. addresses the identified constraint)
Likely to be Cost Effective	Is the option likely to be cost effective? (i.e. are the costs likely to be commensurate with the risk exposure from not addressing the need?)
Practical to Carry Out	Is the option practical to carry out? This includes from an engineering perspective as well as the legislative requirements of the option (e.g. consenting difficulty)
In Line with Good Industry Practice	Does the option align with good industry practise?

Assessment Criteria	Description
Fit with other planned work	Does the option fit with other planned work on the network?
Fit with applicable strategies	Does the option align with any applicable Aurora strategies?

496. To determine whether the options meets the business need we may need to carry out network load flow studies. The short listing includes assessing whether the "do nothing" case is a viable option. In situations where it is not imperative that we address a constraint, the "do nothing" option is retained as a counterfactual for the short-list analysis.

Economic Analysis

497. Comparison of short-listed options is carried out by considering the whole-of-life costs for each option. It considers three main aspects for each option:

- The capital expenditure
- The probabilistic reliability costs
- Any significant changes in operational expenditure

498. A standard Economic Evaluation template has been developed in MS Excel in order to maintain a consistent approach to the analysis.

Preferred Option

499. We take a number of factors into consideration in selecting a preferred option from the short listed options. The results of economic analysis are a key component, but we also consider:

- The extent to which each option addresses the need
- The risk associated with each option
- Any intangible benefits associated with an option
- An assessment of options against the corporate risk matrix
- How the options fit within the context of our wider asset management objectives (e.g. renewal plans).

500. Selecting a preferred option is not always straightforward and may requires our planning team to apply engineering and economic knowledge. Network development projects need to fit within the context of our wider asset management activities (e.g. renewal plans), such that investments are optimised across all business objectives and constraints. As such, there may be some interaction between potential investments. For example, investments may be brought forward from their need date to enable the work to be integrated with related works. Deferral may also be possible, though this needs to be assessed in each case and may require careful management.

Scope and Cost Estimate

501. Once the preferred option is identified, it is scoped in more detail so that the project costs can be more accurately estimated. This involves an engineering desktop review exercise using drawings, maps and site views (site visits and aerial views) to confirm the work required to complete the project.

502. A standard unit rate list is used to build up the project estimates based on the identified scope. A standard template is utilised that uses these unit rates, this ensures the most up to date unit rates are used and that the costs can be updated with unit rate changes.

503. Following the detailed cost estimate, the economic analysis is revisited to ensure the preferred option still stands with the updated cost estimate. This involves analysing the new estimated cost in the economic analysis and then reviewing the basis for the preferred option choice is still valid.

F.2.3. Inputs and Assumptions

504. The key inputs informing our network development planning analyses are:

- historical demand data, by zone substation and GXP, used for forecasting electricity demand
- information obtained from local councils, developers, irrigators, and other parties reflecting developments expected to impact electricity demand (proxy for economic activity)
- network performance commitments made to customers and stakeholders
- the current configuration of our networks
- manufacturer nameplate ratings, equipment thermal ratings and other factors impacting our equipment ratings
- voltage requirements and other regulated limits.

505. Key assumptions informing our planning are that:

- the uptake of new technology such as electric vehicles, batteries and solar panels will accelerate, but will have only modest network impacts in the planning period
- existing levels of demand side management, including ripple control, are reflected in the historical data and will be reflective of future levels of demand management
- industry rules will remain broadly stable and not lead to step changes in security requirements or levels of distributed generation.

F.3. Arrowtown 33kV Ring Upgrade Project

F.3.1. Project Need

506. Total electricity demand on the Arrowtown 33 kV Ring during 2019 was 15.9 MW which is in excess of the firm capacity of the existing 33 kV lines (13MW).

507. The collective load on the Arrowtown 33 kV Ring is categorised as Z1 so that, according to our security of supply guidelines, consumers should have no interruption for a single cable, line or

transformer fault. At present the Arrowtown 33 kV ring is operated in an open ring configuration and is supplied from Transpower's Frankton (FKN) GXP. The northern leg of the ring supplies our Dalefield and Coronet Peak zone substations, and one of the transformers at our Arrowtown zone substation. The southern leg of the ring supplies our Remarkables zone substation and the second transformer at our Arrowtown zone substation. The Wye Creek hydro generation station injects into the southern leg of the Ring.

508. The open point on the 33 kV ring is at the Arrowtown zone substation using a normally open, manually operated, 33 kV Air Break Switch (ABS) bus coupler. There is a third transformer installed at our Arrowtown substation intended to cater for contingent events; this is connected on the northern leg of the Arrowtown 33 kV ring.

509. Consumer load on the northern leg is dominated by a large commercial ski field (Coronet Peak) and residential/commercial load on the Arrowtown and Dalefield zone substations. Consumer connections on the southern leg include a large commercial ski field (Remarkables), a small hydro generation station (Wye Creek) and residential/commercial load on the Arrowtown substation.

510. A significant number of the conductors on the northern leg of the ring (between Frankton and Coronet Peak) are relatively small; they have a continuous rating of 13 MVA.

511. Additional capacity and improved security of supply is required on the Arrowtown 33 kV ring to securely meet existing and forecast demand

F.3.2. Shortlisted Options

512. To address the capacity constraint on the Arrowtown Ring the following options were shortlisted:

- **Status Quo:** This option is to do nothing other than react when a failure occurs
- **New 33kV Circuit – Frankton to Coronet Peak:** This option involves installing a new 33kV circuit from Transpower's Frankton GXP to a location relatively close to the Coronet Peak zone substation. The new circuit would be underground and would terminate onto a new automated Ring Main Unit (RMU). The new feeder would provide an alternative supply when the 33kV circuit supplying the northern leg is out of service and would be capable of supplying the southern leg during a contingent event.
- **Upgrade 33kV Conductors:** This option involves upgrading the underground cables and overhead lines on the existing northern leg of the Arrowtown 33kV Ring to supply 34 MVA (presently 13 MVA). It also includes installation of automated 33kV switches at strategic locations to enable swift isolation of line/cable sections and faster restoration of power to consumers.

F.3.3. Project Solution

513. The preferred option is to install a third feeder from the Frankton GXP to a new RMU located relatively close to the Coronet Peak zone substation.

514. The demand for electricity on the Arrowtown ring has increased steadily in which the peak demand has exceeded its firm capacity more than six years ago. The peak demand occurs during winter, the

time in which the need for electric heating is at its highest. We expect that the electrical demand on the Arrowtown ring will to continue to increase, which will, increase the duration of unplanned outages.

515. A fault on a section of the line or an equipment failure would place one leg of the Arrowtown ring out of service. When an unplanned outage event occurs during winter, a significant number of consumers (close to 1600 ICPs) will experience a prolonged outage at sub-zero temperatures. Winter conditions can also impede the ability of our service providers to repair faults quickly, leading to an extended outage duration.

516. In the event that consumers are subjected to a prolonged winter outage we expect it will attract significant stakeholder attention, including the media, particularly given the local mayor has advised us to stay on top of growth in the region and the public knowledge that our low levels of investment from previous years has led to the recent fine of $4,977,200 imposed by the High Court (for breaching network quality standards). A prolonged winter outage on the Arrowtown ring would have a significant negative effect on our reputation and stakeholders confidence and we therefore do not believe that the "do nothing" approach is sensible.

517. The two short listed options are not "equivalent". Upgrading the existing conductors has the potential to involve a long-protracted negotiation with landowners regarding the upgrade of the existing 33kV overhead line at significant cost for easement compensations. The preferred option involves the installation of a cable in the road reserve which is "a permitted activity" (local council rules). Further, it also delivers an additional level of security into the Arrowtown ring that will enable maintenance/renewal work to be undertaken on the existing Frankton- -Coronet Peak 33kV overhead line.

518. This project will deliver a switched N-1 supply capacity to the Arrowtown Ring, significantly improving security of supply to the area.

519. The forecast expenditure for this project is shown in Table 29.

Table 29: Arrowtown 33kV ring upgrade project forecast expenditure

NZ$ (m) Constant 2020	RY21	RY22	RY23	RY24	RY25	RY26	RY27+
Capex	0.6	-	3.9	1.5	-	-	-

Box 14: Covid-19 Impact on Arrowtown 33kV ring upgrade project

We have applied a 1 year delay to the construction of this project due to the Covid-19 pandemic. Although the constraint has already been met, after applying a 2 year delay to the demand growth, we found it more economical to defer this project.

Box 15: Arrowtown 33kV ring upgrade project forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because of the following:

- **Appropriate needs and options analysis process:** Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- **Economic analysis:** Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- **Prudent security of supply guidelines:** We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- **Prudent use of our security of supply guidelines:** Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- **Industry good practice load forecast model:** We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

F.4. Arrowtown Zone Substation 33kV Indoor Switchboard Project

F.4.1. Project Need

521. Although the ring will provide the capacity and enhanced security following the Arrowtown 33kV ring upgrade project, the ring will still not have uninterrupted supply in the event of some faults.

522. There is no protection on the existing 33 kV outdoor bus at Arrowtown and the Arrowtown 33/11 kV power transformers are protected by 33 kV fuses. In the event a fault occurs on the Arrowtown 33 kV ring our contractors have to survey the lines, identify the fault, manually isolate the fault and re-energise the un-faulted sections of the ring to restore supply to consumers. Our protection standard requires power transformers and 33kV bus to be equipped with differential protection. This standard aligns with normal industry practice.

523. Additional security on the ring will be required to securely meet the existing and forecast demand.

F.4.2. Shortlisted Options

524. To address the security constraint and the renewal requirements at the Arrowtown substation the following options were shortlisted:

- **Status quo:** This option is to do nothing other than react when a failure occurs

- **33kV outdoor switchyard:** This option involves installing a new outdoor 33 kV switchyard to replace the existing 33kV bus at the Arrowtown zone substation.
- **33kV indoor switchboard:** This option involves installing a new indoor 33 kV switchboard to replace the existing 33kV bus at the Arrowtown zone substation.

F.4.3. Project Solution

525. Our preferred option is to install a 33 kV indoor switchboard at the Arrowtown zone substation. This option had the lowest net present value from our economic analysis and delivered similar benefits to the outdoor solution.

526. The status quo option had significant associated reliability risk and the existing site is not big enough for a 33 kV outdoor switchyard. Additional land would need to be purchased at significant cost if this option was chosen.

527. This project, in conjunction with the earlier proposed upgrade of the Arrowtown 33 kV Ring, will enable the ring to be operated in a closed loop, significantly improving security of supply on the Arrowtown Ring and delivering a (N-1) no-break supply to the Arrowtown zone substation.

528. The forecast expenditure for this project is shown in Table 30.

Table 30: Arrowtown zone substation 33kV indoor switchboard project forecast expenditure

NZ$ (m) Constant 2020	RY21	RY22	RY23	RY24	RY25	RY26	RY27+
Capex	-	-	-	1.1	1.6	-	-

Box 16: Covid-19 impact on Arrowtown zone substation 33kV indoor switchboard project

We have applied a 1 year delay to this project due to the Covid-19 pandemic. Although the constraint has already been met, after applying a 2 year delay to the demand growth, we found it more economical to defer this project.

Box 17: Arrowtown zone substation 33kV indoor switchboard project forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because of the following:

- **Appropriate needs and options analysis process:** Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- **Economic analysis:** Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- **Prudent security of supply guidelines:** We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- **Prudent use of our security of supply guidelines:** Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- **Industry good practice load forecast model:** We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

F.5. Omakau Zone Substation Project

F.5.1. Project Need

530. The peak load on the single power transformer at our existing Omakau zone substation has reached its capacity, with its high load alarm occurring during summer. We have fitted fans to the transformer's radiators to increase its capacity but as the peak load occurs during summer the fans have not significantly increased the transformer's capacity. It is 52 years of age and, capacity aside, we would expect to replace it by RY29 due to reaching end of life.

531. We have already transferred some of Omakau load to our new Lauder Flat zone substation and there is limited capacity in the 11 kV network to transfer additional load. Lauder Flat and Omakau are both 3 MVA single bank power transformer substations. The 11 kV network backup to Omakau, from Lauder Flat, is limited to ~1.1 MVA and the capacity of the Omakau transformer (with fans) is 3.3 MVA during the summer irrigation season. This gives us a combined capacity of 4.4 MVA across the two substations. The peak load is expected to exceed this value in 2022.

532. In addition, significant renewal work is required at our Omakau substation site, including:

- installation of a 33 kV circuit breaker to replace the existing 33 kV fuses that protect the power transformer. Our protection standard requires the power transformers to be equipped with differential protection.
- replacement of the 47 year old minimum oil 11 kV circuit breaker which is in poor condition.

- replacement of the substation's protection relays and control equipment.
- improvement of the substations earth mat to manage touch and step voltage hazards.

533. The existing Omakau zone substation site has a number of limitations as it is on road reserve and is constrained for space to expand. It is also very close to the Manuherikia river and has a flood risk. There is currently no dedicated place to park our mobile substation when this is required to off-load the substation for maintenance or during unplanned outages.

F.5.2. Shortlisted Options

534. To address the capacity constraint and the renewal requirements at the Omakau substation the following options were shortlisted:

- **Rebuild substation and offload to Lauder Flat:** This option involves rebuilding the substation on the existing site and enhancing the 11kV network between Omakau and Lauder flat.
- **Rebuild substation, offload to Lauder Flat and install a mobile sub parking bay:** This option involves rebuilding the substation on the existing site and enhancing the 11kV network between Omakau and Lauder flat. It also includes the installation of a purpose-built parking bay for our mobile substation at a new site.
- **Construction of a new substation:** This option involves constructing a zone substation with a larger transformer at a new site.
- **Construction of a new substation with strengthened 11kV Interties:** This option involves constructing a zone substation with a larger transformer at a new site and reinforcing the 11kV network between Lauder Flat and Omakau

F.5.3. Project Solution

535. Our preferred option is to rebuild the Omakau zone substation on a new site with a single 7.5 MVA power transformer (ex-Cromwell Substation), a mobile substation parking bay, and a 33 kV circuit breaker on the line to Lauder Flat. We have already purchased a new site for this substation, the original purpose being to install a mobile substation parking bay. This project had the lowest net present value compared with the other options. Very little reliability risk was mitigated by the additional strengthening of the 11kV interties between Lauder Flat and Omakau substations.

536. The forecast expenditure for this project is shown in Table 42.

Table 31: Omakau zone substation project forecast expenditure

NZ$ (m) Constant 2020	RY21	RY22	RY23	RY24	RY25	RY26	RY27+
Capex	0.1	0.9	-	2.1	-	-	-

Box 18: Covid-19 impact on Omakau zone substation project

We have applied a 2 year delay to the construction of this project due to the Covid-19 pandemic as we expect the constraint will not occur until RY24 following the Covid-19 pandemic. We will still carry out the design and planning up front to ensure that the project is ready to go if needed earlier.

Box 19: Omakau zone substation project forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because of the following:

- **Appropriate needs and options analysis process:** Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- **Economic analysis:** Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- **Prudent security of supply guidelines:** We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- **Prudent use of our security of supply guidelines:** Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- **Industry good practice load forecast model:** We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

F.6. Upper Clutha DER Solution

Box 20: Upper Clutha DER solution

The Upper Clutha DER solution is a non-network Opex solution to a growth constraint in the Upper Clutha region, as such we discuss this project further in Appendix I - non-network expenditure.

F.7. Smith Street to Willowbank Intertie Project

F.7.1. Project Need

537. The 33 kV subtransmission cables (gas-filled, oil-filled and paper insulated lead covered) that supply our central Dunedin zone substations are reaching end of life and in the short to medium term we expect to have to replace many of them. Given this, we have reviewed the existing layout of our

Dunedin subtransmission network and considered alternative configurations with the objective of improving network performance and security.

F.7.2. Shortlisted Options

538. In this case the do nothing option was not appropriate as the need to replace the cables is driven by the condition of the cables, therefore we shortlisted the following two options:

- **Replace the cables like-for-like:** This option involves direct replacement of the existing underground 33 kV cables on the dual circuits supplying the existing six zone substations.
- **Replace the cables in a new ring architecture:** This option involves converting the existing radial network into a 33 kV meshed-ring network. It involves a combination of like-for-like replacements and new 33 kV intertie circuits to enable a 33 kV ring architecture for the six inner city Dunedin zone substations.

F.7.3. Project Solution

539. Our investigations have concluded that to improve network security and resilience it would be prudent not to replace the cables in a like-for-like architecture but to transition toward a meshed 33 kV network that includes 33 kV switchboards and intertie cables between zone substations. Our proposed future meshed 33 kV sub-transmission network for Dunedin involves:

- Reducing the number of 33 kV supply cables from each of the GXP substations to zone substations, from six cables to four cables.
- Installing six 33 kV cable interties, that create a "33 kV cable ring" linking six substations that supply the central Dunedin city.
- Installing six 33 kV switchboards

540. The replacement for the existing ~3.1km long, gas-filled, 33 kV cables that supply the Smith Street substation is underway and will be completed in 2021. We propose to install a 33 kV switchboard at our Smith Street substation and a 33 kV cable intertie between the Smith Street and Willowbank substations for the following reasons:

- The project forms part of our future plan for the Dunedin network.
- It manages the risks associated with the ~3.9km long, 33 kV cables that supply our Willowbank substation. (These are gas-filled, 57 years old and in relatively poor condition). With the installation of the 33 kV intertie we are proposing to defer the replacement of the Willowbank 33 kV cables until RY28.

541. The cable route passes close to our North City zone substation. In a future project we plan to divert the 33 kV intertie cable to a new 33 kV switchboard installed at the North City zone substation (to further develop the planned future meshed 33 kV Dunedin subtransmission network).

542. The forecast expenditure for this project is shown in Table 32.

Table 32 : Smith St to Willowbank intertie forecast expenditure

NZ$ (m) Constant 2020	RY21	RY22	RY23	RY24	RY25	RY26	RY27+
Capex	0.5	-	3.0	2.2	-	-	-

Box 21: Covid-19 impact on Smith St to Willowbank intertie

We have applied a 2 year delay to the construction of this project due to the Covid-19 pandemic and aligns the asset renewal plans for the Smith Street substation.

Box 22: Smith St to Willowbank intertie project forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because of the following:

- Appropriate needs and options analysis process: Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- Economic analysis: Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- Prudent security of supply guidelines: We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- Prudent use of our security of supply guidelines: Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- Industry good practice load forecast model: We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

F.8. Distribution and Low Voltage Reinforcement

543. The expenditure in this portfolio reflects work to ensure that the distribution and low voltage network capacity and security is adequate to meet the needs of our customers.

544. The portfolio is split into two categories.

- **Distribution reinforcement:** Distribution growth and security planning aims to ensure that the capacity and voltage profile of 11 kV distribution feeders are adequate to meet the current and future needs of our customers. Distribution reinforcement works allow us to add capacity to existing parts of the feeder network, create additional feeders or back-feed ties, upgrade from 6.6 kV to 11 kV, and install or upgrade voltage regulators. Our ability to forecast distribution reinforcement work diminishes with time and can generally be identified 1-4 years in advance.

- **Low voltage reinforcement:** Low voltage growth and security planning aims to ensure that our low voltage network capacity is adequate to meet the needs of our customers. This category is mostly identified reactively due to the low maturity of modelling of the low voltage network. This reactive process works well in an environment where the underlying electricity usage behaviour is stable. However, in an environment where customers materially change their electricity usage behaviour and there is no requirement to notify us, we will not be able to rely entirely on our reactive process to capture the changes in load. We have planned improvements in our low voltage network visibility and modelling as part of the Network Evolution plan.

F.8.1. Forecasting approach

545. In addition to the below forecasting approach we have reduced the forecast distribution and LV reinforcement expenditure by 20% in RY23 and RY24 due to the expected impacts of Covid-19.

Distribution Reinforcement

546. Distribution reinforcement projects can only generally be identified and planned 1-5 years out. We therefore forecast distribution reinforcement in two ways.

- **Scheduled Projects:** Scheduled projects are individually identified and planned through the needs identification and options analysis process. These projects are summarised in Table 4.
- **Non-Scheduled Projects:** These projects cannot be scheduled because of the time horizon. The projects are similar to the scheduled projects but have not yet been identified and therefore cannot be scoped individually. A trended approach is used to forecast the non-scheduled expenditure. In general we expect to have the same expenditure level on Distribution and LV Reinforcement each year (excluding trend considerations). We have used the average of the RY21-23 years forecast expenditure to trend forward. Emerging technologies will require more spend on the distribution network to address reactive power constraints. We expect an increasing trend of about 2.5% per year as more consumers adopt electric vehicles and solar generation technology. This trend has been added to the above annual trend.

Low Voltage Reinforcement

547. We forecast LV reinforcement Capex of approximately $500k per annum using a trend approach based on historical works.

F.8.2. Distribution and Low Voltage Reinforcement Capex

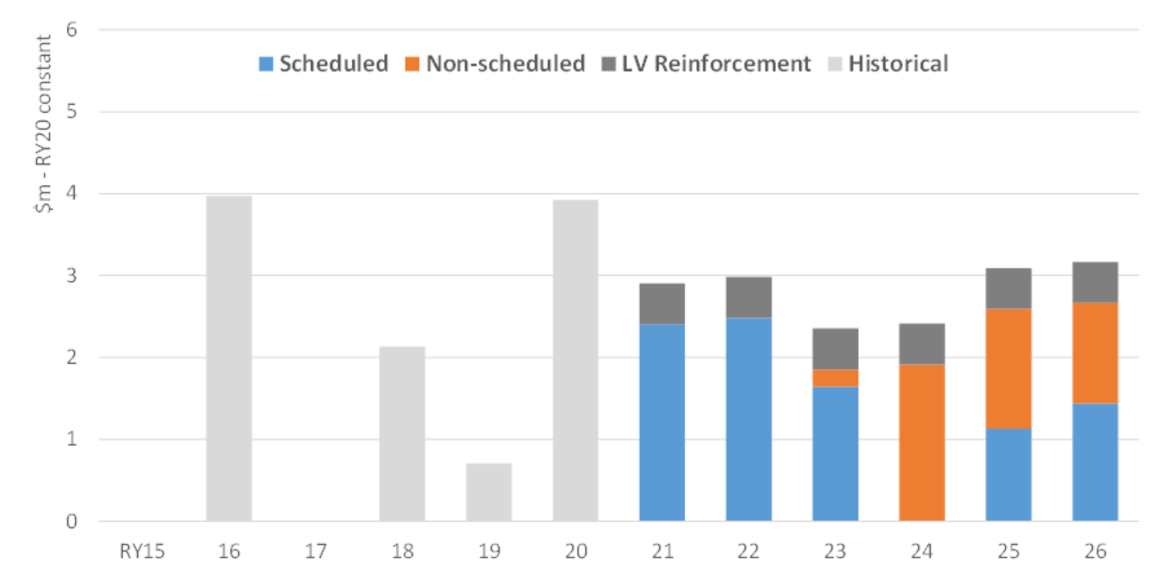
548. Table 33 outlines the current scheduled distribution projects timing and expenditure. The projects scheduled for RY25 and RY26 were previously scheduled earlier, however due to the impact of Covid-19 we expect the need for these will be delayed.

Table 33 : Distribution reinforcement scheduled projects

Project	RY21	RY22	RY23	RY24	RY25	RY26
Extend Ripponvale Road spur to SH6	$0.3m					
Letts Gully and Springvale Road Reinforcements		$1.2m	$1.2m			
Earnscleugh Road Reinforcement					$0.3m	$0.3m
Mutton Town Rd Express Feeder	$0.5m	$0.5m				
Frankton Arm 11kV Cable					$0.2m	$0.6m
New Clyde Township Supply	$0.4m					
New Cardrona 11kV Feeder Cable	$0.3m	$0.8m	$0.5m			
New Commonage 11kV Feeder					$0.7m	$0.6m
Opportunistic work with developers to prepare for future expansion	$0.4m					
Cardrona valley development initial supply	$0.5m					

549. Figure 74 illustrates the historical and forecast expenditure in the distribution and LV reinforcement portfolio.

Figure 74: Distribution and low voltage reinforcement historical and forecast expenditure



550. Points to note:

- The distribution and LV reinforcement portfolio is a newly defined portfolio and therefore historically has not existed. We have been unable to reconcile all of the historical spend against this portfolio and hence the historical view does not accurately reflect the expenditure on distribution and LV reinforcement work.

- The 20% reduction in RY23 and RY24 is due to the expected impact of Covid-19.
- The projects scheduled for RY25 and RY26 were previously scheduled earlier but due to Covid-19 we expect the need for these will be delayed.

Box 23: Covid-19 impact on distribution and LV reinforcement

We have delayed some of the scheduled distribution and LV reinforcement projects due to the expected impact of Covid-19 on demand growth. We also expect to have less non-scheduled work required in the RY23 and RY24 years and have applied a 20% decrease to the forecast expenditure in these years.

Box 24: Distribution and LV reinforcement forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because of the following:

- Appropriate needs and options analysis process: Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- Economic analysis: Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- Prudent security of supply guidelines: We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- Prudent use of our security of supply guidelines: Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- Industry good practice load forecast model: We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

Appendix G. Other Network Capex

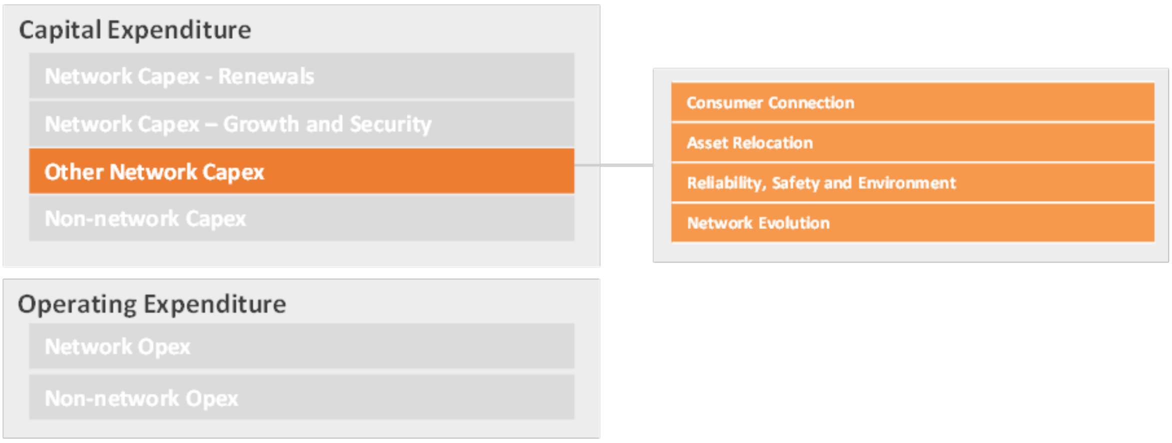
G.1. Introduction

551. This appendix outlines our other network capital expenditure (Other Network Capex), describing our forecasting approach and setting out the drivers for investment. Other Network Capex includes the remainder of our network related Capex outside the renewals and growth categories. It relates to Capex driven by:

- Customer requests for new connections and asset relocations
- Reliability, safety and environment driven work.
- The need to future-proof our network with the introduction of new technology.

552. Figure 75 illustrates where Other Network Capex sits within our overall expenditure and the portfolios that make up the category

Figure 75: Other network Capex portfolios



553. As depicted above, the Other Network Capex category includes the following expenditure portfolios:

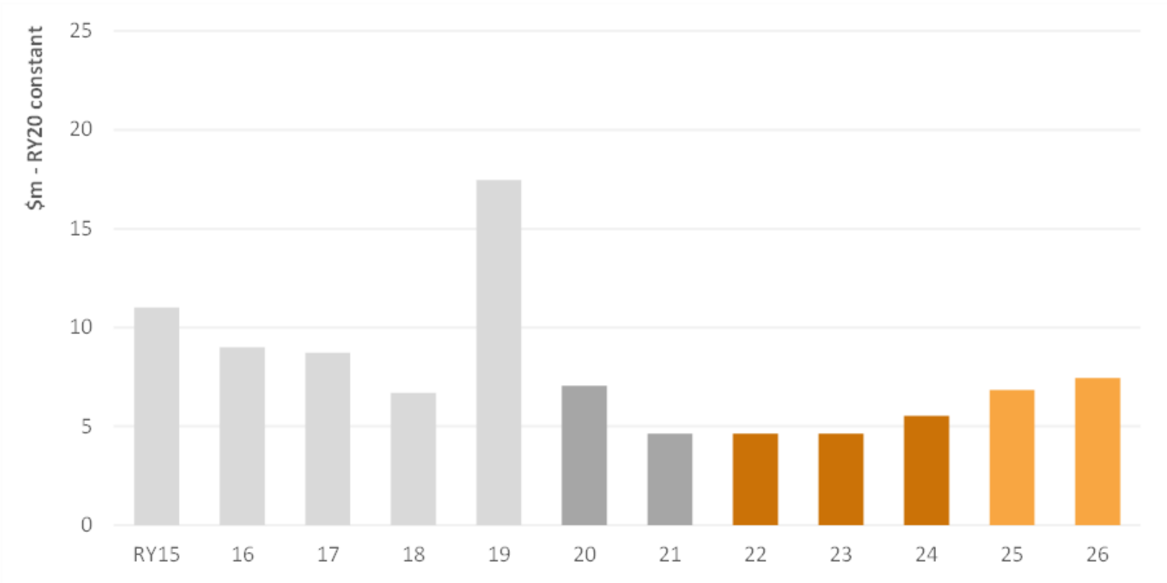
- **Consumer connection:** expenditure on assets where the primary driver is the establishment of a new customer connection point or an alteration to an existing customer connection point. The expenditure is recoverable in total, or in part, by a contribution from the requesting customer.
- **Asset Relocations:** expenditure on assets where the primary driver is the need to relocate assets due to third party requests, such as allowing road widening or similar needs. The expenditure is recoverable in total, or in part, by a contribution from the requesting customer.
- **Reliability, Safety and Environment (RSE):** expenditure on assets where the driver is predominately related to quality of supply, safety or environmental or legislative drivers.

– **Network Evolution:** expenditure to ensure we are prepared for the uptake of new technologies. The CPP focus is the installation of LV monitoring systems to have greater visibility of the LV network.

G.2. Expenditure

554. Figure 76 sets out our Other Network Capex for the CPP period together with the historical expenditure.

Figure 76: Other network Capex historical and forecast expenditure (net of capital contributions)



555. During the CPP period we expect to invest $14.8m in Other Network Capex portfolios. Points to note:

– Consumer connection investments are expected to be lower than historical due to Covid-19 impacts on the economy.

– Asset relocation investments over the CPP Period will be broadly in line with historic expenditure.

– We have included minimal reliability-driven investment over the CPP period in line with our consultation feedback.

– We forecast investment in systems that will help prepare our network for the wider uptake of new technologies.

G.3. Inputs and Assumptions

556. In developing our Other Network Capex forecasts, we have made the following assumptions:

– Average historical connection and relocation volumes are a reasonable predictor of future volumes.

- Assumptions around large customer projects, including timing and cost, reflect our current best estimates and discussions with customers.
- Assumption that an increase in capital contributions to 60% by RY21 is possible as per the current proposed policy amendment.
- No direct spending on reliability improvements are required based on consultation feedback.
- No contingencies have been included in expenditure estimates.
- Covid-19 will cause a lower level of required expenditure in the consumer connections portfolio

G.4. Consumer Connection

557. 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 the new or altered connection point. These assets may provide for either electricity injection or offtake. In general, consumer connection works involve the installation of distribution and low voltage assets. All consumer connections require that customers make a 'capital contribution' as outlined in our capital contributions policy.

G.4.1. Investment Drivers

558. Consumer connection Capex is externally driven (by customer requests) often with short lead times. Historically, we have seen significant year-on-year variation in both consumer connection Capex and capital contribution levels.

559. Volumes of customer connections is largely driven by:

- **Population growth:** the number of new residential properties is driven by population growth, land supply and government policy (for example, Special Housing Areas). These drivers impact both small connection requests, and large subdivision developments.
- **Economic activity:** growth in commercial activity increases the number of commercial/industrial premises that require electricity supply and can also drive a need for increased capacity.

G.4.2. Forecasting Approach

560. We have adopted a trend-based approach that takes account of known large connections when forecasting consumer connection Capex.

561. This involves:

- **Historical Capex trending:** Identification of an appropriate base level of expenditure based on historical spend. This level of expenditure is projected forward. We have adopted the average of the previous 5 years gross expenditure (RY15-19) to trend forward.

- **Trend changes:** An identified upward or downward trend is applied. This is based on external factors that may affect the expenditure in these portfolios. We have not adopted any trend changes following review of projected GDP and population statistics.
- **Identified loads:** Any large known developments or third-party requests are factored into the forecast. For both these portfolios we identify any large projects we are confident will occur and add these to the underlying trend. We have included one possible large connection in the forecast relating to a ski field in the Central Otago region.

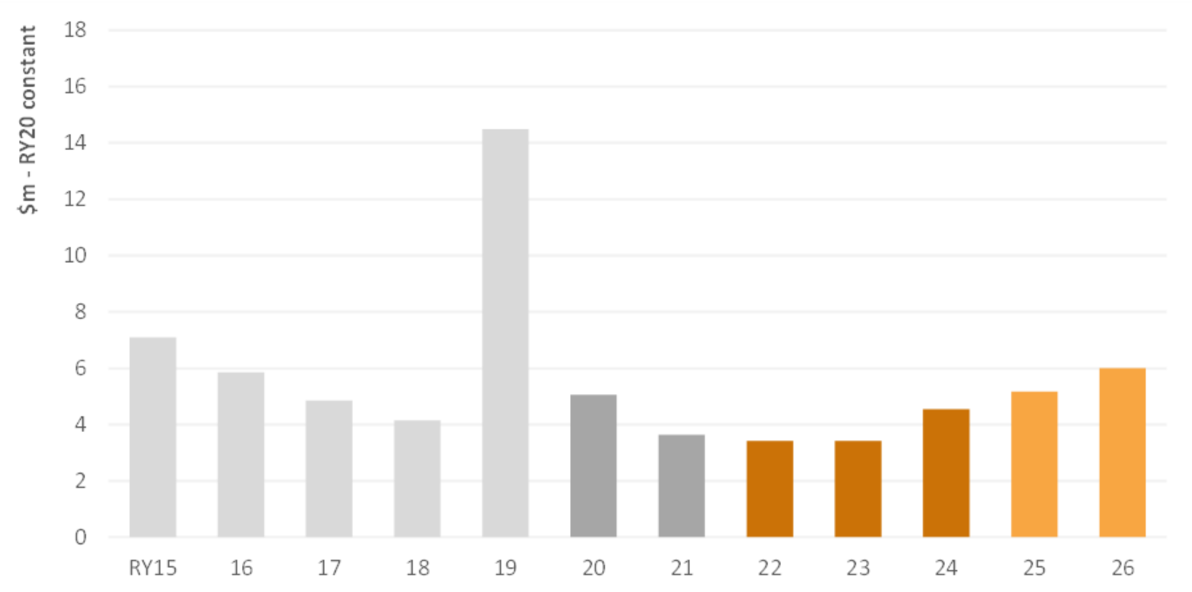
562. We have then applied a contributions rate of 60% to our gross forecast to produce the net forecast figure.

563. We have also made a high level adjustment to the forecast based on our expectation of the Covid-19 impact. We have reduced the forecast expenditure by 20% in RY21 and by 25% in RY22 and RY23.

G.4.3. Consumer Connection Capex

564. Our consumer connections Capex historical and forecast expenditure (net of capital contributions[38]) is shown in Figure 77.

Figure 77: Consumer connection historical and forecast Capex (net of capital contributions)



565. Points to note:

- The expenditure in the RY19 year was a result of an abnormally large number of connection requests and a low capital contributions rate.
- The trend down into RY22-23 and subsequent ramp back up to RY24 is due to the expected Covid-19 impact on the forecast expenditure

[38] Our capital contributions policy is published on our website (https://www.auroraenergy.co.nz/); however readers should be aware that have a review of the policy is scheduled for shortly after submission of our CPP proposal to bring the policy into line with the forecast stated in this CPP Application

– The uplift in RY25 and RY26 is due to the forecast expenditure required on a ski field connection.

Box 25: Consumer connection forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

– Consumer driven: investments are driven by requests from customers, enabling new housing, business expansion, and new developments.

– Contributions level: our capital contributions approach is in line with other EDBs and appropriately balances the cost to be borne by the connecting party and our investment.

– Review and moderation: Our forecasts have been tested and reviewed by executive management and the Board.

G.5. Asset Relocations

567. The asset relocations portfolio includes expenditure on assets where the primary driver is the need to relocate assets due to third party requests, such as to allow road widening or similar needs. This includes expenditure on assets relating to the undergrounding of previously above ground assets at the request of a third party.

568. Asset relocations enable other utility's projects (e.g. NZTA roading works) and are therefore important in facilitating regional growth.

569. The expenditure is recoverable in total, or in part, by a contribution from the customer requesting the relocation. All asset relocations require that customers make a 'capital contribution' as outlined in our Customer Contributions policy.

G.5.1. Investment Drivers

570. Asset relocations Capex is the externally driven by third party requests to carry out relocations required for works such as road widening, at the request of parties such as NZTA.

G.5.2. Forecasting Approach

571. The consumer connection and asset relocations forecasts use a trend based approach due to the recurring nature of the work and due to the fact that these are third-party driven, making it difficult to predict work volumes in terms of quantities.

572. Elements of the approach include

– Historical Capex: Identification of an appropriate level of expenditure based on historical spend. This level of expenditure is projected forward. We have forecast asset relocations using the average of the previous 5 years gross expenditure (RY15-19) to trend forward.

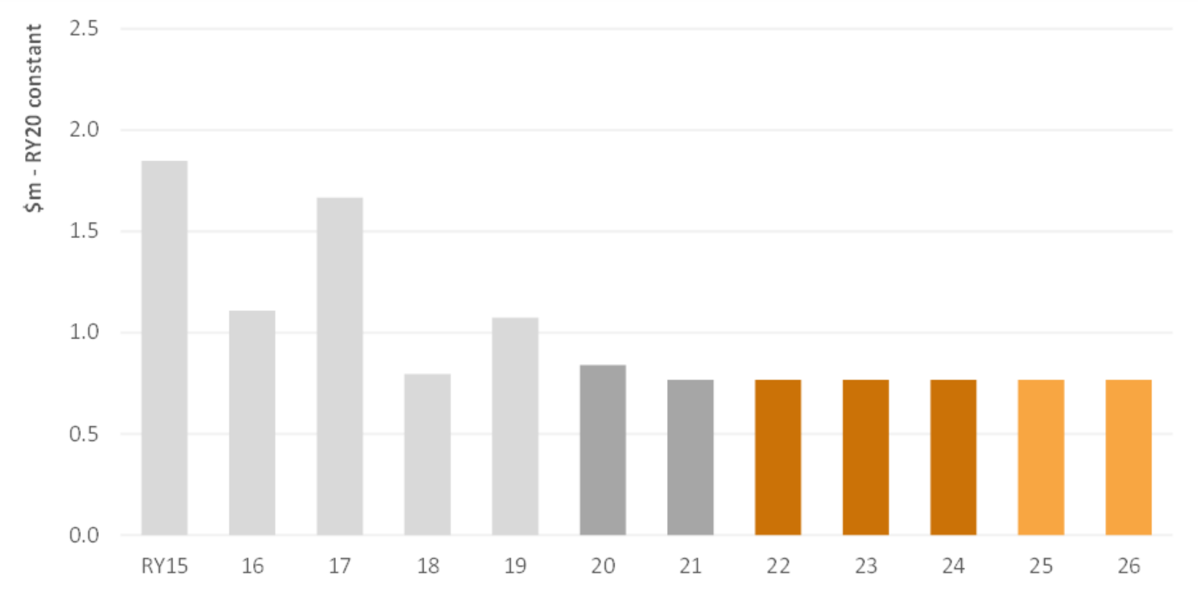
- **Trend changes:** an identified upward or downward trend is applied. This is based on external factors that may affect the expenditure in these portfolios. We have not identified a trend component for the asset relocations portfolio.
- **Point loads or projects:** any large known developments or third-party requests are factored into the forecast. We have no known large relocations included in the forecast.

573. We have then applied a contributions rate of 60% to our gross forecast to produce the net forecast figure.

G.5.3. Asset Relocations Capex

574. Our asset relocations Capex historical and forecast expenditure (net of capital contributions[39]) is shown in Figure 78.

Figure 78: Asset relocations historical and forecast Capex (net of capital contributions)



575. Points to note:

- Historical expenditure has been relatively consistent with some variability between years.
- The forecast asset relocations expenditure is expected to be lower than historical due to the change in our contributions policy and subsequent change in contributions rate.

39 Our capital contributions policy is published on our website (https://www.auroraenergy.co.nz/); however readers should be aware that have a review of the policy scheduled for shortly after submission of our CPP proposal to bring the policy into line with the forecast stated in this CPP Application.

Box 26: Asset relocations forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Externally Driven:** these investments are driven by requests from third parties such as NZTA to enable roading upgrades.
- **Contributions level:** our capital contributions approach is in line with other EDBs and appropriately balances the cost to be borne by the connecting party and our investment.
- **Review and moderation:** Our forecasts have been tested and reviewed by executive management and the Board.

G.6. Reliability, Safety and Environment (RSE)

577. The Reliability, Safety and Environment (RSE) portfolio comprises the following:

- **Quality of Supply (QoS)** – relates to expenditure on new dedicated assets where the primary driver is to meet improved security and/or quality of supply standards. It may target reductions in the overall interruption/fault rate of the network, the average time that consumers are affected by planned interruptions and/or unplanned interruptions, and/or the average number of consumers affected by those interruptions.
- **Legislative and Regulatory** – relates to expenditure on assets where the primary driver is a new regulatory or legal requirement that results in the creation of, or modification to, network assets. We have not forecast any expenditure in this category within the planning period.
- **Other Reliability, Safety and Environment (ORSE)** – relates to expenditure on new dedicated assets where the primary driver is to improve network reliability or safety or to mitigate environmental impacts of the network, where the expenditure is not included in either of the first two categories. For example, this category may include expenditure on assets where the primary driver is to ensure staff safety or meet our environmental policies. We have not forecast any expenditure in this category within the planning period.

G.6.1. Investment Drivers

578. The main driver for our RSE expenditure is where we can identify areas for targeted improvement that will improve our:

- Network reliability
- Safety of our workers and the general public
- Environmental impact from our assets

G.6.2. Forecasting approach

579. The RSE forecast is built bottom-up using a P x Q approach. It includes readily identifiable work within our direct control.

580. Elements of the approach include:

- **Quantity:** Identifying what will be delivered and a projected number of units
- **Price:** Identifying a unit rate for each unit forecast to be delivered

581. The forecast is then simply as sum of the quantities times prices for each unit type.

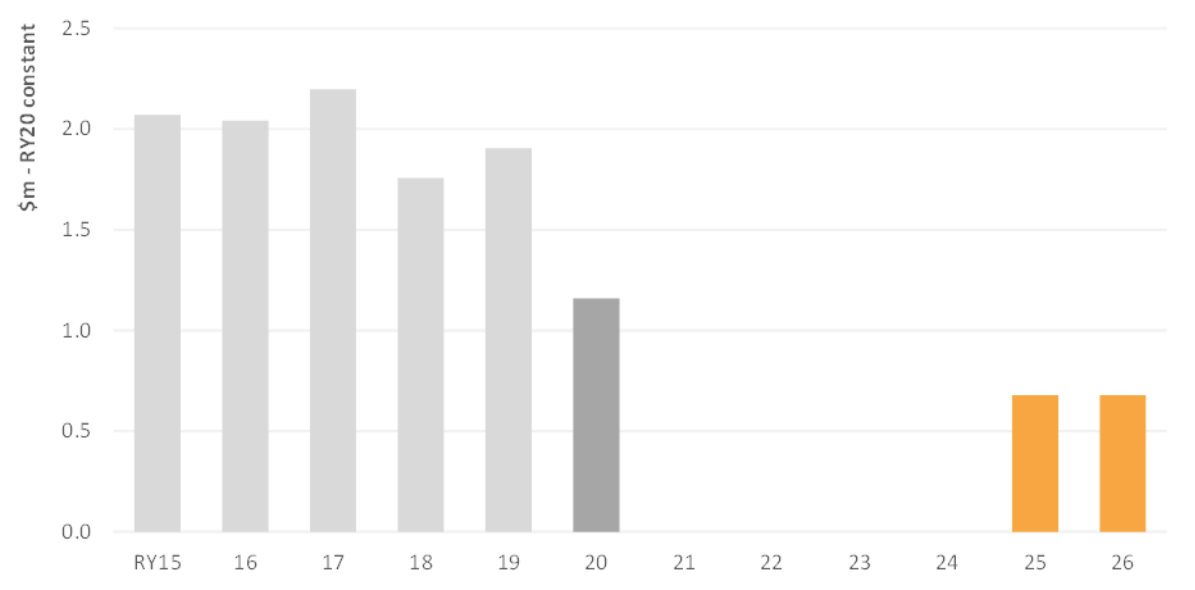
582. We plan to undertake the following QoS initiatives starting later in the CPP period:

- installing strategically placed auto-reclosers on the network to reduce the number of consumers affected by planned/unplanned interruptions
- Installing remote controlled switches on feeders to reduce the average time that consumers are affected by unplanned interruptions
- installing Fault Passage Indicators to reduce the time taken to find faults, reducing the average time consumers are affected by unplanned interruptions

G.6.3. Reliability, Safety and Environment Capex

Our RSE Capex historical and forecast expenditure is shown in Figure 79.

Figure 79: RSE historical and forecast Capex.



583. Points to note:

- We have not forecast any expenditure in the CPP period as a result of the consultation feedback.

– Our step up in RY25 and RY26 is to carry out targeted reliability improvement investments on our network by installing auto reclosers, remote control and fault passage indicators.

Box 27: Reliability, safety and environment forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

– **Clear, prudent drivers:** the planned investments are driven by specifically identified needs, including external targets and mitigation of identified safety, security and environmental risks.

– **Review and moderation:** Our forecasts have been tested and reviewed by executive management and the Board.

G.7. Network Evolution

585. The Network Evolution plan aims to help prepare us for the wider future use of Distributed Energy Resources (DERs). With increased efforts to promote de-carbonisation, we expect to see more electric vehicles, photo voltaic installations and battery storage systems installed on our network.

586. Our network is currently not set up to allow efficient use of these resources and our view is that it is prudent to prepare for this now, rather than react at a later stage. Our investment in this area is focussed on obtaining greater visibility of our LV network so that we can upgrade the network to enable the connection of these resources.

G.7.1. Investment Drivers

587. Investment in Network Evolution is externally driven by the distributed uptake of three main technologies; photo-voltaic generation (solar panels), electric vehicles and storage batteries. Historically there has been little need to have real-time power information for our LV networks as consumer consumption behaviour has largely been predictable and could be catered for when customers connect to our network. These new technologies create uncertainty in consumer behaviour and require us to have greater visibility of our LV network to avoid constraints occurring.

G.7.2. Forecasting Approach

588. The network evolution forecast is built bottom-up using a P x Q approach. It includes readily identifiable work within our direct control.

589. Elements of the approach include:

– **Quantity:** Identifying what will be delivered and a projected number of units

– **Price:** Identifying a unit rate for each unit forecast to be delivered

590. The forecast is then simply as sum of the quantities times prices for each unit type.

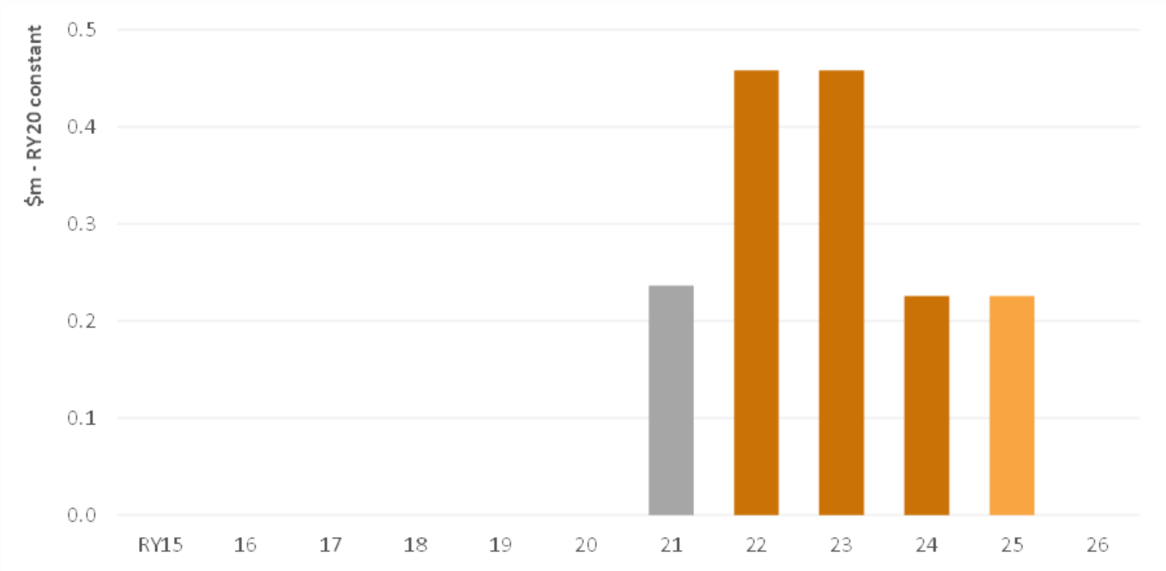
591. We plan to undertake the following initiative in the CPP period:

– **Installation of LV monitoring systems to give greater visibility of our LV networks in constrained locations.** Installation of power quality monitors at appropriate points on each LV network to give indication where a network may be near congestion. These power quality monitors will compliment (not duplicate) data from smart meters where distribution transformer voltage and/or loading data is needed to support data from the LV feeders.

G.7.3. Network Evolution Capex

592. Our network evolution Capex historical and forecast expenditure is shown in Figure 80.

Figure 80: Network evolution historical and forecast Capex.



593. In recent years, our focus has been on network renewal and we have not invested in Network Evolution. We will begin to deploy LV monitoring systems to support connection of distributed energy resources from RY21.

Figure 81: Network evolution forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

– Clear, prudent drivers: the planned investments are driven by the uptake of new technologies. It is more efficient to prepare for these changes proactively rather than reactively responding to issues caused by uptake of new technology.

– Review and moderation: Our forecasts have been tested and reviewed by executive management and the Board.

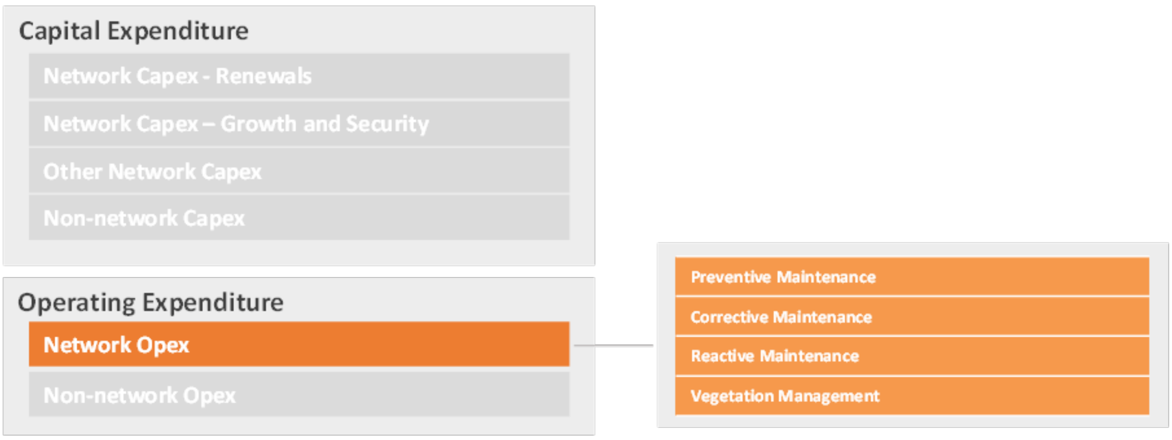
Appendix H. Network Opex

H.1. Introduction

595. Network operational expenditure (network Opex) is essential for delivering our asset management objectives. Appropriate network Opex ensures our assets are operated and maintained appropriately, and that the asset information needed to support effective expenditure in other areas (such as renewals) is obtained.

596. Figure 82 illustrates where network Opex sits within our overall expenditure and the portfolios that make up the category.

Figure 82: Network Opex portfolios



597. As depicted above, the network Opex category includes the following expenditure portfolios:

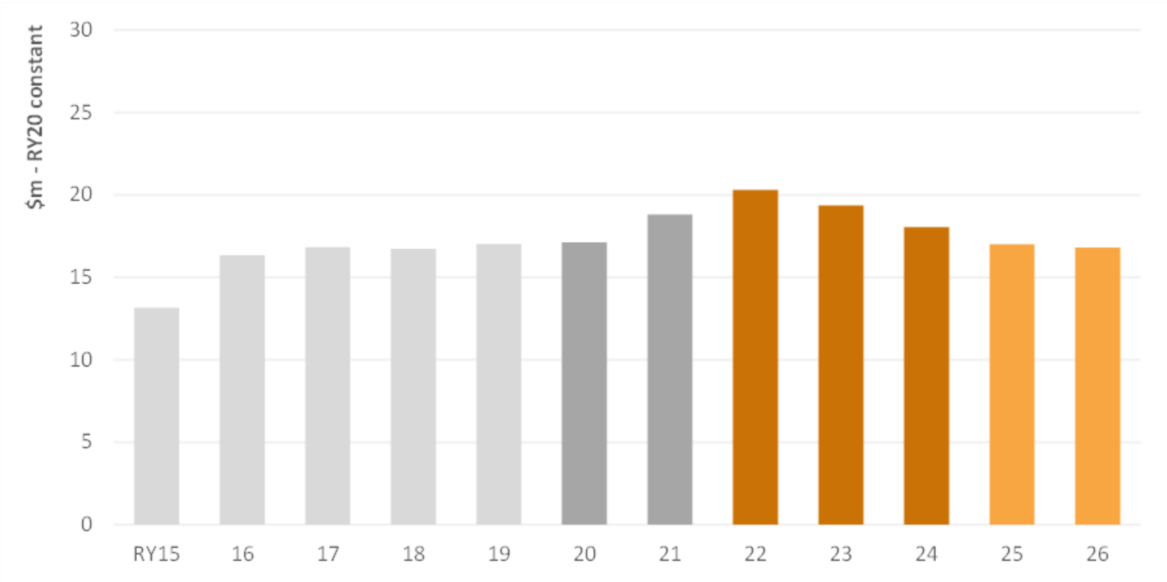
- Preventive Maintenance: routine maintenance activities including testing, inspections, condition assessments and servicing.
- Corrective Maintenance: primarily involves remediating defects, by replacing components or minor assets or undertaking repairs. Corrective work may be identified during preventive maintenance or fault response.
- Reactive Maintenance: responding to faults and other network incidents, this may involve making a situation safe until a full repair is scheduled, or undertaking the repair.
- Vegetation Management: involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of overhead lines and other assets.

For more details on our operations and maintenance activities, please refer to AMP chapter 7.

H.2. Expenditure

598. Figure 83 sets out our network Opex for the CPP period together with the historical expenditure.

Figure 83: Network Opex historical and forecast expenditure



599. During the CPP period we expect to invest $57.7m in network Opex portfolios. Points to note:

- We have historically not completed sufficient preventive and corrective maintenance activities which has led to a need to increase in expenditure in these portfolios during the CPP period.
- Our reactive maintenance expenditure is expected to decrease as overall asset condition begins to improve due to our expenditure in renewals and other network Opex areas.
- Our vegetation management expenditure is broadly in line with historical expenditure and is expected to decrease following the 'first cut' work carried out during the CPP period.

H.3. Preventative Maintenance

600. The preventive maintenance portfolio includes scheduled work to ensure the continued safety and integrity of assets and to compile condition information for subsequent analysis and planning. It is our most regular asset intervention and a key source of information feedback for our asset management approaches. Activities include inspections, condition assessment, servicing and testing.

601. The expenditure in this portfolio reflects preventive maintenance works undertaken by our service providers. It excludes internal staff costs associated with managing the work undertaken by our service providers, which is included in our SONS portfolio.

602. Preventive maintenance is related to our corrective and reactive maintenance activities. We often identify defects during preventive maintenance. An increase in inspections would be expected, to a

point, to increase required levels of corrective maintenance and renewal volumes in the short to medium term.

H.3.1. Investment Drivers

603. The key expenditure drivers for this portfolio are:

- **Asset management system:** we need to gather timely information on assets to make cost effective decisions
- **Legislative or regulatory requirements:** include minimum frequencies for inspecting overhead line assets
- **Maintenance standards** which specify recommended maintenance inspections tasks, servicing intervals and reporting requirements
- **Manufacturers recommendations** around inspections tasks and servicing intervals

H.3.2. Forecasting Approach

604. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

605. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the preventive maintenance portfolio we have used RY19 as the base year and have removed $0.2m of non-recurrent expenditure.
- **Step changes** required to meet the needs of the network or to allow for external requirements. These can be one-off or ongoing changes and involve a change in the scope of work delivered. The step changes for preventive maintenance are outlined in Table 34.
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have applied two trends to the preventive maintenance expenditure
  - **Output growth:** we have relied on the Commission's analysis prepared for the DPP to apply an output growth factor for preventive maintenance.
  - **Efficiency:** we have applied an efficiency trend as outlined in Box 28.

Table 34: Preventive maintenance step-change detail

Step Change Description	Need	CPP total
Pole top / cross arm inspections	Pole tops and crossarms are currently inspected from the ground. Higher quality condition information is available when crossarms are viewed from above, so inspections via camera on a 'hot stick' will be introduced to 5 yearly pole testing	$1.4m

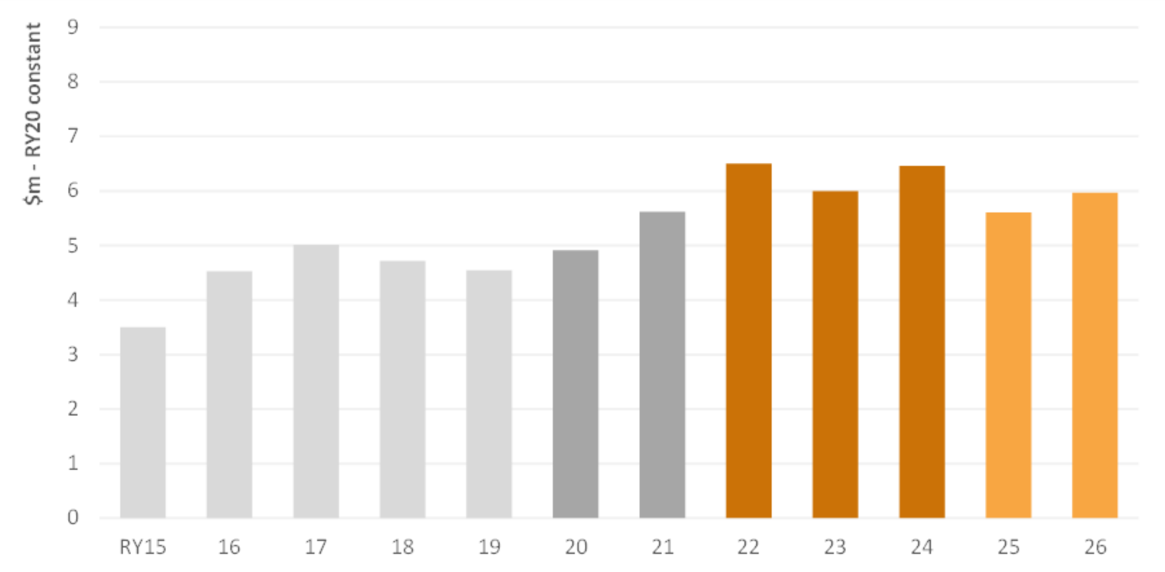
Step Change Description	Need	CPP total
LiDAR survey	Currently we do not have consistent visibility on vegetation and lines clearances. Two yearly lidar (alternating network regions - each network region every four years) will be undertaken to provide quality data, primarily for vegetation management but with future uses in network design and asset management.	$1.0m
Air break switch inspection and maintenance uplift	Historically routine maintenance has not been undertaken on pole mounted switches. It is prudent to restart inspections and servicing to ensure these assets continue to operate as intended.	$0.9m
Consumer owned pole inspections	Based on our estimate of the consumer pole population on our network, consumer pole failures are occurring at a rate almost 10 times higher than Aurora owned pole failures. Inspections need to be undertaken on all consumer poles installed prior to 1984 to ensure they are in a “reasonable standard of maintenance or repair” (per electricity legislation) prior to handover to the consumer. These inspections support consumer pole corrective work	$0.9m
Survey of distribution conductor	At present we do not undertake any detailed, routine conductor survey/inspections. We will start a routine survey of distribution conductor condition, with a focus on fittings and joints condition and type issues following a recent increase in failures. An inspection routine is required to ensure the condition of these enclosures and the public safety risks are managed. Unique asset identifying labels are being attached to the enclosures during inspections.	$0.5m
Low voltage enclosure inspections uplift	Historical base level of inspections was inadequate, we have had incidents reported of electric shock to dogs, and a serious incident with a worker suffering a burnt hand when attempting to open an LV enclosure.	$0.3m
Helicopter inspections of subtransmission lines	Due to the high criticality of subtransmission lines a five yearly helicopter inspection programme will be undertaken to obtain high quality condition information.	$0.3m
Distribution Surge Arrestor inspections	As NERs have been installed on the network, many surge arrestors on the network have become under rated (voltage) and an increase in failures is being experienced. Many surge arrestors are unventilated porcelain which are an explosion hazard in public areas. These inspections are to ensure that no flash overs have occurred, unventilated types are identified, and that the surge arrestor installed is of adequate rating.	$0.1m

Step Change Description	Need	CPP total
Other Minor Step Changes	– Post fault zone substation oil filled circuit breaker servicing. – SF6 management improvements – Poles that have been unable to be tested due to access or traffic management issues – extra work is required to have them tested – Increased maintenance on electromechanical relays – Routine inspections for pole-mounted distribution transformers	$0.2m
Total		$5.6m

H.3.3. Preventive Maintenance Opex

606. Our preventive maintenance historical and forecast expenditure is shown in Figure 84.

Figure 84: Preventive maintenance historical and forecast Opex



607. Points to note:

- Prior to RY19 we didn't complete all our preventive maintenance tasks; these will now be included in future years
- Historically our expenditure varied due to resource constraints
- Our proposed additional maintenance (step-changes) results in an uplift from RY20, ramping up to reach a steady-state level for the CPP period with the exception of the additional two-yearly lidar survey spend.
- The decrease in step changes beyond the CPP period is offset by the trend component of the forecast.

Box 28: Preventive maintenance efficiency adjustment

We have applied specific efficiency adjustment factors to preventive maintenance. There are three areas where we expect to see improved efficiency. The first improvement is in contractor productivity following the increased competitive tension created from our new contracting approach. The second is an improvement in works coordination following the implementation of new outage planning systems and better asset management tools. The third we will be able to improve our decision-making once better data becomes available and better asset management systems are in place. These efficiencies have been applied from RY22.

Box 29: Preventive maintenance forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- Base-step-trend: we have used a forecast technique which is industry good practice for this type of expenditure.
- Clear, prudent drivers: the level of preventive maintenance works undertaken historically has not been adequate resulting in short falls in condition information and less than optimal servicing. Step changes to allow key programmes will ensure that these gaps are addressed and that we will now be able to fully deliver our maintenance specifications.
- Review and moderation: our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been moderated based on feedback and discussion.

H.4. Corrective Maintenance

609. The corrective maintenance portfolio incorporates planned activities arising from defects identified during preventive maintenance work or as follow-up to a fault (after service restoration). Where defects do not require urgent remediation, the work can be prioritised and scheduled, which is generally more cost effective than carrying it out reactively. Failure to undertake this work increases reliability and safety risks and may shorten asset lives. Corrective maintenance does not include replacing complete assets and does not extend an asset's original expected life. As such it is categorised as operating expenditure.

610. The expenditure in this portfolio reflects the cost of corrective maintenance undertaken by our service providers. It excludes internal Aurora Energy staff costs associated with managing the work undertaken by our service providers, which is included in our SONS portfolio.

611. Corrective maintenance is related to our preventive and reactive maintenance activities. Defects are often identified during preventive maintenance (inspections, condition assessments and servicing). Reactive maintenance includes emergency and 'first response' work which focus on making assets safe and where possible, returning them to service promptly. 'Second response' work to return assets or sites to operational condition is classified as corrective maintenance. Increases in reactive works such as those due to adverse weather may also increase the volume of corrective follow up

work. Corrective maintenance work also covers provision of stand over (e.g. third party excavations), and customer costs not driven by customer contributions, such as replacement of consumer service line and poles.

H.4.1. Investment Drivers

612. The key expenditure drivers for this portfolio are:

- **Asset condition:** as identified during preventive maintenance activities and other defect reporting means.
- **Fault numbers:** where assets require second response work
- **Legislative or regulatory requirements.**

613. The volume of work we undertake in other maintenance or renewal portfolios affects corrective maintenance volumes in the longer term. For example, an increase in planned renewal or preventive maintenance work on the overhead network will tend to decrease corrective maintenance volumes (in the longer term) because it improves the condition of assets. However, in the short term, an increase in preventive maintenance may result in more defects being identified. An increase in reactive maintenance work may result in an increase in 'second response' (corrective) work.

H.4.2. Forecasting Approach

614. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

615. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the corrective maintenance portfolio we have used RY19 as the base year.
- **Step changes** required to meet the needs of the network or to allow for external requirements. These can one-off or ongoing changes and involve a change in the scope of work delivered. The step changes for corrective maintenance are outlined in Table 35.
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have applied three trends to the corrective maintenance expenditure
  - **Output growth:** We have relied on the Commission's analysis prepared for the DPP to apply an output growth factor for corrective maintenance
  - **Asset renewal:** We expect to see an increasing rate of improvement from the programme of asset renewal and have estimated a percentage improvement per year.
  - **Efficiency:** We have applied an efficiency trend as outlined in Box 30.

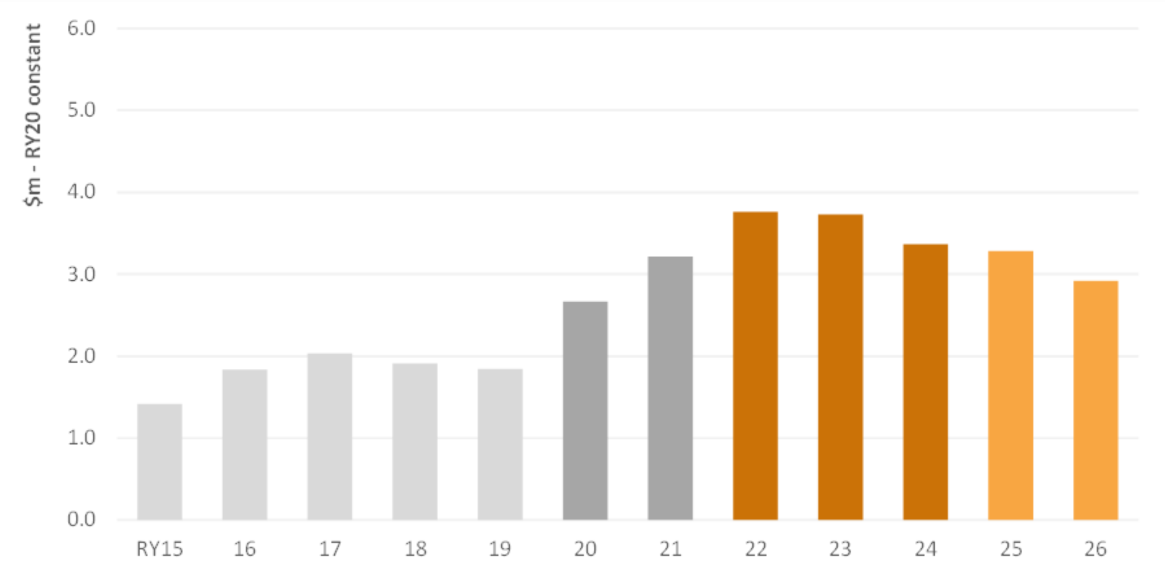
Table 35 : Corrective maintenance step change detail

Step Change Description	Need	CPP total
Consumer pole remediations	Based on our estimate of the consumer pole population on our network, consumer pole failures are occurring at a rate almost 10 times higher than Aurora owned pole failures. Prior to formally handing over consumer poles and conductor installed prior to 1984, the poles and conductor must be in a "reasonable standard of maintenance or repair" (per electricity legislation), and hence remediations are forecast This step change is to cover poles only as the base contains sufficient conductor spend.	$3.3m
Expected new defects	Following the increased focus on preventive maintenance, the number of new defects requiring Opex is expected to increase in the medium term.	$0.6m
Possum guard and cable guard retrofit programme	Inspections on our poles have found that 24% of poles are either missing possum guards or the possum guard is in a state that requires replacement.	$1.0m
Zone substations transformer painting	Transformers older than 20 years in Dunedin that are not being replaced require corrosion control to ensure they last their expected lives.	$0.2m
Distribution assets repainting	Historically no corrosion mitigation has been carried out on distribution assets.	$0.1m
Rectify backlog of cable corrective maintenance	A large backlog of corrective maintenance work has been identified on oil cables from site visits in 2019. Maintenance is primarily corrosion control and fixing oil leaks.	$0.1m
Legacy metal service pillar (LV enclosure) cover replacements	Safety issue with P160 type LV enclosures; we had an injury to a contractor as a result of the fuse failing and burning through the metal LV enclosure cover. We will replace metal covers with plastic covers to mitigate this risk, which is significantly more cost effective than complete replacement.	$0.1m
Building and grounds corrective maintenance uplift	A backlog of corrective maintenance has been identified on both distribution and zone substation buildings and grounds. This needs to be undertaken to ensure whole of life cost management of these assets occurs.	$0.1m
Total		$5.6m

H.4.3. Corrective Maintenance Opex

616. Our corrective maintenance historical and forecast expenditure is shown in Figure 85.

Figure 85: Corrective maintenance historical and forecast Opex



617. Points to note:

- Historically we did not complete sufficient corrective maintenance work. Spend varied per year from the number and type of faults requiring second response work.
- Our proposed additional maintenance (step-changes) results in an uplift of expenditure from RY21 until we complete a number of programmes, we expect to reach a steady-state after RY26.
- The major step change in corrective work is the need to remediate poor condition pre-1984 consumer owned poles and conductor. We have never formally handed over pre 1984 consumer owned lines back to the consumer and, after a recent run of failures, we have prioritised addressing these poles during the CPP period.

Box 30: Corrective maintenance efficiency adjustment

We have applied specific efficiency adjustment factors to corrective maintenance to account for improved contractor productivity following the increased competitive tension created from our new contracting approach. This efficiency has been applied from RY22.

Box 31: Corrective maintenance forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- Base-step-trend: we have used a forecast technique which is industry good practice for this type of expenditure.

- **Clear, prudent drivers:** we identified that the level of corrective maintenance works undertaken historically has not been adequate and have identified key programmes that are required to help address this inadequacy.
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been adjusted based on feedback and discussion including reflecting improving asset condition due to renewals work.

H.5. Reactive Maintenance

619. The reactive maintenance portfolio includes expenditure related to emergency and fault response, and switching in response to an unplanned event or incident that impairs normal network operation.

620. The purpose of this work is to manage any hazardous or operational conditions that arise through network faults, manage the risk to our service providers and the public, and restore supply to customers.

621. The expenditure in this portfolio reflects spend on our service providers. It excludes internal Aurora Energy staff costs associated with managing the work undertaken by our service providers, which is included in our SONS portfolio.

622. Reactive maintenance is related to our corrective maintenance activities. Corrective maintenance includes 'second response' work – i.e. work that follows on from the 'first response', reactive work to address a fault or issue. Under severe conditions, when reactive maintenance requirements are very high, resource availability for other forms of maintenance can be temporarily limited. Weather can have a significant impact on reactive maintenance expenditure.

H.5.1. Investment Drivers

623. A key deliverable of this portfolio is to ensure we meet our proposed services standards and response times. Reactive maintenance work volume is primarily driven by the number of faults on our network. The frequency and duration of these faults will be driven by factors such as:

- **Asset age and condition:** as the ages of our assets increase and condition deteriorates, the volume of faults can be expected to increase
- **Asset types:** assets of different types and from different manufacturers have different characteristics. Some types fail more often than others, and some types are replaced upon failure (e.g. fuses) while others are replaced proactively
- **Number and location of automation devices:** remote devices help reduce event impact, such as by remotely sectionalising the network, thereby speeding up restoration and reducing SAIDI impact
- **Physical location:** rural, remote rural and mountainous areas require additional travel time to address faults.

– **Environmental conditions:** overhead assets, in particular, are more prone to failure in corrosive or high wind locations or in adverse weather. Snow and ice can also increase faults, due to additional structural loading on overhead lines.
– **Third-party incidents:** such as car vs pole and cable strikes caused by third parties lead to outages and potential safety risks.

624. The amount of work we undertake in other maintenance or renewal portfolios affects reactive maintenance volumes, in the longer term. For example, an increase in planned renewal work on the overhead network will tend to decrease reactive maintenance volumes because it improves the condition of assets. Similarly, an increase in corrective maintenance will also gradually reduce the amount of reactive maintenance that is required in the longer term.

H.5.2. Forecasting Approach

625. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

626. The base-step-trend approach involves:

– **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the corrective maintenance portfolio we have used RY19 as the base year.
– **Step changes** required to meet the needs of the network or to allow for external requirements. These can one-off or ongoing changes and involve a change in the scope of work delivered. These are outlined in Table 36.
– **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have applied three trends to the reactive maintenance expenditure
  - **Output growth:** we have relied on the Commission's analysis prepared for the DPP to apply an output growth factor for reactive maintenance
  - **Asset renewal:** We expect to see an increasing rate of improvement from the programme of asset renewal and have estimated a percentage improvement per year.
  - **Efficiency:** We have applied an efficiency trend as outlined in Box 32.

Table 36: Reactive maintenance step change detail

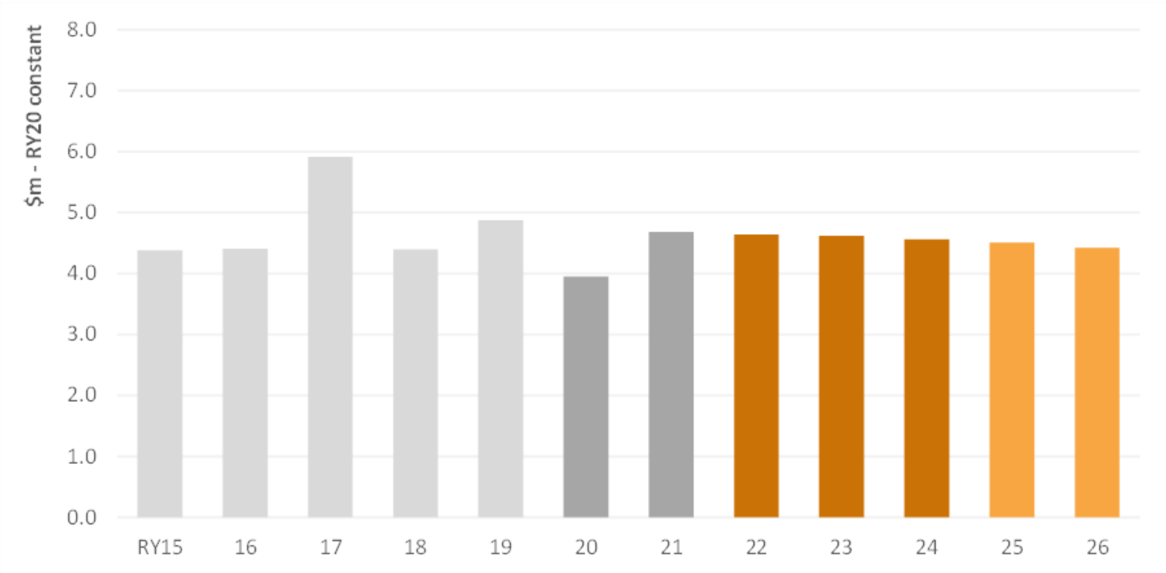
Step Change Description	Need	CPP total
Additional fault response	A key deliverable in this portfolio is to ensure we meet our proposed service standards and response times, we have asked our faults contractor to establish a 24/7 dispatch service to operate and maintain our service and safety needs.	$0.3m

Step Change Description	Need	CPP total
Moderation adjustment	We have moderated the forecast reflecting our expected lower RY20 outturn and taking into account the improved performance of our field crews.	-$0.9m
Total		-$0.6m

H.5.3. Reactive Maintenance Opex

627. Our reactive maintenance historical and forecast expenditure is shown in Figure 86

Figure 86: Reactive maintenance historical and forecast Opex



628. Points to note:

- During RY20, we had fewer third-party incidents and more benign weather than 'normal' and therefore saw a lower level of reactive spend. We consider this year an outlier and expect our future expenditure to be more in line with our historical average.
- Our expenditure has a decreasing trend due to our expectation that the condition of the network will improve over time and therefore reduce the number of faults requiring reactive maintenance expenditure. We also have a downward trend due to expected efficiency improvements as our asset management approach matures.

Box 32: Reactive maintenance efficiency adjustment

We have applied specific efficiency adjustment factors to reactive maintenance to account for improved contractor productivity following the increased competitive tension created from our new contracting approach. This efficiency has been applied from RY22.

Box 33: Reactive maintenance forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Base-step-trend:** We have used a forecast technique which is industry good practice for this type of expenditure. This includes the use of a base year that reflects historical spend and includes activities we expect to recur.
- **Improvement in other portfolios:** We have accounted for expected improvement in asset condition due to the uplift in renewals. This has enabled us to apply a reduction to forecast expenditure over time.
- **Review and moderation:** Our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been moderated based on feedback and discussion.

H.6. Vegetation Management

630. Vegetation management involves monitoring vegetation growing in close proximity to our assets, liaising with landowners, and trimming and removing vegetation to keep it clear of overhead lines. Vegetation management Opex comprises of the costs attributed to our vegetation contractor to undertake this work.

631. Vegetation can have a notable impact upon network safety and reliability. Trees in close proximity to live conductors pose a risk of electrocution and fire to our people and our local communities. Further, such events can result in significant damage to network equipment prompting network outages. On a national level, vegetation is one of the main contributors to unplanned SAIDI and SAIFI performance.

632. Effective vegetation management ensures that Aurora Energy adheres to existing regulations, namely the Electricity (Hazards from Trees) Regulations 2003 which establish the rights and responsibilities for network owners regarding vegetation that encroaches overhead lines.

633. Our current approach is largely reactive, responding to issues as they are identified by line inspections, notification, or after faults. We are moving to a more proactive, cyclical approach which will give us better visibility of the status of vegetation around lines, enabling us to take appropriate actions to minimise risk.

H.6.1. Investment Drivers

634. The key expenditure drivers for our proposed expenditure on vegetation management include:

- **Legislative or Regulatory requirements:** compliance with the Tree Regulations
- **Safety:** provide a safe network for the public, our staff and contractors
- **Prevention of equipment damage:** reduce the risk of vegetation related events damaging network equipment

- **Reliability:** provide a reliable network for our customers, while meeting the agreed service levels

H.6.2. Forecasting Approach

635. Our expenditure forecasts for the CPP period are based on a volumetric approach. We estimate the length of exposed vegetation across our network feeders and then apply a unit rate (cost per kilometre of exposed vegetation). Both have been developed based on performance data related to historical management of vegetation on our network.

636. These quantities and costs are explained below.

Quantities – Estimated Length of Exposed Vegetation

637. This estimate is based upon the overall route length of each feeder within our network, and the expected vegetation density along each feeder. The overall feeder route length measures from a zone substation to every feeder end point, whether that is a 11kV, 6.6kV, 400V or a combination of voltages.

638. Subtransmission circuits are treated separately with all circuits currently in a managed state, compliant with the regulations and a subject to a 6-monthly inspection.

639. The vegetation density estimates have been created using feeders which have already undergone initial (first cut) vegetation management and applied to catch-up feeders, those which are yet to undergo initial first cut management. Vegetation density estimates for feeders have been based on region (Dunedin, Central Otago) and class (Urban, Rural, Semi-Rural) defined as follows:

- **Urban:** areas where at least 80% of overhead route length is in urban areas.
- **Semi-rural:** areas that fell between the threshold for the rural and urban classes.
- **Rural:** areas where at least 80% of overhead route length was in rural areas.

640. In order to calculate the overall length of exposed vegetation per feeder, each feeder length is multiplied by the relevant density percentage based upon region and class. From this data, a vegetation management plan has been developed for Dunedin and Central Otago with set feeders scheduled for completion each quarter of each regulatory year.

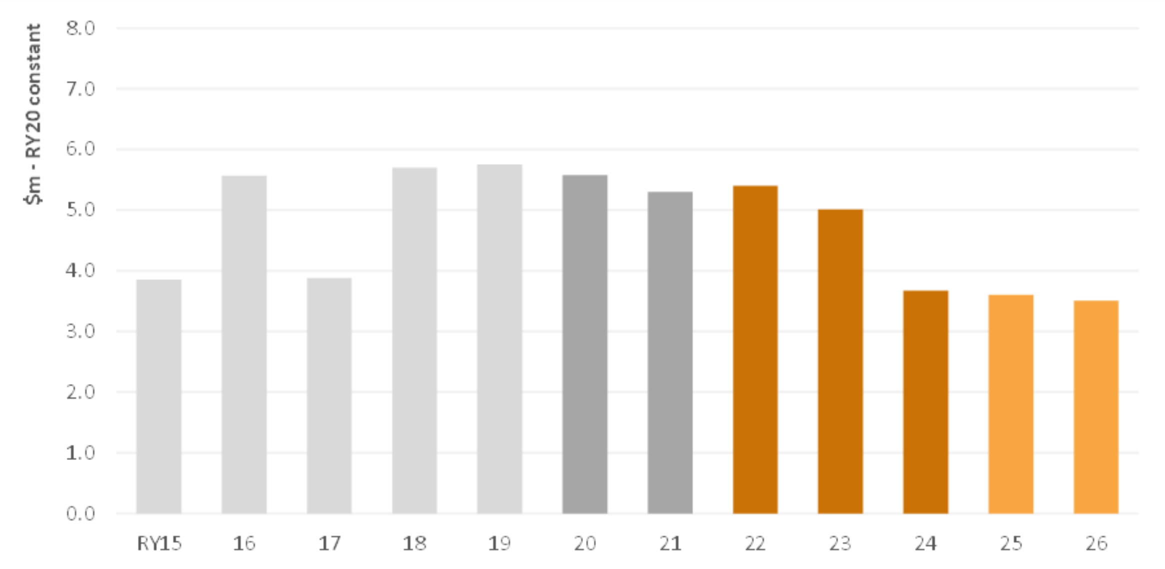
Costs – Unit Rate

641. The estimate for the vegetation management unit rate is based on cost performance data from previous years. The figure includes all costs incurred through first cut vegetation activities including liaison, administration, traffic management, etc. We have applied this unit rate to the estimated length of exposed vegetation per year to produce a forecast for vegetation management.

H.6.3. Vegetation Management Opex

642. Our vegetation management historical and forecast expenditure is shown in Figure 87.

Figure 87: Vegetation management historical and forecast Opex



643. Points to note:

- Our planned expenditure through until RY23 is in line with our historical expenditure to cover our 'first cut' cycle of vegetation management.
- We will return to a steady state 5-year management cycle in RY24

Box 34: Vegetation management efficiency adjustment

We have applied specific efficiency adjustment factors to vegetation management. We expect to see improvement in contractor productivity following the introduction of a competitive environment. We also expect an improvement in works coordination following the implementation of better asset management tools. These efficiencies have been applied from RY21.

Box 35: Vegetation management forecast justification

We are confident that our approach delivers an efficient and prudent level of expenditure because:

- **Reliability and safety:** over time our new approach will help improve network safety and stabilise network performance and reliability.
- **Good practice:** our proposed vegetation management approach reflects good New Zealand practice.
- **Compliance:** the proposed approach will ensure full compliance with the Tree Regulations.
- **Lower costs:** over time the greater cutting clearance and/or tree hazard removal will result in lower vegetation management costs to Aurora and customers
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been adjusted during this process.

Appendix I. NON-NETWORK EXPENDITURE

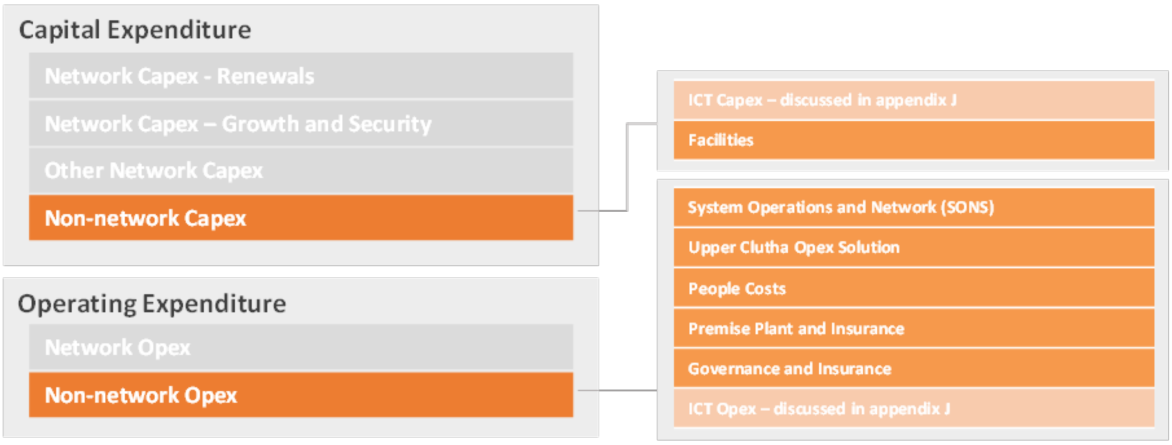
I.1. INTRODUCTION

645. Non-network expenditure (Non-network Capex and Opex) is the expenditure we incur to operate our business.

646. Non-network expenditure incorporates our staff, asset management, customer engagement and business operations functions. Appropriate non-network expenditure allows us to efficiently manage our network and meet our business and regulatory needs.

647. Figure 88 illustrates where non-network expenditure sits within our overall expenditure and the portfolios that make up the category.

Figure 88: Non-network Capex and Opex portfolios



648. As depicted above, the non-network Opex category includes the following expenditure portfolios:

- **System operations and network support (SONS):** comprises the management and operation of our network and associated assets
- **Upper Clutha DER solution:** this is a solution to the Upper Clutha growth constraints involving payments for use of third party owned small scale distributed generation and battery systems
- **People costs:** the cost of employing business support staff and external service providers.
- **Premise plant and insurance:** incorporates the running costs of our offices and the running and leasing costs of plant and motor vehicles.
- **Governance and administration:** comprises governance and general administration costs associated with operating and supporting our business.
- **ICT Opex:** appendix J outlines our ICT expenditure

649. The non-network Capex category includes the following expenditure portfolios:

- **ICT Capex:** appendix J outlines our ICT expenditure
- **Facilities:** primarily involves our investments in office equipment and fit outs.

1.2. Expenditure Overview

650. Figure 89 sets out our non-network Opex for the CPP period together with the historical expenditure. The non-network Capex expenditure is set out in Figure 90.

Figure 89: Non-network Opex historical and forecast expenditure

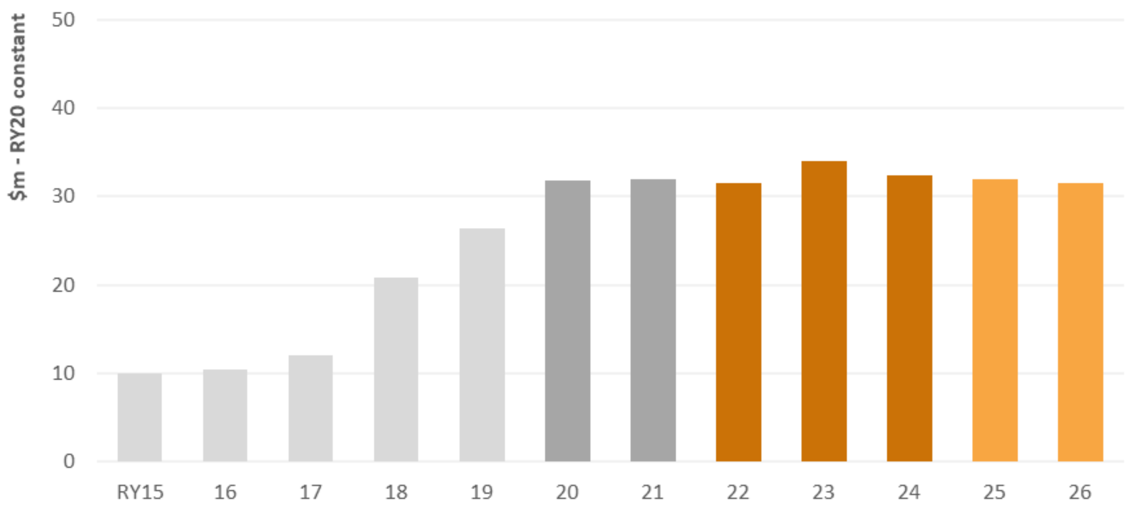
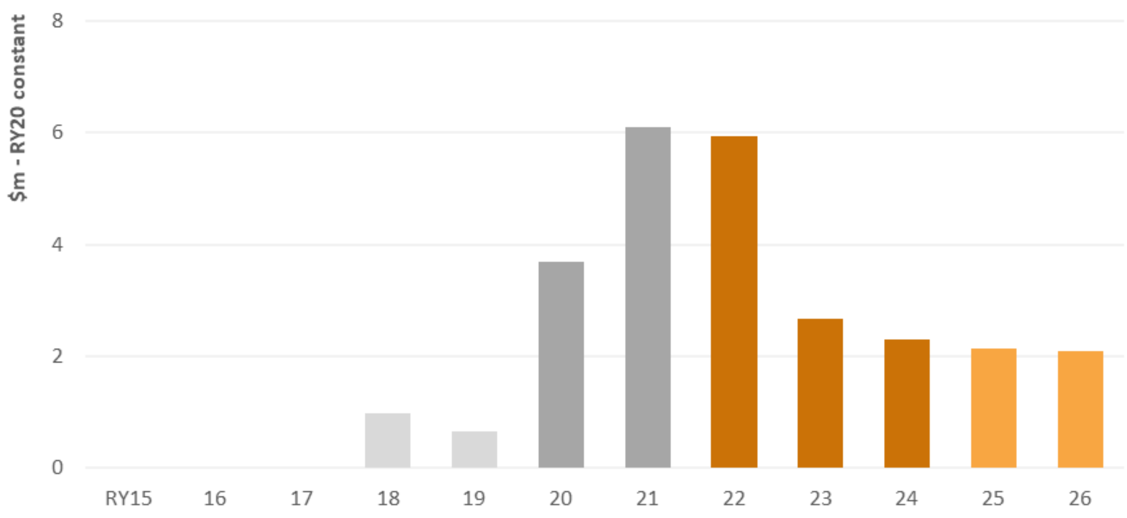


Figure 90: Non-network Capex historical and forecast expenditure



651. During the CPP period we expect to invest $97.9m in non-network Opex portfolios and $10.9m in non-network Capex portfolios. Points to note:

- Historically we paid an annual management fee to Delta for the provision of asset management, network operations and maintenance services.
- We restructured our business in 2017 to operate as a standalone asset owner and manager. This included restructuring of our corporate functions.

- We expect to have fully recruited for the establishment of our efficient long-term staff needs prior to the commencement of the CPP period.
- Details of the ICT Opex and Capex spend is outlined in appendix J.

I.3. Inputs and Assumptions

652. In developing our non-network expenditure forecasts, we have made the following key assumptions:

- Our asset management capability plays an essential role in delivering a safer network, improving asset health and stabilising reliability performance.
- Our priority prior to the commencement of the CPP forecast period is to recruit staff to an efficient and prudent level that allows us to meet our asset management and business support needs.
- Continued recruitment to an efficient and prudent level of business support staff will allow us to meet our customer engagement, business and regulatory and business improvement requirements.
- An Opex solution is the optimal response to the Upper Clutha growth security constraints.
- A balanced approach between affordability and being prepared is an appropriate response to future network evolution challenges.

I.4. SONS

653. The SONS portfolio covers the costs relating to managing and operating our electricity network. It excludes expenditure on capital projects, network equipment, field services and corporate costs.

654. SONS comprises asset management and planning; operations and network performance; works programming and service delivery; regulatory and commercial (noting that most of these costs are allocated to Business Support); operational technology; customer initiated works and contact centre; and planning and delivery process design functions.

655. Our expenditure forecasts reflect the cost of continuing to implement our new organisational structure and ensuring that we have the right resources and capabilities to deliver our planned work programme efficiently. By the end of RY20, we expect staffing to align with our longer-term target levels so that gaps in key roles are filled.

I.4.1. Investment Drivers

656. The key expenditure drivers for this portfolio are:

- **Asset management capability:** improving our asset management capability, which currently falls short of best practice;
- **Network investment support:** Delivering our increased work programme, which requires additional support in terms of planning, works programming, customer engagement and delivery.

657. Our asset management capability plays an essential role in delivering a safer network, improving asset health and stabilising reliability performance. We have embarked upon an ambitious plan to seek ISO 55000 certification by 2023. Supported by asset management experts, AMCL, the existing gaps in our processes and systems have been identified and a roadmap to address them has been developed.

658. During the CPP period we will be focusing on improving our asset management documentation to provide a clear line of sight from our objectives through to the roles and responsibilities of our staff. We will also focus on making better use of the information that is currently available; improving the quality of the data collected; and ensuring that it is readily accessible across the business. These changes will enable us to deliver better customer outcomes over time.

Network evolution

659. We will initiate the implementation of our Network Evolution Plan to enable us to respond prudently and efficiently to the projected increases in distributed energy resources on our network.

660. The changes we expect to see are part of a global trend, as developed economies continue to decarbonise. Given New Zealand's CO_2 emissions profile, substantial greenhouse gas emissions reductions can be achieved by replacing road vehicle transport with EVs. As this replacement occurs, more renewable energy must be developed, and PV is likely to be part of this picture.

661. We consider that these additional activities in the CPP period appropriately balance the need to prepare the network for the challenges ahead, whilst having regard to affordability. Our network evolution plan includes a fourth theme proposing greater research and experimentation and use of network technology to assist with asset condition assessment. As a consequence of consultation feedback we have removed theme 4 from our proposal and will revisit this at a later date.

I.4.2. Forecasting Approach

662. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

663. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the SONS portfolio we have used RY19 as the base year.
- **Step changes** required to meet the needs of our network operation and management. These can be one-off or ongoing changes and involve a change in the scope of work delivered. The three key step changes to the SONS portfolio forecast
  - **Increased staffing requirements:** We will increase our staffing levels and expect to have our long-term efficient SONS staffing levels recruited prior to the start of the CPP period
  - **Network evolution investment:** We will commence our network evolution initiatives during the CPP period. The investment will enable us to respond prudently and efficiently to the projected increases in distributed energy resources on our network

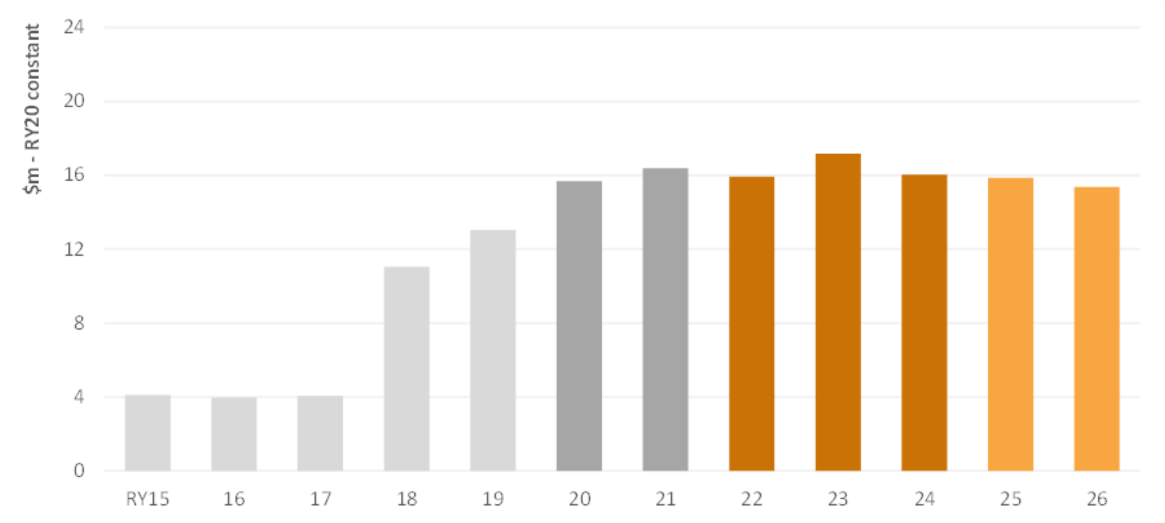
- **CPP application costs:** We have forecast to incur $1.4m of expenditure over RY23 and RY24 for the preparation of a second CPP proposal.

– **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have applied an efficiency trend to the SONS expenditure as outlined in Box 36.

I.4.3. SONS Expenditure

664. Our SONS portfolio historical and forecast expenditure is shown in Figure 91.

Figure 91: SONS historical and forecast Opex



665. Points to note:

– Historically we paid an annual management fee to Delta for the provision of asset management and network operations services.

– We expect to have fully recruited for the establishment of our efficient long-term SONS staffing needs prior to the commencement of the CPP.

– We will initiate our Network Evolution Plan that will enable us to respond prudently and efficiently to the projected increases in distributed energy resources on our network.

– We have forecast expenditure during RY23 and RY24 for the preparation of a second CPP proposal.

Box 36: SONS efficiency adjustment

We have applied specific efficiency adjustment factors to SONS expenditure to account for our improving capability. We expect to see efficiency as we mature our systems and processes and realise benefits from our IT investments (e.g. EAMS).

Box 37: SONS forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- Base-step-trend: we have used a forecast technique which is industry good practice for this type of expenditure.
- Clear, prudent drivers: we identified the level of staffing and identified key programmes that are required to help address our asset management needs.
- Review and moderation: our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been adjusted based on feedback and discussion including proposed staff positions and the timing of our network evolution investments.
- Comparable: Our forecast efficient non-network Opex expenditure compares favourably to other EDBs.

I.5. Upper Clutha DER Opex Solution

667. The Upper Clutha Opex solution is an Opex solution to the growth security constraints we have forecast on the Upper Clutha network. This has gone through the Growth and Security options analysis process and we have found that a non-network Opex solution is the preferred option to address these constraints. The expenditure is outlined in the following sections.

I.5.1. Project Need

668. The Upper Clutha region (Wanaka, Hawea, Cardrona and the surrounding farming district) is supplied by two 66 kV circuits. Each circuit is supplied from Transpower's Cromwell substation via 33/66 kV auto-transformers. The transformers connect directly to each 66 kV circuit at Cromwell as there is no 66 kV bus.

669. A number of constraints are projected on the Cromwell-Riverbank 66 kV circuits over the next decade, in the event that one of the 66 kV circuits is out of service during peak load conditions (from first to last):

- An existing voltage constraint - addressed by the Upper Clutha voltage support project. We plan to install 10 MVAr of capacitor banks within the Upper Clutha network to relieve the constraint during circuit outages.
- The capacity of a single, 30/37 MVA, auto-transformer that supplies an Upper Clutha circuit will be exceeded in 2025.
- A second voltage constraint requiring additional reactive support will occur, shortly followed by overloading of a single Cromwell-Riverbank 66 kV line/cable circuit in 2029.

I.5.2. Shortlisted Options

670. To address the constraints over the AMP period on the Upper Clutha lines the following options were shortlisted:

- **New Upper Clutha 66kV line:** This option involves constructing a new ≈19 km, 66 kV overhead line between the Roaring Meg power station and our Cardrona zone substation and rebuilding the existing 33kV line between the Cromwell GXP and Roaring Meg to operate at 66 kV. It will also require a new 30 MVA, 66/33 kV auto-transformer at Cromwell and associated switchgear.
- **New Cromwell to Camp Hill 66kV line:** This option involves constructing a new ~60 km, 66 kV line between the Cromwell GXP and our Camp Hill Substation. Also, rebuilding the existing kV line between our Camp Hill and Wanaka zone substations as a 66kV line. A new 66/33 kV auto-transformer would need to be installed at the Cromwell GXP and associated switchgear.
- **Reconductor existing 66kV lines and upgrade auto-transformers:** This option involves relieving the network capacity constraints as they occur. In RY25 the existing Cromwell 33/66kV, 30 MVA auto-transformers would be replaced with 60 MVA units. The existing two ~54 km, 66 kV Upper Clutha lines would be upgraded to Wolf conductor in RY29.
- **Non-network capacity support using third-party large scale generation:** This option was identified from a 'Request For Proposal' for non-network capacity support in the Upper Clutha Area. It involves third-party owned large-scale distributed generation to supply the Upper Clutha area and requires some network upgrades to connect the distributed generation.
- **Non-network capacity support using third-party small-scale distributed generation and battery systems:** This option was identified from a 'Request For Proposal' for non-network capacity support in the Upper Clutha Area. It involves providing demand reduction in response to a time-of-use tariff in consumers' homes or small-businesses in the Upper Clutha area. It also involves demand management for maintenance work and a post contingency demand reduction in response to a control signal from our control centre.

I.5.3. Project Solution

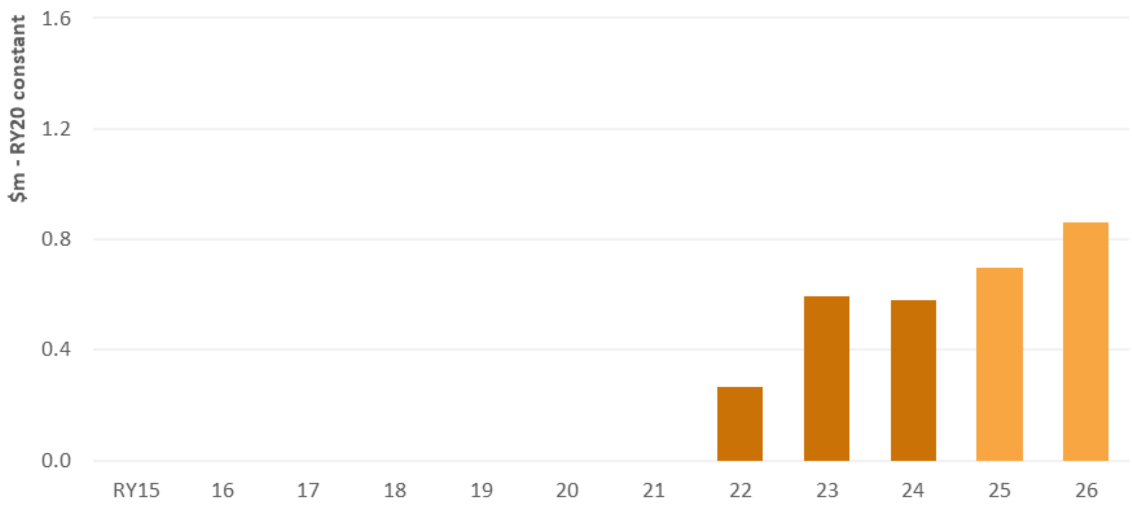
671. The preferred option is to proceed with the non-network capacity support using third-party small-scale distributed generation and battery systems, which involves: (1) partnering with a supplier of both small-scale distributed generation and battery energy storage; and (2) opening up the possibility for other aggregators to come forward with similar solutions if and when we need them.

672. Both non-network capacity support options involve contracting with third party and provision of capacity support from distributed generators in the Upper Clutha area. In both cases the installation and operation of the equipment for these will lead to increased economic activity in the Upper Clutha area. Furthermore, in the case of the small scale distribution the non-network support is effectively purchased from consumers in the area, via the third-party installer. Thus, it returns value to consumers in the Upper Clutha area through lower electricity bills.

673. Both non-network capacity support options involve renewable generation, which is desirable in terms of contributing to reducing New Zealand's greenhouse gas emissions. It is even possible that they may be bundled with electric vehicle options and thereby contribute even more to reducing greenhouse gas emissions.

674. The forecast expenditure for this solution is shown in Figure 92.

Figure 92: Upper Clutha DER Opex solution forecast expenditure



Box 38: Upper Clutha DER Opex solution forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Appropriate needs and options analysis process:** Our process for identifying needs and options analysis follows good industry practice in that it uses a long list and short list approach supported by detailed analysis.
- **Economic analysis:** Our process determines the least cost technically acceptable solution through applying a formal NPV based test. Our approach to investment planning focusses on assessing the costs and benefits of addressing the breach of our security of supply guidelines and ensuring that the investment delivers benefits to the customer.
- **Prudent security of supply guidelines:** We have compared our guidelines to those applied by others and have confirmed that they are appropriate for our network.
- **Prudent use of our security of supply guidelines:** Our guidelines are used as a trigger to initiate further detailed analysis; they are not absolute. In addition, we consider intangible benefits and input from our engineering team and service providers when identifying network needs.
- **Industry good practice load forecast model:** We have built, with the assistance of Ernst & Young (EY), an industry good practice load forecast model to produce a demand forecast and assist us in identifying constraints on the network.

I.6. People Costs

676. The people costs portfolio covers the cost of employing business support staff and external service providers. It 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 administration costs that are not employment related.

677. People costs comprises staff costs for human resources and communications; accounting and finance and risk assurance; regulatory and commercial; and information technology (IT) functions.

678. Our expenditure forecasts reflect the cost of continuing to implement our new organisational structure and ensuring that we have the right resources and capabilities to deliver our business functions efficiently. By the end of RY20, we expect staffing to align with our longer-term target levels so that gaps in key roles are filled.

I.6.1. Investment Drivers

679. The key expenditure drivers for this portfolio are:

- **Business and regulatory requirements:** prudent and efficient investment in staff and staff support costs are required for us to meet our business and regulatory requirements.
- **Customer engagement:** our consultation identified customer engagement as a key aspect of our service delivery. Investment in our capability and capacity will add value to our customer experiences appropriately manage customer disruption from our network investments.
- **Business initiatives and change management:** investment in business improvement is required for us to effectively and efficiently complete the transition to a stand-alone entity as well as to increase our capacity to meet our increasing network investment activity

680. Staff levels have increased as a result of the changes to our organisational structure. Increased work volumes have driven the need for additional staff in areas such as customer engagement, human resources and risk assurance. Recent actuals and forecast costs reflect the continuing change initiatives across our business support functions as we look to continue to build the right levels of internal capability and capacity.

I.6.2. Forecasting Approach

681. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

682. The base-step-trend approach involves:

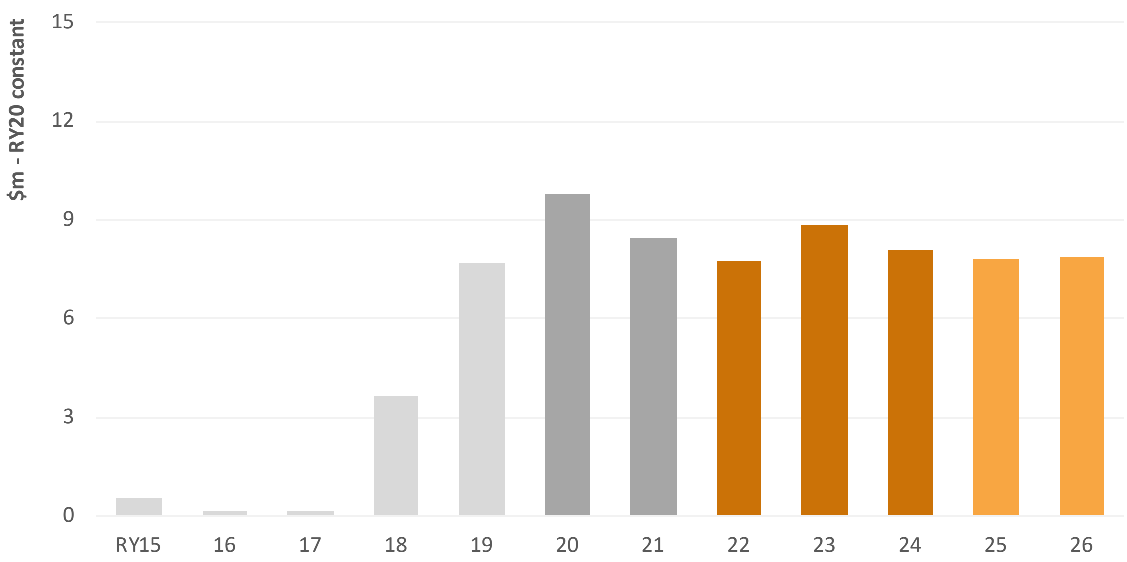
- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the People costs portfolio we have used RY19 as the base year.

- **Step changes** required to meet the staff needs of the business. These can be one-off or ongoing changes and involve a change in the scope of work delivered. The key step changes to the People costs portfolio forecast
  - **Increased staffing requirements:** We will increase our staffing levels and expect to have our long-term efficient staffing levels recruited prior to the start of the CPP period
  - **CPP application costs:** We have forecast to incur $1.4m of additional people costs over RY23 and RY24 for the preparation of a second CPP proposal.
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have applied an efficiency trend to the People costs expenditure as outlined in Box 39.

I.6.3. People Costs Expenditure

683. Our people costs portfolio historical and forecast expenditure is shown in Figure 93.

Figure 93: People costs historical and forecast Opex



684. Points to note:

- Historically we paid an annual management fee to Delta for the provision of corporate services.
- We expect to have fully recruited for the establishment of our efficient long-term staffing needs prior to the commencement of the CPP period.
- We have forecast expenditure during RY23 and RY24 for the preparation of a second CPP proposal.

Box 39: People costs efficiency adjustment

We have applied specific efficiency adjustment factors to People costs expenditure to account for our improving capability. We expect to see efficiency as we mature our systems and processes and realise benefits from our IT investments.

Box 40: People costs forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Base-step-trend:** we have used a forecast technique which is industry good practice for this type of expenditure.
- **Clear, prudent drivers:** we identified the level of staffing and identified key programmes that are required to help address our business needs.
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board, and the forecasts have been adjusted based on feedback and discussion including proposed staff positions.
- **Comparable:** Our forecast efficient non-network Opex expenditure compares favourably to other EDBs.

I.7. Premise Plant and Insurance

686. Premise, plant and insurance includes the running costs of our offices and the running and leasing costs of plant and motor vehicles utilised within our corporate function. It also covers the insurance costs associated with insuring some of our electricity network assets, general liability and indemnity cover, and other smaller insurance policies.

I.7.1. Investment Drivers

687. The key expenditure drivers for this portfolio are:

- **Staff numbers:** as our staff levels increase to meet our capability and capacity requirements so do our premise and plant costs including increased accommodation costs
- **Insurance premiums:** insurance premiums are a significant driver of our insurance costs.

688. Our accommodation needs are changing as we increase our number of staff. Our expenditure forecast includes allowances for increased accommodation based on forecast staff levels.

689. Insurance premiums are expected to increase over the forecast period. We worked with our insurance service provider to predict expected increases in annual premiums.

I.7.2. Forecasting Approach

690. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

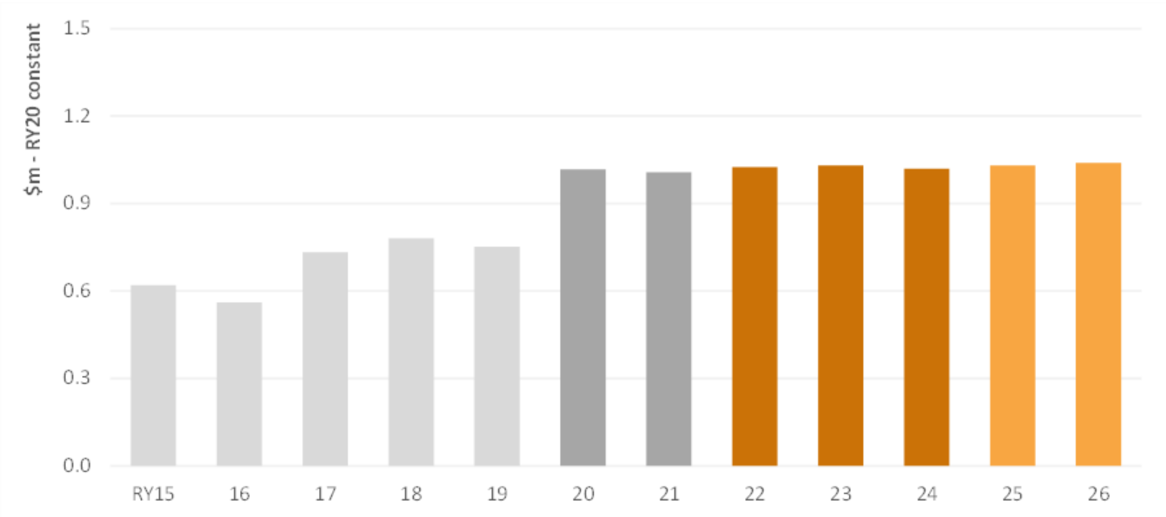
691. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the Premise plant and insurance portfolio we have used RY19 as the base year.
- **Step changes** required to meet the needs of the business. These can be one-off or ongoing changes and involve a change in service or capacity. The key step changes to the Premise plant and equipment portfolio forecast
    - **Accommodation costs:** We have forecast an increase in lease costs to accommodate our increased staffing levels
    - **Insurance costs:** We forecast increases in our insurance premiums that reflects expected changing insurance premiums across the insurance sector
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have not applied any trend adjustments to the premise plant and insurance costs portfolio.

I.7.3. Premise Plant and Insurance Expenditure

692. Our Premise plant and insurance portfolio historical and forecast expenditure is shown in Figure 94.

Figure 94: Premise plant and insurance costs historical and forecast Opex



693. Points to note:

- Historically we paid an annual management fee to Delta for the provision of premise and plant services.
- Our forecast includes an increase in lease costs to accommodate our increased staff levels.
- Insurance premiums are expected to increase.

Box 41: Premise plant and insurance forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Base-step-trend:** we have used a forecast technique which is industry good practice for this type of expenditure.
- **Clear, prudent drivers:** we identified key expenditure needs to accommodate our staff levels and tested our insurance needs with our insurance service provider.
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board, and the forecasts
- **Comparable:** Our forecast efficient non-network Opex expenditure compares favourably to other EDBs.

I.8. Governance and Administration

695. The governance and administration portfolio comprises governance and general administration costs associated with operating and supporting our business. It includes costs relating to our board of directors, audit and assurance programmes, legal fees and consumables.

I.8.1. Investment Drivers

696. The key expenditure drivers for this portfolio are:

- **Governance and assurance requirements:** investment in governance and assurance services ensures our business are meeting our customer, staff and legal requirements

697. Our review of our governance and administration needs for the business identified changing needs requiring redeployment of resources across the portfolio. Our forecast governance and administration expenditure is broadly consistent with our actual RY19 costs.

I.8.2. Forecasting Approach

698. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

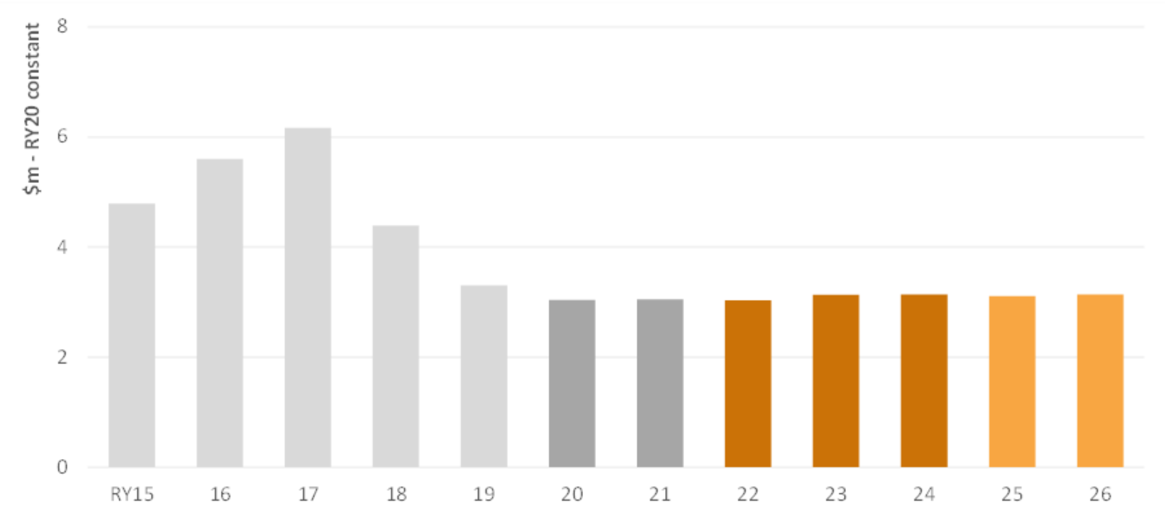
699. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the Governance and administration portfolio we have used RY19 as the base year.
- **Step changes** required to meet the needs of the business. These can be one-off or ongoing changes and involve a change in service or capacity. We have not forecast any material step changes for Governance and administration.
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have not applied any trend adjustments to the Governance and administration costs portfolio.

I.8.3. Governance and Administration Expenditure

700. Our Governance and administration portfolio historical and forecast expenditure is shown in Figure 95.

Figure 95 : Governance and administration costs historical and forecast Opex



701. Points to note:

- Historically we paid an annual management fee to Delta for the provision of corporate services.
- Our forecast governance and administration expenditure is broadly consistent with our actual RY19 costs.

Box 42: Governance and administration forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Base-step-trend:** we have used a forecast technique which is industry good practice for this type of expenditure.
- **Clear, prudent drivers:** we identified key expenditure needs to meet our governance and administration needs.
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board.
- **Comparable:** Our forecast efficient and prudent non-network Opex expenditure compares favourably to other EDBs.

I.9. FACILITIES

703. The Facilities non-network Capex portfolio comprises our investment in non-network assets other than ICT investments. Office equipment and fit outs expenditure is included in this portfolio.

I.9.1. Investment Drivers

704. The key expenditure drivers for this portfolio are:

- **Staff numbers:** Our staff levels dictate our accommodation and equipment investments requirements.

705. In reviewing our accommodation and equipment levels based on increased staff numbers we identified a need for further investment. For our staff to be accommodated and to work in an efficient and prudent manner we will invest in our fit out before the CPP period begins.

706. During the forecast period we expect equipment investments will be consistent with historical levels and we continue to replace and upgrade equipment on a steady state basis.

I.9.2. Forecasting Approach

707. We have adopted a 'base-step-trend approach' to forecasting. This approach is used by many utilities and economic regulators for forecasting recurring expenditure.

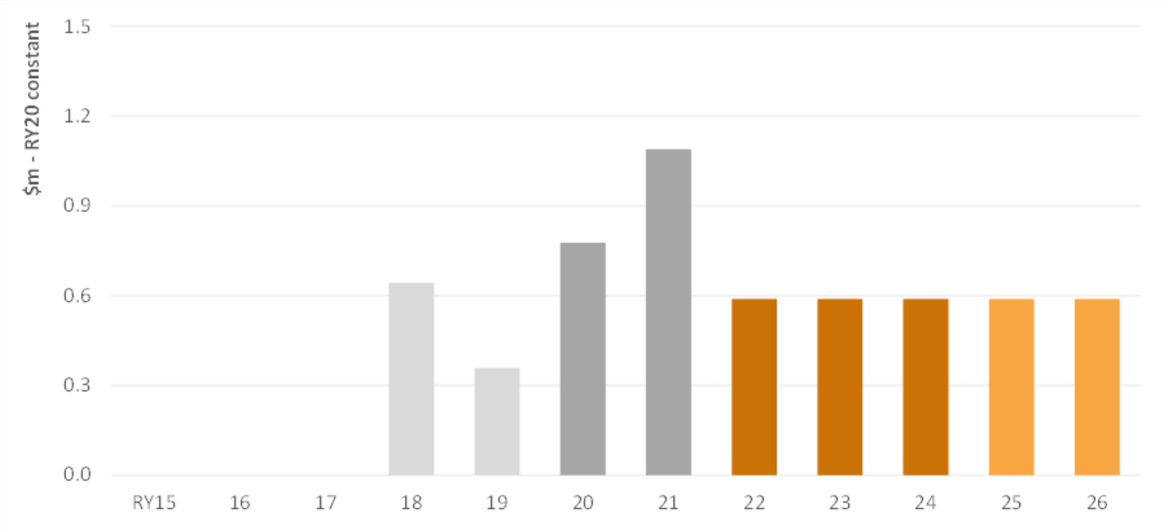
708. The base-step-trend approach involves:

- **Base amount:** identifying an efficient base year, making adjustments as necessary. This base cost is then projected forward. For the Facilities portfolio we have used an average of prior years and budgeted costs as the base year.
- **Step changes** required to meet the needs of the business. These can be one-off or ongoing changes and involve a change in service or capacity. We have included a single on-off step change prior to the forecast CPP period for office refurbishment.
- **Trend changes** that reflect expected changes in cost due to output growth and expected cost efficiencies. We have not applied any trend adjustments to the Facilities portfolio.

I.9.3. Facilities Expenditure

709. Our Facilities portfolio historical and forecast expenditure is shown in Figure 96.

Figure 96: Facilities costs historical and forecast Capex



710. Points to note:

- Our CPP forecast Facilities expenditure is broadly consistent with our historical costs.
- We have included a single one-off investment prior to the CPP forecast period for office fit out.

Box 43: Facilities forecast justification

We are confident that our approach delivers an efficient and prudent level of investment because:

- **Base-step-trend:** we have used a forecast technique which is industry good practice for this type of expenditure.
- **Clear, prudent drivers:** we identified key expenditure drivers for our facilities capital investment needs.
- **Review and moderation:** our forecasts have been tested and reviewed by executive management and the Board.

Appendix J. ICT Expenditure

J.1. Introduction

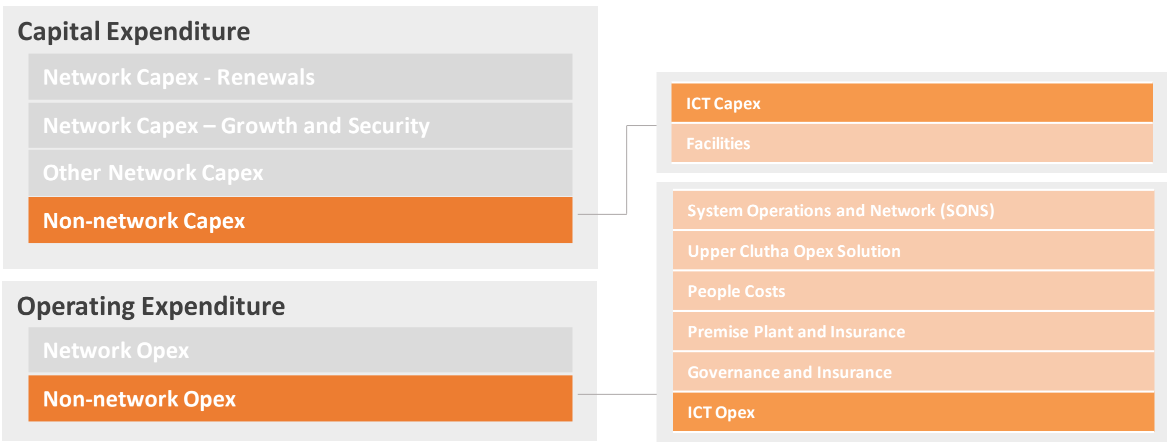
712. This appendix outlines both capital and operating expenditures for Information and Communications Technology (ICT Capex and Opex), describing our forecasting approach and setting out the drivers for investment. ICT Capex and Opex cover the costs of supporting and enhancing the infrastructure, information services and applications that support our electricity business. It excludes operating expenditure on staff and real-time systems.

713. A key theme for Aurora's ICT initiatives from RY20 to the end of the CPP period is the modernisation, standardisation and simplification of the environment, using third-party hosted cloud services where possible. The impact of this shift to cloud-based solutions at Aurora is that the balance of our ICT expenditures changes from 55% Capex in RY20 to 31% in RY26 making analysis of either cost category in isolation meaningless.

714. Regulatory disclosure rules categorise ICT costs as part of "Non-network Capex" and "Non-network Opex". Given the one-off transition from Capex to Opex over the period, we have separated ICT into this single appendix covering both ICT Capex and Opex.

715. Figure 97 illustrates where ICT Capex and Opex sits within our overall expenditure and the portfolios that make up the category

Figure 97: ICT portfolios



716. As depicted above, ICT includes the following services:

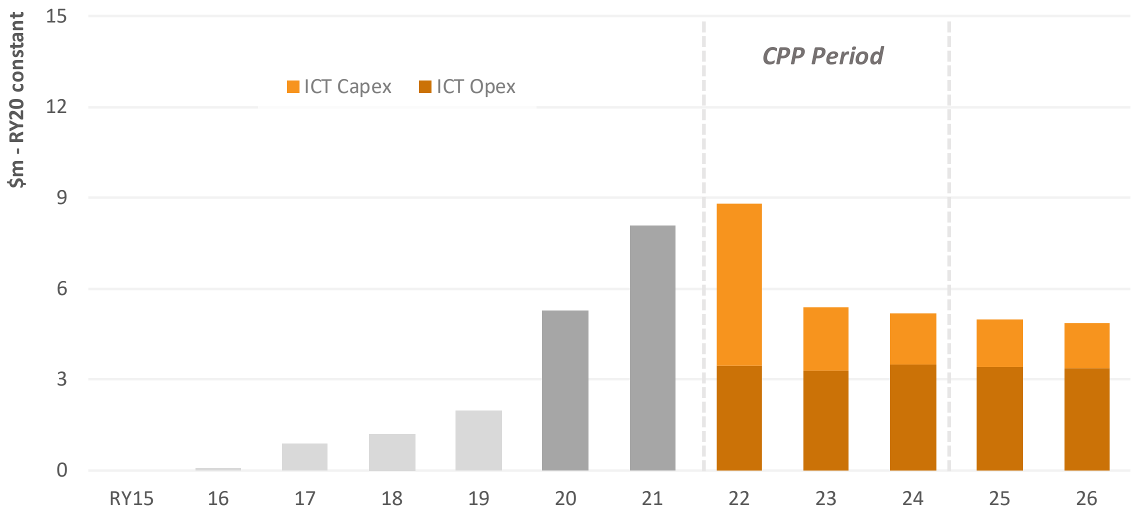
- Asset Management: the dedicated ICT tools that support Aurora's work and asset maintenance and management and new initiatives to establish a competency framework and capability programme to deliver Aurora's AMP and ultimately achieve ISO55000 certification by 2023.
- Corporate: ICT support for back-office functions at Aurora - Finance, HR, Health & Safety and Property as well as generic digital workflow capabilities that can be used across the business.

- Customer and Commercial: Contact and case management solutions – managing customer information and the workflows around customer-initiated works.
- Enterprise Technology and Infrastructure: enabling computing, storage and cyber security capabilities which our business- facing ICT services draw on and
- Operational Technology: maintaining Aurora's Advanced Distribution Management System, related IT and communications infrastructure including fibre, microwave and radio telephone.

J.2. EXPENDITURE

717. Figure 98 sets out our ICT Capex and Opex for the CPP period together with the actual expenditure for RY20. For 20 years, prior to July 2017, Aurora's ICT services were subcontracted to Delta as a management charge, minimising costs in the short-term, but which has left Aurora with a backlog of lifecycle expenditure. As a result, like-for-like ICT expenditure for Aurora is not available before RY20 when the actual costs of Aurora ICT are reported separately from Delta.

Figure 98: ICT Capex and Opex historical and forecast expenditure



718. During the CPP period, total forecast expenditure for ICT is $19.4m or $6.5m per year on average - $3.1m Capex and $3.4m Opex. Points to note:

- Total ICT expenditures will return to RY20 levels in RY24 once we have updated our existing assets to a state where the risk of their failure can be managed commercially and deployed the new tools and technologies required to support our asset management strategy.
- The majority of changes will be committed in RY21 where total ICT expenditure will rise to $8.1m.

719. ICT services for EDBs have traditionally been provided in-house – with all infrastructure and software owned and operated by the regulated business. Shared services have offered economies of scope and scale and in some cases 3rd parties have offered subscription-based "cloud" services where

companies have been able to deploy standard business applications such as email and productivity tools over the internet without the need to own any of the enabling hardware or software. Migrating existing services to the cloud eliminates the need for new capitalised assets and the maintenance of them but adds new Opex for licence fees.

720. These cloud hosted technologies are more prevalent across all sectors of the economy, including the energy industry. Cloud hosting brings many benefits for technology systems, including greater scalability and flexibility, agility, and lower infrastructure costs. It can also drive greater staff productivity and reduce risks of owning infrastructure, through outsourcing, albeit with new costs and risks.

721. A managed migration of our ICT environment to the cloud will ensure that we

- stay on current releases of software and hardware and so retain vendor support and
- apply critical bugs and patches ensuring operations continue to run smoothly all with limited disruption to ensure continuity and reliability of supply.

722. We will time and sequence our migration to the cloud to balance the risks and costs of doing so against the benefits that it offers.

723. In the CPP period RY2022-2024 period, Aurora will move its services and data to the cloud where it makes sense – for example:

- Where costs are lowest;
- Where additional capability is needed (typically as a result of end of life of existing systems, or if there are additional regulatory requirements);
- Where vendors are only providing cloud solutions; or
- Where the cloud solution is a key enabler for other technologies such as analytics or automation.

J.3. Inputs and Assumptions

724. In developing ICT Capex and Opex forecasts, we have made the following assumptions:

- The priority for ICT in the CPP period is to deliver the information and process automation required for Aurora to implement its asset management strategy. This strategy will see the company achieve ISO 55000 certification by 2023.
- We anticipate the impact of distributed energy resources on our network can be managed by exception during the CPP period but will require enterprise ICT tools to be established in RY25 and beyond.
- No project contingencies have been included in expenditure estimates.

J.4. ICT Portfolios

725. The Information & Communications Technology (ICT) portfolio covers both the capital and operating costs of supporting and enhancing the infrastructure, information services and applications that support our electricity business. It excludes operating expenditure on staff and real-time systems.

726. Our current priorities are improving the way we manage and use information across the company and establishing an Enterprise Asset Management system capability. Work is underway on this and will largely be complete before the CPP period. Given the pressures on Aurora's internal resources and the urgency with which we must improve our capabilities we are not currently contemplating a major ERP-based transformation but a fit for purpose transition based on core enterprise systems, improved digital integration and consistent information sourcing and management.

J.4.1. Investment Drivers

727. Our goal in developing the ICT Programme for the CPP period, is to meet the Commission's expenditure objective. Developing the programme is complicated by three factors:

- Aurora Energy's ICT environment was previously provided by Delta and has been allowed to age and deviate from industry standard configurations to the point where the risk of service failures is not fully managed;
- Aurora Energy needs to develop the ICT capability to support the asset and enterprise data management strategies that it will need to follow if it is to deliver the broader CPP proposal; and
- 3rd-party hosted "cloud" services increasingly offer an efficient and risk-managed alternative to Aurora Energy building and maintaining all of the elements of its ICT environment

J.4.2. Forecasting Approach

728. Because Aurora's ICT environment is not in a steady managed state today and will require substantial changes both to the capabilities that it delivers and the way in which it delivers them over the CPP period, a traditional base-step-trend approach does not lend itself to the development of Aurora's ICT expenditures. Building on the principles of a base-step-trend forecast, we have developed a bottom-up plan of the minimum work required to keep existing ICT services working, manage risks to continuity of service and deploy new capabilities as required subject to several rounds of peer review and challenge.

729. Reviewing known issues and risks in the current environment, we develop Current State Observations and Focus Areas for each functional area in the business to describe a current state status of known issues and risks in the ICT environment.

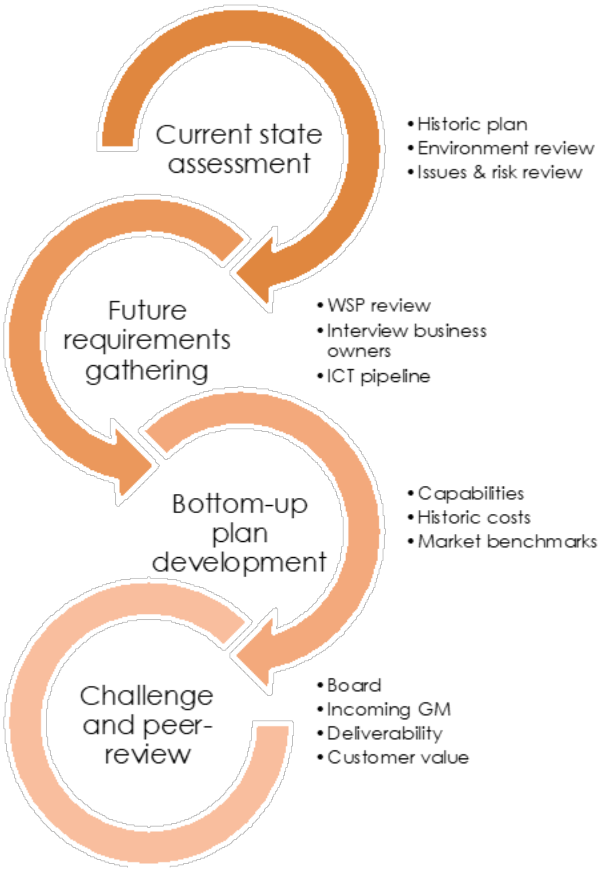
730. Future requirements are derived from external reviews which identified two priority gaps in our ICT capability:

- Data Integrity – strategy to consolidate and make accessible reliable business critical information when and where it's needed and

– Asset Management Tool

731. Both gaps need to be closed as a necessary preconditions for Aurora to be able to progress the initiatives to improve our asset management capability.

732. We developed a greenfield workplan for the 7 years RY20 to 26 of the work required to mediate the risks and issues identified in the current state assessment. The work requirement to meet the plan was developed by breaking ICT supporting each business areas into enabling initiatives and developing a proposed approach and budget by assessing the effort and resource required to document and refine key drivers, benefits and scope into key activities for the initiative.



733. Depending on the type of initiative, a variety of financial forecasting approaches were used to develop work effort estimates (current spend trends, prior similar projects at Aurora and market intelligence) to build a model by key cost component.

734. Estimates were peer-reviewed with documented assumptions & dependencies, what Governance requirements the initiative had and deliverability considerations including risks and dependencies.

735. This long list of activities to manage risks and issues in the current state and meet future requirements was peer reviewed iteratively by the Aurora Executive and ICT team during its development. Once finalised it was further mediated in 3 challenge rounds by:

– Aurora's Board;
– Aurora’s Executive Leadership Team; and
– Aurora's incoming General Manager Digital Transformation.

736. Principal considerations of the challenge rounds were timing and deliverability of the initiatives given the step change in ICT work that the initial bottom-up plan represented.

737. The result of the challenge rounds was to reduce total planned ICT expenditures for the 6 years RY20 to 25 from \$51m to \$37m.

J.4.3. Forecast ICT expenditures

738. Our ICT Capex and Opex is shown in Figure 98 above.

739. Points to note:

- Our focus in RY 20 and 21 is updating the existing infrastructure to minimise the risks and costs of aged assets. In the CPP period, the focus is two-fold:
  - deploying new cyber security management capabilities in response to the increasing risk of cyber-intrusion to the integrity of our ICT services and security of our asset and customer information and
  - establishing a company-wide framework and capability for managing corporate information to eliminate the costs of duplication and improve the quality of our decision making by ensuring that all analysis in the business uses the same source information. Data architecture and the use of modern business intelligence and data analytic tools will form the majority of the ongoing expenditures in this service.
- Where possible, we will deploy these new capabilities in and migrate our existing technology and infrastructure to 3rd-party-hosted cloud services.
- Expenditure for the asset management service peaks in RY21 as we finish updating the asset management tools that have fallen out of vendor support and commission the core EAM. In the CPP period, RY22 Capex spend remains at RY20 levels as we integrate the EAM with the wider Aurora application environment. From RY23 Capex falls as we take advantage of new features in vendor software and cover the lifecycle refresh of hardware and tools that are not available as cloud services.

Box 44: ICT expenditure forecast justification

We are confident that our approach delivers an efficient and prudent level of expenditure because:

- **Clear, prudent drivers:** the planned expenditure is driven by specifically identified business needs
- **Verifiable cost assumptions:** cost assumptions are based on historical costs adjusted for non-recurring items
- **Review and moderation:** Our forecasts are tested and reviewed by executive management and the Board, and the forecasts have been moderated based on feedback and discussion
- **Industry benchmarking:** Benchmarking analysis undertaken at the request of management and the Board shows Aurora's non-network operating expenditure is forecasted to remain below the industry average during the CPP period.

Appendix K. Revenue and Indicative Price Impact

K.1. Introduction

741. This chapter outlines our revenue requirement, how it has been determined and how the revenue requirement and changes to our financial incentives are expected to impact prices.

742. The revenue requirement is determined from the building blocks calculation, with our forecast capital and operating expenditure being key inputs. The revenue requirement provides us with a return on capital employed and a return of capital, along with recovery of operating expenses, taxation and other costs.

743. This chapter summaries the revenue requirement calculation and outlines the key inputs and assumptions applied. Detailed information on how our revenue requirement has been derived is outlined in:

- **Financial and Modelling Information Report.** The Financial and Modelling Information Report details how the revenue requirement is derived, along with the key inputs and assumptions underpinning it.
- **CPP Financial Model.** The CPP financial Model calculates our revenue requirement in accordance with the IMs.

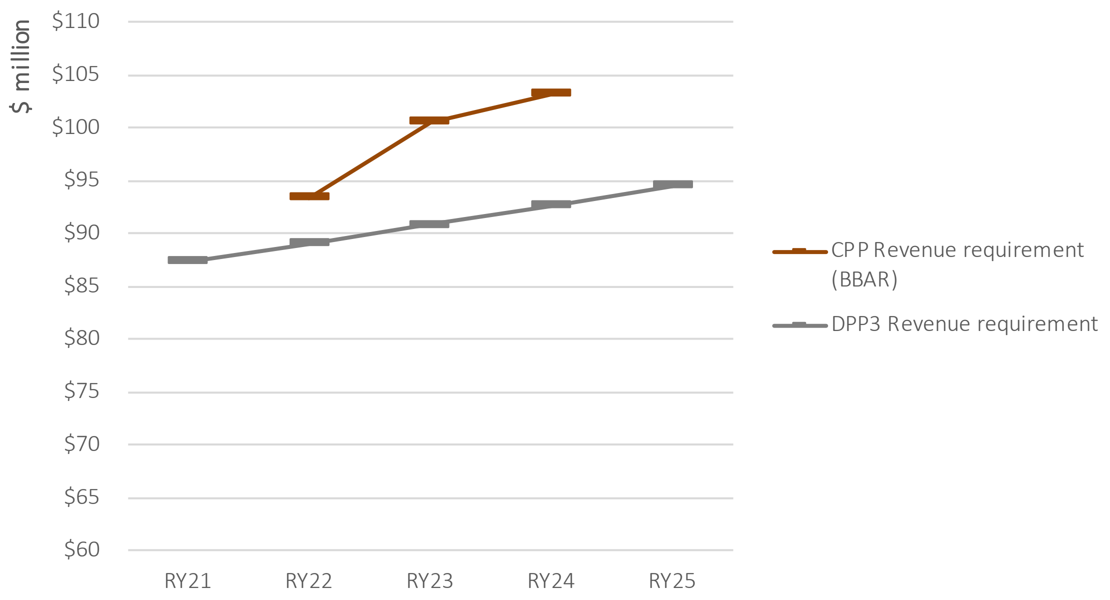
744. The chapter also outlines how we set prices and the price changes we expect for different customer groups in our three pricing regions.

K.2. Revenue Requirement

745. Our investment plans will impact the prices customers pay for our distribution services. If our plan is approved, our revenue will need to increase to cover the additional expenditure.

746. The revenue requirement resulting from our proposed expenditure is outlined in Figure 99.

Figure 99: Revenue requirement (excluding regulatory incentives)



747. The revenue requirement is determined from the IM-specified building blocks calculation which is then smoothed. Revenue smoothing addresses peaks and troughs during the pricing period and allows for the required revenue increase to be phased in.

748. The next section provides an overview of the building blocks calculation and discusses its key drivers. The chapter then outlines how we have smoothed the building blocks allowable revenues to lessen the impact on prices during the early part of the CPP period.

K.2.1. Deriving the Revenue Requirement

749. Our revenue requirement is derived using the IM-specified building block approach. The building block approach recognises that in order to encourage the network investment needed to deliver the safe, reliable distribution services that our customers expect, it is necessary for our revenue to be set at a level that enables us to recover our efficient costs, which includes a reasonable rate of return to investors.

Regulatory requirements

750. We are regulated under Part 4 of the Commerce Act 1986. The Commission promotes the long-term interests of electricity consumers by assessing our proposed expenditure and determining the amount of revenue we can recover.

751. The IMs set out how our revenue requirement is to be derived from our expenditure forecasts through the building blocks approach. They also specify other input assumptions applied in the calculation or the methodologies for determining them.

Expenditure forecasts

752. Our expenditure forecasts make up a large portion of our revenue requirement. As the cost to manage and grow our network increases so does the revenue we need to recover.

753. Operating expenditure has a direct impact on our revenue requirement during the regulatory period in which is incurred. Cost incurred on replacing or creating new assets (capital expenditure) is recoverable over the life of the assets. Accordingly, proposed Capex has an effect on the revenue requirement during the CPP period as well as future regulatory periods.

754. Information on our forecast Opex and Capex is outlined in Appendix D to Appendix J. How the expenditure is incorporated into the building blocks calculation is summarised below. Details of the calculations are outlined in the Financial and Modelling Information Report.

Other building blocks assumptions

755. Our expenditure forecasts are not the only inputs that have an impact on our revenue requirements. The other significant inputs are:

- the value of our existing asset base, which reflects historical investments in the network;
- financial market data, which is used to estimate the cost of capital (WACC) and revaluation rate;
- the corporate tax rate.

756. Each revenue requirement input is either specified in the IMs or the IMs specify how they are determined.

757. Section K.2.2 outlines how each of the significant other input assumptions are determined and applied in the building blocks calculation. Details of other less significant inputs and how they are applied in the calculation are outlined in the Financial and Modelling Information Report.

K.2.2. Building Blocks Allowable Revenue

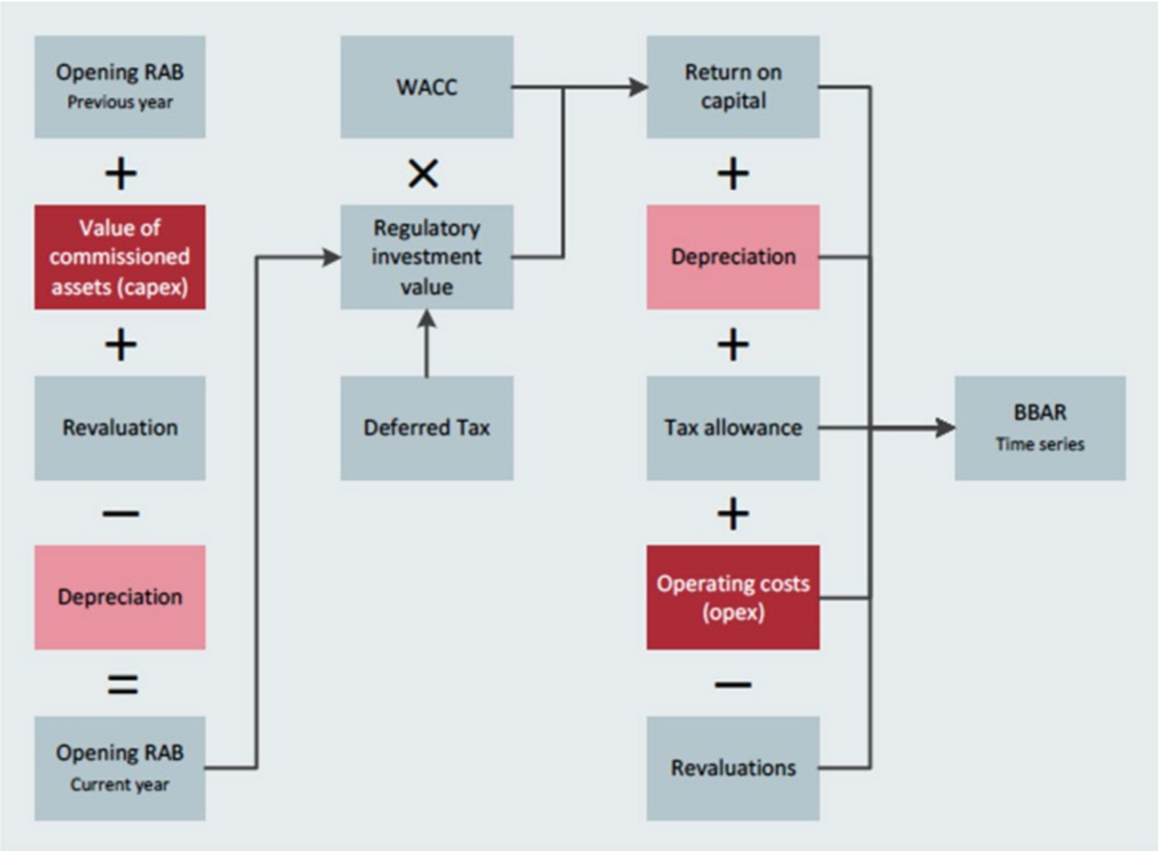
758. The building block approach recognises the different types of costs that we need to recover through our revenue requirement. These costs are:

- our forecast Opex requirements
- return of investment (depreciation or revaluations)
- return on investment (return on capital)
- corporate tax and other costs

759. Figure 100[40] illustrates how the building blocks calculation is applied to derive our revenue.

[40] Source: Commerce Commission. (2019). Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision. 27 November 2019. Figure 5.2, p96.

Figure 100: Overview of how the building block is applied



760. Table 37 outlines the BBAR components included in the revenue requirement calculation. The BBAR and its components are before smoothing, so it differs from the revenue amount that we propose to recover in each year. How we have smoothed the revenue requirement is outlined in section K.2.6.

Table 37: Building block allowable revenue

Category	RY22	RY23	RY24
Return on investment (return on capital)	$26.1m	$29.1m	$32.1m
Depreciation (return of investment)	$20.7m	$23.0m	$24.9m
Revaluations (return of investment)	($11.2m)	($12.6m)	($13.9m)
Operating expenditure allowance	$52.8m	$55.9m	$54.3m
Tax adjustments	$5.3m	$5.7m	$6.4m
Other allowances	($0.5m)	($0.6m)	($0.6m)
Revenue requirement pre-smoothing (BBAR before tax)	**$93.3m**	**$100.5m**	**$103.2m**

761. Table 37 and other tables in this chapter show our revenue requirement and its components for a three-year CPP period beginning RY22. As outlined in section 4.1 we are proposing a three-year CPP period.

762. Appendix B of the Financial and Modelling Information Report outlines the RY25 and RY26 BBAR and revenue smoothing information. This information will apply in the determination of prices should the Commission determine a period greater than three years.

763. The remainder of this section briefly explains each of the components that comprise the BBAR with the exception of our operating expenditure which has already been explained.

K.2.3. Return on Investment

764. As electricity distribution is an asset-intensive business, the return on investment is a significant component of our revenue requirement. The return on investment component is determined by applying an estimate of a reasonable rate of return (cost of capital) to our assumed capital investment (regulatory investment value). Table 38 sets out our return on investment assumptions.

Table 38: Return on investment assumptions

Category	RY22	RY23	RY24
Opening RAB	$559.5m	$632.0m	$694.8m
Deferred tax	($28.1m)	($32.7m)	($37.9m)
Regulatory investment value	**$531.4m**	**$599.3m**	**$656.9m**
Assets commissioned	$82.7m	$73.7m	$91.3m
Cost of capital	4.57%	4.57%	4.57%

765. Table 39 sets out the calculation of our regulatory asset base (RAB); it shows how the opening RAB is rolled forward each year to reflect the new assets commissioned, depreciation during the year, asset revaluations and disposals. Assets only enter the RAB once they are commissioned, and therefore customers only pay for these assets once they are in use.

Table 39: RAB roll forward

Category	RY22	RY23	RY24
Opening RAB	$559.5m	$632.0m	$694.8m
Assets commissioned	$82.7m	$73.7m	$91.3m
Depreciation	($20.7m)	($23.0m)	($24.9m)
Revaluations	$11.2m	$12.6m	$13.9m
Disposals	($0.6m)	($0.5m)	($0.4m)
Closing RAB	**$632.0m**	**$694.8m**	**$774.6m**

766. The cost of capital is an estimate of the reasonable rate of return that an investor expects to earn on an investment that has the same risk as our regulated assets. Under the Commission's IMs, the rate of return is defined as a weighted average of the cost the debt and equity used to fund the regulated assets. This is referred to as the weighted average cost of capital (WACC).

767. In accordance with IM clause 5.3.22, the WACC applied to calculate our revenue requirements is consistent with the WACC applied in the Commission's default price-quality path decision for the same period[41]. Our proposed WACC is set out in Table 40.

Table 40: Cost of capital assumption

	RY22	RY23	RY24
Cost of capital	4.57%	4.57%	4.57%

K.2.4. Depreciation and revaluations

768. Depreciation or 'return of capital' allows investors to recover their investment over the life of the assets. Depreciation is based on the regulatory value of each asset and assumed asset life. The IMs specify the asset life that are applied to each type of asset in the determination of depreciation.

769. Each year, the RAB is escalated by inflation. This ensures that the value of the RAB is not eroded by inflation. As shown in Table 37, the revaluation amount is treated as income and deducted from our revenue requirement. The revaluation percentages applied in the revaluation calculation are shown in Table 41.

Table 41: Forecast revaluation rate

	RY22	RY23	RY24
Revaluation rate	2.0%	2.0%	2.0%

K.2.5. Tax and other adjustments

770. Tax is an important cost item that is faced by businesses, including electricity distributors. It is therefore essential to provide an allowance for tax when determining our revenue requirement.

771. The tax amount could be calculated either by treating regulatory depreciation as a deductible expense (the 'tax expense' approach) or, alternatively, taking account of the allowable tax depreciation in accordance with the lax legislation (the 'tax payable' approach).

772. The 'tax expense' approach would benefit electricity distributors compared to the 'tax payable' approach, because the tax law provides for assets to be depreciated more quickly compared to regulatory depreciation. As a result, a tax expense approach provides the distributor with a timing benefit compared to the 'tax payable' approach.

773. To remove this benefit, the Commission combines a 'tax expense' approach with a regulatory tax adjustment. The regulatory tax adjustment therefore reduces our revenue requirement to account for this timing difference. The Commission has previously explained that this approach ensures that

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41 Commerce Commission. (2019). Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price quality path. 25 September 2019.

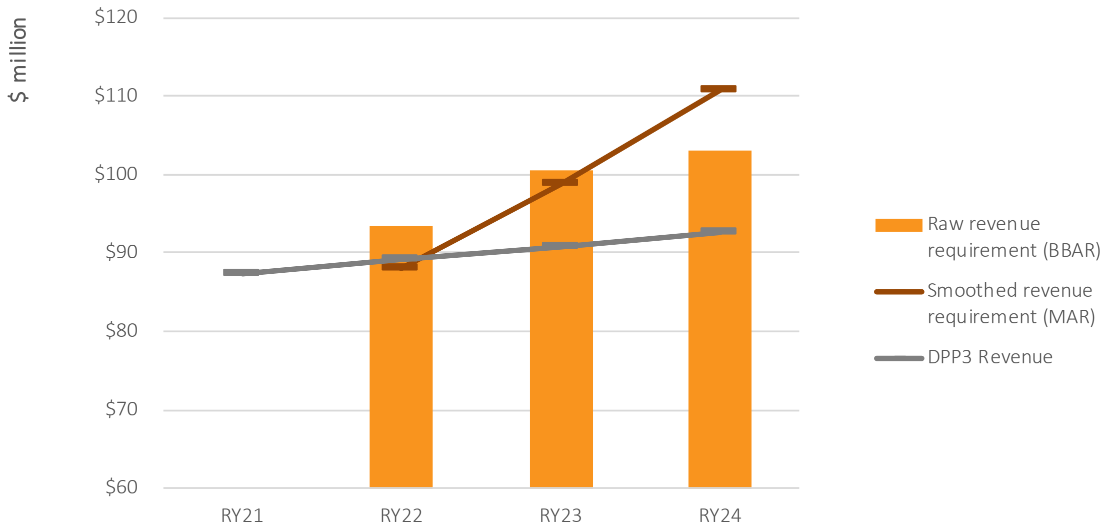
our expected returns to shareholders are consistent with those expected in a workably competitive market.

K.2.6. Revenue Smoothing

774. Revenue smoothing seeks to manage the price impact on customers by adjusting the 'raw' or 'unsmoothed' revenue (BBAR) to be recovered in each year. The overall effect of these adjustments is zero in present value terms, so that customers are no better or worse off as a result.

775. Figure 101 shows the unsmoothed and smoothed revenues for the three-year CPP period.

Figure 101: Revenue smoothing (excluding regulatory incentives)



776. We have listened to our customers and stakeholders in considering how best to smooth our revenue recovery over the CPP period. The Customer Advisory Panel (CAP) highlighted that customers take time to modify their electricity usage, including in managing their energy use in response to increased prices. Accordingly, they advocated a slower rate of increase in our charges at the start of the CPP period to provide customers with additional time to respond to the higher prices.

777. The IM requirements include a mechanism (X factor adjustment) that determines when revenue increases are recognised. To allow for the same present value equivalent total revenue over the pricing period, the application of the X factor mechanism also impacts the increase in revenue requirement at the beginning of the period, whereby a higher increase during the period reduces the impact of increases at the beginning of the period.

778. In response to our customer and stakeholder feedback we propose a high X factor (-10%) to limit the impact on prices at the beginning of the CPP period. Further information on our proposed X- factor is given in section 4.3, above.

K.3. Indicative Prices

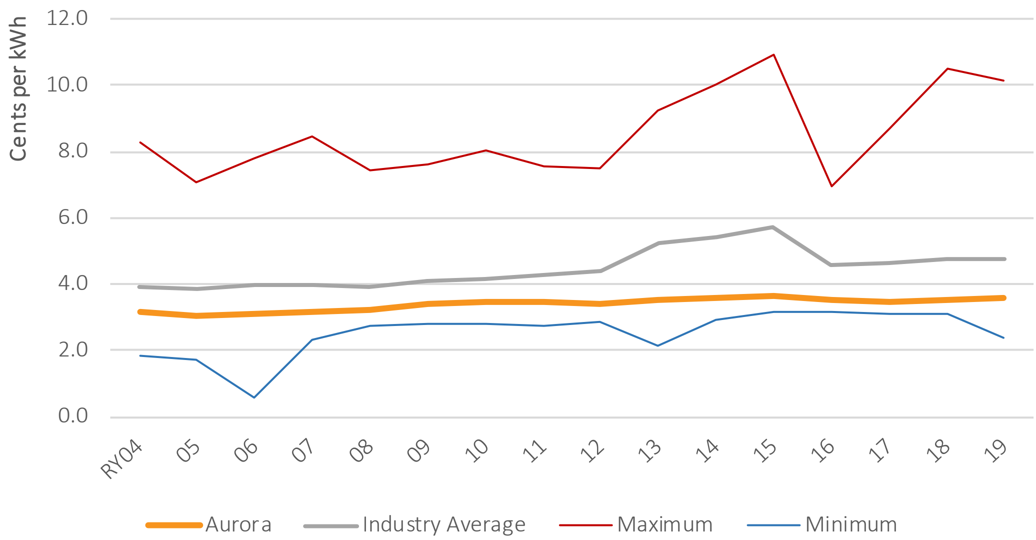
K.3.1. Historic Prices

780. Aurora Energy has previously acknowledged that historic investment levels have been insufficient, over an extended period prior to 2017, leading to gradual deterioration of asset health across a range of asset fleets. Since our allowable revenue, set by the Commission under price-quality regulation, is directly related to historic expenditure, Aurora Energy's distribution prices have, on average, been among the lowest in the country. While it is difficult to directly compare the distribution prices of different EDBs owing to the very different pricing structures that prevail, we can assess differences based on high-level measures:

- Dollars of revenue per ICP;
- Dollars of revenue per MW of coincident peak demand; and
- Cents of revenue per kWh of electricity delivered.

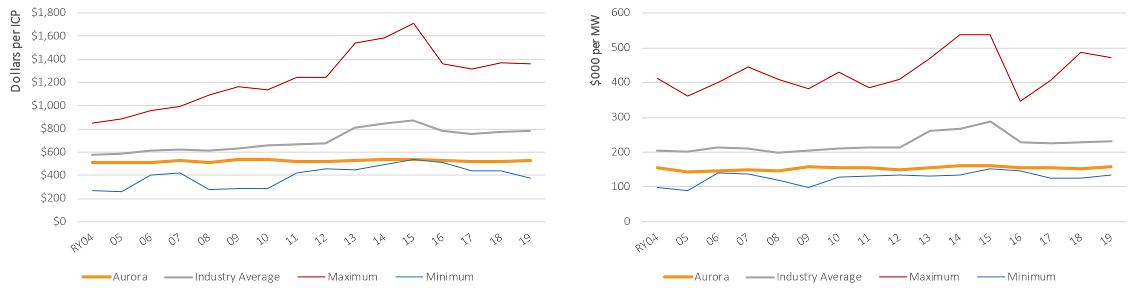
781. Figure 102, below, shows Aurora Energy's average distribution revenue, on the basis of cents per kWh of electricity delivered to consumers (constant 2004 cents), against the industry average, maximum and minimum . The chart clearly shows that, as a consequence of low historic investment, Aurora Energy's distribution charges have remained among the lowest in the country, and virtually flat in real terms.

Figure 102: Distribution component of revenue - constant 2004 cents per kWh delivered



782. The position is not materially changed when measured on the basis of revenue per MW of coincident peak demand or revenue per ICP, as demonstrated by Figure 103, below.

Figure 103: Distribution component of revenue - constant 2004 dollars per ICP (L), per MW of demand (R)



K.3.2. Our Pricing Methodology

783. Our current pricing methodology has been developed in accordance with pricing principles set by the Electricity Authority. The Electricity Authority focusses on the extent to which distributors' pricing methodologies are service-based and cost-reflective. We consider that our approach to pricing is as cost-reflective as we can currently make it, despite the fact that our residential pricing remains based on energy consumption. In the Electricity Authority's 2019 baseline assessment of distributors' pricing methodologies, our pricing approach was rated among the leading group of distributors .

Pricing Regions

784. A key feature of our pricing approach is disaggregation into three pricing regions; Dunedin, Central Otago and Wanaka, and Queenstown. Our selection of pricing areas is informed by three criteria:

- Whether candidate pricing areas readily defined and identifiable (from the perspective of network layout, rather than geography or arbitrary boundaries)
- Whether there areas that are interconnected and able to provide mutual support, and therefore candidates for a consolidated pricing area
- Whether there adjoining areas with similar network characteristics that would make them candidates for a consolidated pricing area

785. Aurora Energy has five Transpower grid exit points (GXPs) that provide supply to our distribution networks:

- Halfway Bush (HWB), serving northern Dunedin and the Taieri Plain;
- South Dunedin (SDN), serving southern Dunedin;
- Clyde (CYD), serving Alexandra, the Teviot Valley, the Manuherikea Valley, and the Ida Valley;
- Cromwell (CML), serving Cromwell, the Upper Clutha, Wanaka, and the Lindis Valley; and
- Frankton (FKN), serving the Wakatipu Basin.

786. The Dunedin network is interconnected, and there is an ability to provide some support between each of the GXP areas. Therefore, the areas of network served by the South Dunedin and Halfway Bush GXPs are consolidated into the Dunedin pricing area.

787. The areas of our network in Central Otago, which are served by the Clyde, Cromwell, and Frankton GXPs, are all separate, with no interconnecting assets. This would logically lead to three pricing areas; however, on acquisition of the Central Electric network in 1999, Aurora Energy decided that the similar, low density, rural, nature of the networks served by the Clyde and Cromwell GXPs made it feasible to consolidate into a single pricing area, despite that neither area is connected and therefore unable to provide mutual support. This was a logical decision, at the time, since the two areas are adjoining and had similar network characteristics. The recent rapid growth of Wanaka and Cromwell starts to call into question whether Clyde and Cromwell should be separated into their own pricing areas; however, the customer density of each still remains comparatively similar (Cromwell - ~8 connections per km of network circuit, and Clyde ~6 connections per km of network circuit).

788. Our maximum allowable revenue is allocated to each region in a manner that reflects the costs of serving customers in that region. In considering how costs should be recovered from pricing areas, it is important to understand that there are three categories of costs that need to be considered:

- Networks costs;
- Non-network costs; and
- Pass-through and recoverable costs.

789. Network costs are those costs that are attributable to physical network assets and include the costs of providing and renewing assets (return on investment, depreciation, etc), and the cost of maintaining assets (fault response, inspections, servicing, vegetation management, etc.).

790. Non-network costs cover the people, premises, ICT systems and other business infrastructure associated with operating and providing support to the business. These are a mix of asset, maintenance, and operations related costs.

791. Pass-through and recoverable costs are those costs associated with other inputs to the business and over which we generally have little or no control. These include transmission expenses payable to Transpower for operating the national grid, local authority rates, and regulatory/industry levies. They also include various regulatory incentives.

792. Our pricing philosophy is that there should be no cross-subsidy between pricing area unless it is well-reasoned and can be objectively justified. In terms of the cost types described above, we consider that:

- Network costs should fall where they lie. That is, the costs of providing and maintaining network assets should be attributed to the area that benefits from their use. Therefore, because there is no interconnection between the parts of our network that are served by the various GXPs, there should be no sharing of network costs. For example, costs arising within Dunedin should not be shared with the Wakatipu basin (Frankton) . We note, of course, that due to the topological similarities of the networks served by the Clyde and Cromwell GXPs, explained above, we have consolidated those network areas into a single pricing area. Due to such similarities, we consider that consolidation can occur without unduly compromising allocation principles.

- Non-network costs should be allocated across the entire customer base. This allows customers to reap the benefits of scale, whereby the allocated cost is less than if the pricing area was a stand-alone business. For example, if each pricing area was a stand-alone business, each would need to provide separate control rooms, ICT infrastructure, management and staff, etc.
- Pass-through and recoverable costs require a hybrid approach. Some costs types should be allocated across the business, while others should be allocated more precisely to pricing areas. For example, transmission expenses are readily attributable to pricing areas, because they are related to GXPs. Regulatory incentives are another example. In the current pricing year, we are required to pass $18.5 million back to consumers under the Commission's IRIS incentive scheme. We incurred this penalty because, in the last regulatory period (1 April 2015 to 31 March 2020), we needed to spend more than the expenditure limits imposed by the Commission . Because expenditure is directly related to prices, we allocated that refund to pricing areas in the same proportion as the aggregate revenues recovered from each pricing area in the previous year. Simply put, those customers that had paid more in RY2020 receive a greater share of the refund in RY2021.

Prices

793. The next stage of our pricing methodology is to allocate the revenue to be recovered from each region to the different load groups in that region. Each pricing area has seven principal load groups, and a small number of minor load groups that include more specialised connection types; for example, unmetered distributed loads.

794. Once the revenue to be recovered from each region's load group has been determined, we must adjust the relevant network tariffs to recover the target amount. The price setting process requires us to forecast the relevant quantities to which the network tariff components apply, such as customer numbers (in relation to fixed charges); control period demand (in relation to peak charges); or kilowatt hours (in relation to volumetric charges). Only Aurora Energy's Residential customers are charged on the basis of volumetric consumption. Our pricing for General (non-Residential) customers is more complex, with connections in larger load groups having up to five pricing components recovering distribution costs, and two pricing components recovering pass-through and recoverable costs, making seven pricing components in total.

795. To implement the pricing methodology, we are therefore required to forecast the relevant quantities to which each network price applies.

796. Whether prices are high or low depends on the ratio of revenue to chargeable quantities:

- prices are relatively low in the Dunedin pricing area owing to the fact that, although allocated revenue is high (recovering 48% of total network costs), that revenue is spread over 58% of the network's total chargeable quantities;
- prices are relatively high in the Central Otago pricing area because, although allocated revenue is lower (recovering 34% of total network costs), that revenue is spread over a much smaller percentage of the network's total chargeable quantities (22%).

- Prices in the Queenstown pricing area fall somewhere in between, with the revenue allocation comprising 18% of the total and chargeable demand comprising 20% of chargeable quantities.

797. Our pricing methodology, available from www.auroraenergy.co.nz, sets out in detail how we apply these principles in practice.

798. Pricing quantities and allocators are updated over time and cannot be forecast with certainty beyond the short-term. At this stage, we are only able to provide indicative information on the price impacts of our CPP proposal, as presented below.

K.3.3. Indicative Pricing Model

799. Pricing is a complex and relatively time-consuming exercise. Our annual price setting process normally starts in November, and concludes in the first week of February when prices are notified to electricity retailers. The time involved, and the diminishing accuracy of forecasting pricing allocators several years out, means that our normal pricing procedures are not useful for estimating the probable pricing impact of our proposal over the three-year CPP period. Recognising this constraint, we developed an indicative pricing model.

800. The indicative pricing model uses a number of simplifying assumptions to quickly approximate the output of our corporate pricing model, and provide an indication of the pricing impact that our CPP proposal will produce for consumers in each pricing region. Additionally, we elected to consolidate our load groups into residential, small, medium and large business customer groups. We categorised these consolidated customer groups as shown in Table 42 below.

Table 42: Consolidated consumer categories

Category	Attributes
Residential customers	8kVA and 15kVA residential connections on volumetric pricing
Small business customers	Customers with connection capacities between 1kVA and 149kVA
Medium customers	Customers with connection capacities between 150kVA and 499kVA
Large customers	Customers with connection capacities of 500kVA and above

801. By necessity, this aggregation introduces a degree of averaging; however, for the reasons outlined above, it was not possible to produce a suite of forecast tariffs that would reflect the pricing outcomes of our CPP proposal. We also recognised that, for the medium and large customer groups, the pricing outcome would vary significantly according to both capacity and demand. For this reason, we only presented average pricing for residential and small business customers in our consultation document. Our consultation channels encouraged larger businesses to discuss their future pricing forecasts directly with us.

K.3.4. Regulatory Incentives

802. We faced a significant dilemma when we prepared the pricing information we included in our consultation document. The regulatory price setting process focusses on determining a revenue path that reflects our past investments, as well as forecast of our expenditure needs through the CPP period, as described above. However, in Aurora's case, we were facing significant regulatory incentive adjustments attributable to the IRIS. This had the potential to severely distort the prices that our customer would face.

803. The IRIS is an expenditure efficiency incentive. It is designed to provide distributors with an incentive to constrain expenditure to the forecast capital and operating expenditure allowances determined by the Commission when setting the DPP. The underlying premise of the IRIS is that the expenditure allowances set as part of the DPP are reasonable and adequately reflect the needs of the EDB in question. Broadly speaking, when an EDB underspends its expenditure allowances, it is able to keep a portion of the savings for a period of five years before those savings are fully shared with consumers. Conversely, where an EDB overspends its expenditure allowances, it must bear a portion of those costs for five years before the overspend is reflected in prices.

804. In Aurora's case, we needed to significantly increase our expenditure, from January 2017, in order to start to remediate assets in poor condition and which were posing increasing safety concerns, as well as build our internal capacity and capabilities as a stand-alone business. This resulted in both our Capex and Opex allowances being exceeded significantly, resulting in us facing very large negative IRIS adjustments (penalties) from the commencement of the third DPP period (DPP3) on 1 April 2020.

805. For the purposes of this discussion, we ignore the Capex IRIS incentive. This remains unchanged under the transition from a DPP to a CPP and is less significant when compared to the Opex IRIS incentive for two reasons:

- capital expenditure is recovered over a long period, typically 40 to 70 years depending on the asset type; and
- the retention factor set for the second DPP (DPP2) was relatively modest at 15%.

806. The Opex IRIS incentive is more significant because operating expenditure flows directly to prices and the retention factor set for DPP2 was set at approximately 34%.

807. A feature of the IRIS incentives is that the CPP Opex IRIS differs to the DPP Opex IRIS. This is because a CPP breaks the link between expenditure levels provided for in the prior regulatory period and those included in a CPP. This link is relied on in the DPP IRIS mechanism. Without additional adjustments in the CPP IRIS, temporary over-spend in the penultimate year of the DPP is inaccurately treated as permanent over-spend. The solution is to treat the difference between forecast Opex and actual Opex in the penultimate year of the prior period as temporary not permanent.

808. The result of the different treatment of the Opex IRIS under the DPP and CPP means that we faced a very significant negative incentive adjustment in the first year of DPP3 ($18.5 million in 2021) and then we would transition to the CPP where the incentive adjustment would be strongly positive (so strong, in fact, that we have applied for a variation to the IMs to allow us to spread the IRIS impact

over 8 years, instead of just the 3 years of the CPP period – refer to section 3.6, above, for the specific details of the variation).

809. While we could have simply focussed on the revenue path that would result from our CPP proposal, we considered that this would not provide consumers with the full picture of how their distribution charges might change. Accordingly, we elected to present pricing outcomes inclusive of regulatory incentives.

K.3.5. Indicative Price Impacts - General

810. Set out below are indicative increases to average monthly distribution line charges for our CPP proposal, compared with staying on the default price path. These estimates are shown both inclusive and exclusive of regulatory incentive adjustments.

811. The actual charges faced by customers will depend on the outcome of the Commission's process, how each individual customer uses the electricity network, and any updated inputs to our pricing methodology as new data becomes available.

812. The sections below provide further details of the implications for residential and small business customers in each of the pricing regions. For larger business customers, pricing is more sensitive to the characteristics of individual electricity connections, and so it is not practical to present similar analysis in any meaningful way.

K.3.6. Indicative Price Impacts - Dunedin

813. Table 43, below, provides indicative monthly distribution charges for residential and small business customers in Dunedin, exclusive of regulatory incentives.

Table 43: Dunedin – average monthly impact on distribution charges in constant 2020 dollars (excluding regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$42	$42	$45	$49
Small Business	$111	$109	$118	$127
If we stay on DPP				
Residential	$42	$42	$41	$41
Small Business	$111	$110	$108	$107
Difference under our CPP				
Residential	n/a	$0	$4	$8
Small Business	n/a	($1)	$10	$20

814. Table 44, below, provides indicative monthly distribution charges for residential and small business customers in Dunedin, including the forecast impact of regulatory incentives.

Table 44: Dunedin – average monthly impact on distribution charges in constant 2020 dollars (including regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$32	$46	$49	$53
Small Business	$85	$120	$129	$138
If we stay on DPP				
Residential	$32	$33	$34	$37
Small Business	$85	$87	$89	$98
Difference under our CPP				
Residential	n/a	$13	$15	$16
Small Business	n/a	$33	$40	$40

815. We estimate that the 3-year increase in the total average residential total power bill (including incentives and other pass-through and recoverable costs) for Dunedin customers would be 11.9% between 2021 to 2024 under our proposed CPP plan, compared to 2.8% if we stayed on a default price path. As a result, the total power bill would increase by $20 per month for the average residential household in Dunedin.

K.3.7. Indicative Price Impacts – Central Otago & Wanaka

Table 45, below, provides indicative monthly distribution charges for residential and small business customers in Central Otago and Wanaka customers, exclusive of regulatory incentives.

Table 45: Central Otago and Wanaka – average monthly impact on distribution charges in constant 2020 dollars (excluding regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$78	$75	$80	$86
Small Business	$125	$120	$129	$138
If we stay on DPP				
Residential	$78	$76	$74	$72
Small Business	$125	$122	$119	$115
Difference under our CPP				
Residential	n/a	($1)	$6	$14

Small Business	n/a	($2)	$10	$23

816. Table 46, below, provides indicative monthly distribution charges for residential and small business customers in Central Otago and Wanaka customers, including the forecast impact of regulatory incentives.

Table 46: Central Otago and Wanaka – average monthly impact on distribution charges in constant 2020 dollars (<u>including</u> regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$62	$81	$87	$92
Small Business	$99	$130	$129	$148
If we stay on DPP				
Residential	$62	$62	$62	$66
Small Business	$99	$99	$99	$105
Difference under our CPP				
Residential	n/a	$19	$25	$26
Small Business	n/a	$31	$30	$43

817. We estimate that the 3-year increase in the total average residential total power bill (including incentives and other pass-through and recoverable costs) for Central Otago and Wanaka customers would be 16.7% between 2021 to 2024 under our proposed CPP plan, compared to 2.1% if we stayed on a default price path. As a result, the total power bill would increase by $30 per month for the average residential household in Central Otago and Wanaka.

K.3.8. Indicative Price Impacts - Queenstown

818. Table 47, below, provides indicative monthly distribution charges for residential and small business customers in Queenstown customers, exclusive of regulatory incentives.

Table 47: Queenstown – average monthly impact on distribution charges in constant 2020 dollars (excluding regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$59	$56	$61	$67
Small Business	$98	$94	$102	$112
If we stay on DPP				
Residential	$59	$57	$56	$55
Small Business	$98	$96	$95	$93
Difference under our CPP				
Residential	n/a	($1)	$5	$12
Small Business	n/a	($2)	$7	$19

819. Table 48, below, provides indicative monthly distribution charges for residential and small business customers in Queenstown customers, including the forecast impact of regulatory incentives.

Table 48: Queenstown – average monthly impact on distribution charges in constant 2020 dollars (including regulatory incentives)

	RY21	RY22	RY23	RY24
Under our CPP proposal				
Residential	$47	$60	$65	$71
Small Business	$79	$101	$109	$119
If we stay on DPP				
Residential	$47	$47	$47	$51
Small Business	$79	$79	$80	$85
Difference under our CPP				
Residential	n/a	$13	$18	$20
Small Business	n/a	$22	$29	$34

820. We estimate that the 3-year increase in the total average residential total power bill (including incentives and other pass-through and recoverable costs) for Queenstown customers would be

10.6% between 2021 to 2024 under our proposed CPP plan, compared to 1.5% if we stayed on a default price path. As a result, the total power bill would increase by $24 per month for the average residential household in Queenstown.

K.3.9. Relativity with Other Infrastructure Providers

821. The catalyst for our CPP Application is a need to prudently invest in our assets and operations, to ensure that our network remains safe, to arrest declining service performance, to continue to service growth, and to position our network for evolving use by consumers. We are undeniably catching up on a back-log of needed investment, especially in asset renewals.

822. Elevated expenditure levels will give rise to an increased revenue requirement, and will result in higher prices for the services we perform. While we acknowledge that pricing step-changes are challenging, this CPP will not see us out of step with other owners of significant infrastructure in our region.

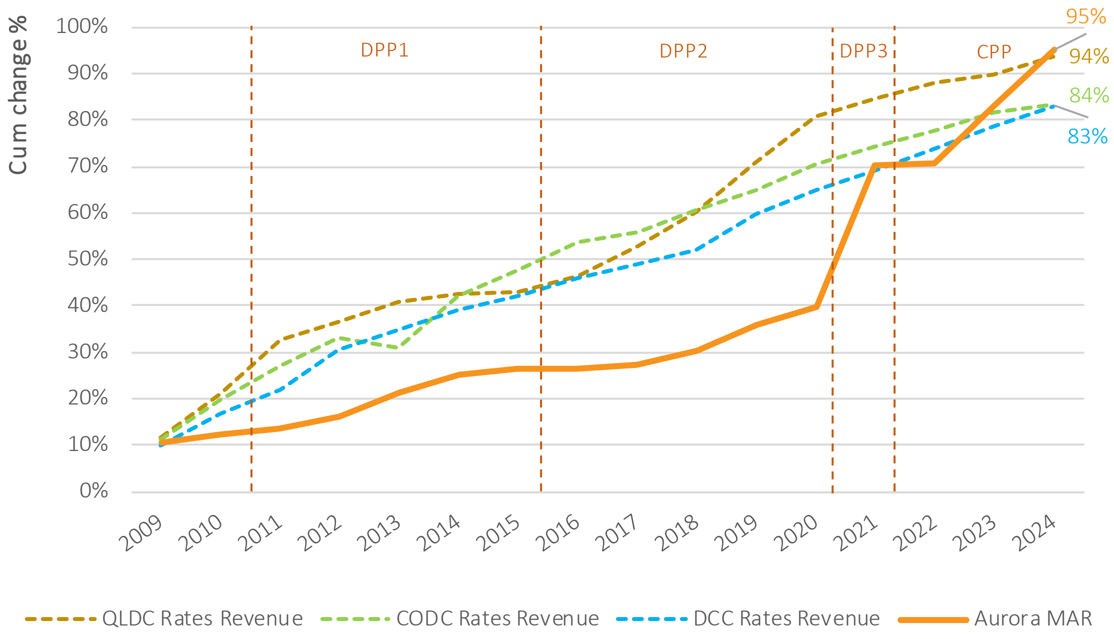
823. Local Authorities are responsible for providing a wide range of infrastructure and other services, not dissimilar electricity networks – roads, lighting, water treatment and delivery, sewerage and refuse collection, treatment and disposal. Although local authority rates are relatively low compared to total revenue (between 38% and 52% of operating revenue),[42]with the shortfall being made up from user charges, development contributions, subsidies and other sources of income, rates are not dissimilar to line charges in that they apply ubiquitously across the community.

824. We have examined the historic and forecast rates revenue of the three local authorities within our network boundary – Queenstown Lakes District Council (QLDC), Central Otago District Council (CODC), and Dunedin City Council (DCC). Our analysis shows that, although our revenue change profile is different to Council's, when our CPP period concludes, the cumulative change in our revenue will not be materially out of step with the cumulative change in rates revenue of local Councils, as shown in Figure 104[43], below.

[42] QLDC, CODC, DCC Annual Reports 2018/19. Available from each respective Council's website.

[43] Data sources for this analysis are; Aurora Energy's revenue - historic information disclosures (https://www.auroraenergy.co.nz/), the Commission's DPP3 determination, Councils' rates revenue – the annual plans, 10-year plans, and 2018/19 annual reports of each respective council, and Statistics New Zealand Infoshare (https://www.qldc.govt.nz/, https://www.codc.govt.nz/, https://www.dunedin.govt.nz/, and http://archive.stats.govt.nz/infoshare/, respectively.

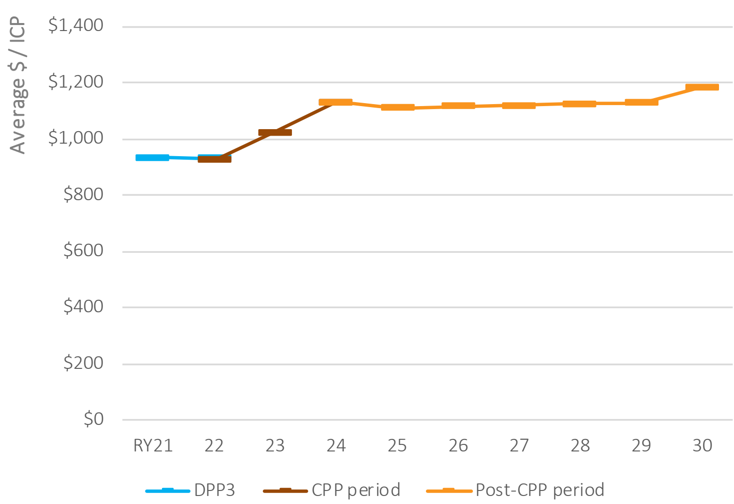
Figure 104:Aurora Energy historic and forecast revenue versus historic and forecast QLDC, CODC and DCC rates



K.3.10. Long-term Pricing Impact

825. We have considered how prices may evolve over the longer-term as a consequence of this CPP and subsequent investment periods. As explained in section 4.1, we have challenges in forecasting expenditure requirements with sufficient precision beyond our proposed three-year CPP proposal, and there are greater challenges in forecasting connection numbers and load group parameters with sufficient certainty to provide meaningful pricing information in the form provided in the table above. Owing to these limitations, we consider that the long term pricing impact on our customers is best represented at an average network level ($ per ICP), as illustrated in Figure 105.

Figure 105: Forecast long-term pricing impact (excluding regulatory incentives)



K.3.11. A Final Word on Pricing - Evolution

826. While we have presented indicative pricing that is consistent with our pricing methodology, we expect that our pricing methodology will evolve over time, particularly in response to the Electricity Authority's incentives to implement more service-based and cost-reflective distribution pricing. In our CPP consultation, our Central Otago customers told us that they dislike our regional pricing. Given this feedback, we intend to undertake a strategic review of our pricing methodology to determine whether an alternative pricing approach could, or should, be developed.

827. With the assistance of expert advice, we expect to publish a roadmap toward assessing whether we could introduce more cost reflective pricing that is supported by our customers and stakeholders. Significant modelling and analysis will be required, to demonstrate that any proposed pricing approach is sustainable, and does not result in unintended consequences. We are aiming to be in a position to consult with customers and stakeholders on our options in 2023.

Box 45: Revenue and pricing summary

Our forecast revenues have been derived in accordance with the building blocks rules set down by the Commission in its input methodologies.

Our building blocks allowable revenue reflects our forecast investment in network infrastructure, technology and people, so we can continue to provide safe and reliable delivery of electricity, and to position the business to adapt to evolution in the way our customers use the network.

The forecast change in our revenue from the DPP, from both a starting revenue and annual rate-of-change perspective, is not outside the ranges produced in past price-quality determinations; however, the operation of regulatory expenditure incentives, based on lower than needed expenditure allowances in DPP2, dominates pricing affects.

Our indicative pricing analysis produces different pricing outcomes for our three pricing regions, consistent with the cost-reflective nature of our pricing methodology, and shows that the additional costs to our customers of our CPP proposal compared to the Commission's DPP3 decision, over the same 3-year period, are approximately:

- $19 per month for an average residential customer
- $40 per month for an average small business customer.

Appendix L. Quality and Service Standards

832. This chapter outlines our proposed quality standards for the CPP period, along with the corresponding quality incentive. We describe the approach taken to model and forecast the quality performance of the network throughout the CPP period.

L.1. Overview

833. Our past reliability performance his historically compared favourably with our peers, as shown in Figure 10 and Figure 11, below[44].

Figure 106: Historic SAIDI performance

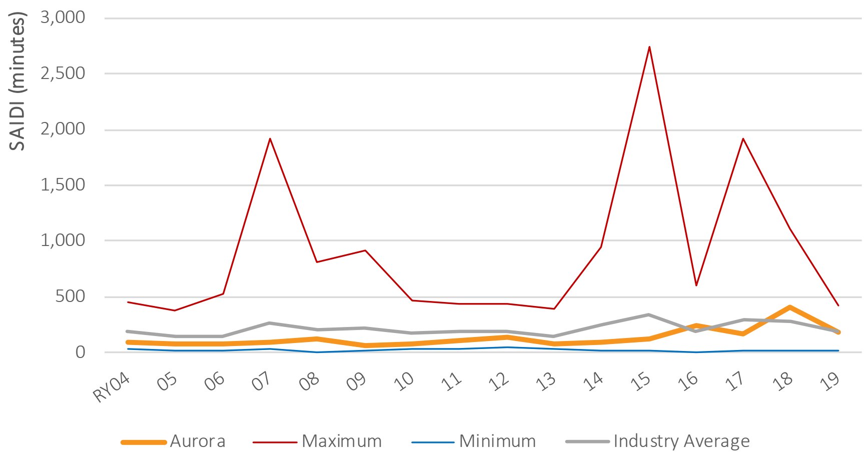
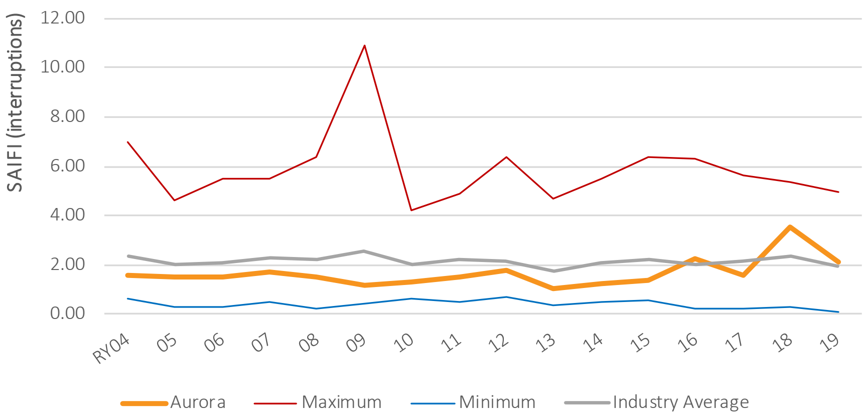


Figure 107: Historic SAIFI performance



834. Our reliability performance has been well below the industry for many years, we have seen a deteriorating trend in recent years which has led to breaches of our regulatory compliance limits in 2012 and 2016 to 2019. While our reliability performance is now close to average, we cannot afford

[44] PricewaterhouseCoopers. Electricity information disclosure compendia

to continue to breach our reliability limits and sustain the pecuniary penalties that accompany that state of affairs.

835. We support the Commission's principle in its recent DPP3 decision that there should be 'no material deterioration' in network quality. Our CPP proposal is centred around this principle and the Commission's latest thinking on quality standards, which we support to the extent that the DPP quality standards are designed for businesses in a ‘steady state’.

836. Our customers have told us they expect us to provide a reliable electricity supply and be safety conscious. Approximately 90% of the residential and business customers we surveyed described these attributes as 'essential'. They have also told us that while reliability is very important, price increases are a greater concern at this time.

837. Therefore, our immediate focus is on delivering better safety outcomes through improved asset health. This is likely to result in a modest consequential reliability improvement that will put us on track to meet customers' reliability expectations in the medium term, which is beyond the forthcoming CPP period.

838. Although our actual reliability performance compares favourably with our peers, it has exhibited a deteriorating trend in recent years which has led to compliance breaches. We are committed to arresting this decline in the short term and delivering reliability performance in the medium term that will meet our customers' expectations. We know that turning around reliability performance is not just about asset investment. It also requires improved analytics, investigation, operational response and enhanced communication to ensure that our limited resources are channelled to maximum effect.

839. With the above observations in mind, and with the strong support of our Board, we have established a Reliability Management Plan to ensure that levers with the potential to affect reliability performance and customer service are actively managed by the business. In total, we have identified 39 levers which span each of the business's functional areas. Our Reliability Management Plan is supported by a governance process that prioritises and monitors actions that are expected to drive reliability improvements.

840. We have improved our modelling capability to forecast reliability performance, measured by SAIDI and SAIFI. Improving our analytical capability in this area assists us in understanding the root causes of our reliability performance and identifying the optimum improvement initiatives, given our resource constraints. In addition, our modelling has informed the setting of our CPP proposal. This process has also highlighted the gaps in our current knowledge and reinforced the inherent uncertainty in forecasting future reliability performance.

841. Our quality proposal for the CPP period focuses on stabilising recent reliability performance in the short term and establishing a foundation for returning, subject to consumer support, to higher levels of reliability in the medium term.

L.2. Historical Performance

842. This section sets out the historical network reliability performance and compares the performance to the targets set by the Commission in its Default Price-Quality Path Determinations. Historical data from RY09 to RY20 is presented to demonstrate the long-term trend in network performance.

843. For simplicity, the data has been shown in two groups in the charts:

- RY16 to RY20 is denoted DPP2
- All years prior to DPP2 have been denoted as DPP1, noting that DPP1 dates were actually RY11 to RY15.

L.2.1. SAIDI

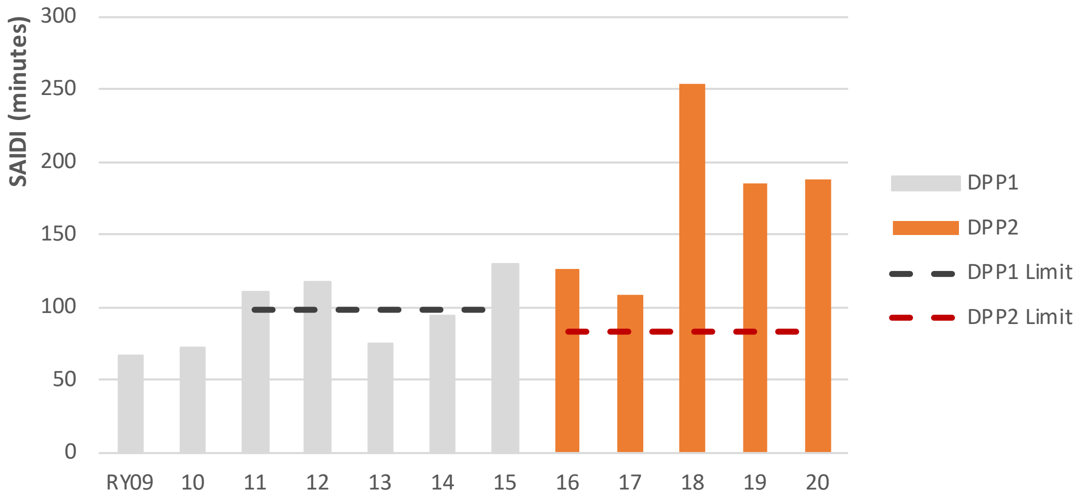
844. During DPP2, network performance was reported as the sum of normalised unplanned SAIDI plus normalised planned SAIDI. where:

- Normalised unplanned SAIDI was adjusted to replace SAIDI incurred during Major Event Days (MEDs) with the MED Boundary Value and to exclude other excludable events.
- Normalised planned SAIDI was adjusted to de-weight the SAIDI incurred by 50%.
- An unplanned interruption is any interruption where there was less than 24 hours' notice, or no notice, provided to the public or all consumers affected by the interruption. Otherwise it was classed as a planned interruption.

845. Whilst our historical reliability performance compares favourably with our peers, Figure 108 shows the historical performance of Reported SAIDI has an increasing trend and comparison to the DPP2 target shows that Aurora exceeded the target during each year of the period.

846. In addition, Aurora also exceeded the limits during DPP1, indicating the historical limits have been low compared to network performance and there has been a long term increasing trend (declining performance) on the network.

Figure 108: Historical reported SAIDI performance

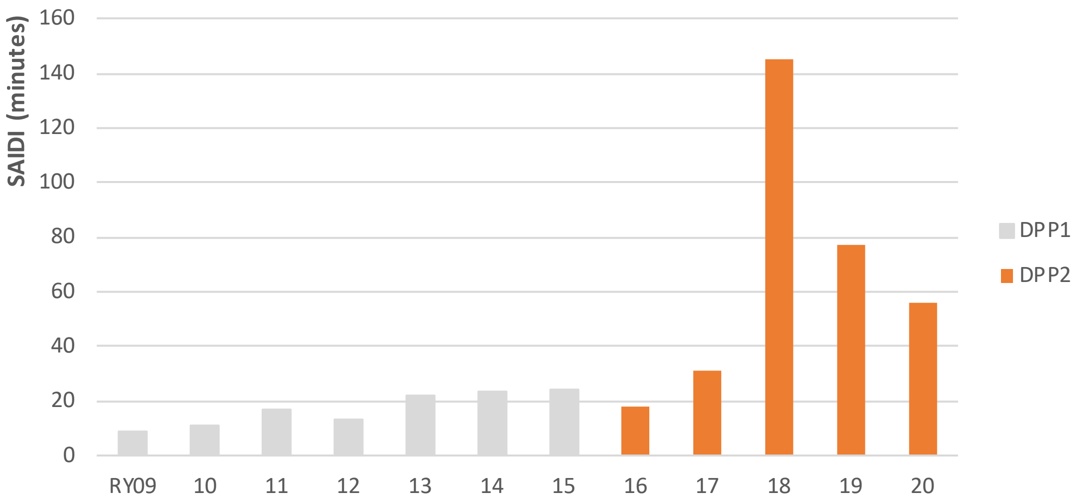


847. The performance is separated into the component parts of planned and unplanned SAIDI in Figure 109 and Figure 110. This shows that a significant driver of the total SAIDI in RY18 through to RY20 was caused by planned activities.

848. The planned activities in RY18 and RY19 are the result of Aurora's accelerated pole replacement program and other planned initiatives to improve the condition of the network and reduce safety risk.

849. The reduction in RY19 and RY20 shows that the type of asset renewals undertaken had a lower impact on planned outages. This outcome demonstrates the importance of analysis to understand the linkage between each asset renewal programme and the impact on planned outages.

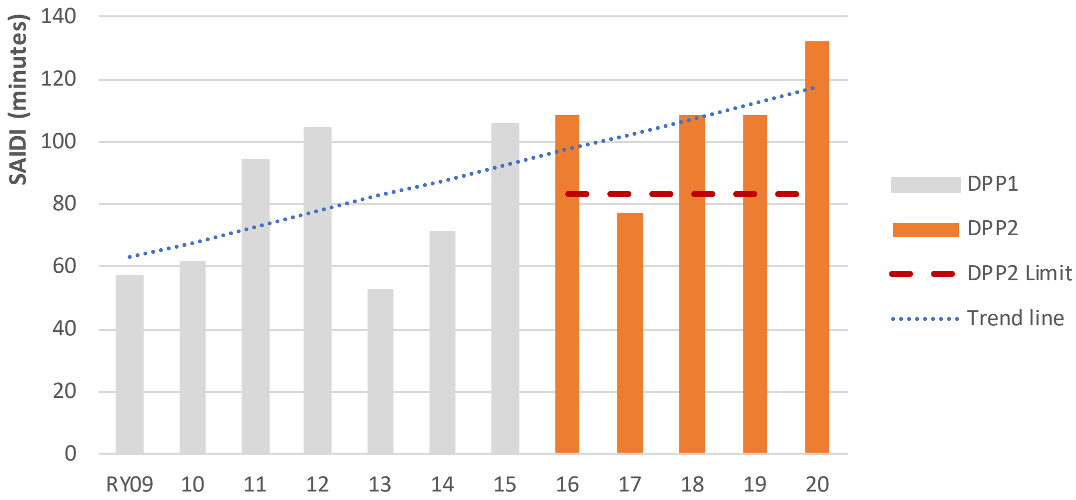
Figure 109: Historical normalised planned SAIDI



850. However, Figure 110 shows that even excluding planned outages, the performance would have exceeded the target in all years except for RY17. Normalised unplanned SAIDI has been

demonstrating an increasing trend since 2009. During DPP2, non-asset related outages (for example vegetation and animals) have contributed 77% of the outages.

Figure 110: Historical normalised unplanned SAIDI



L.2.2. SAIFI

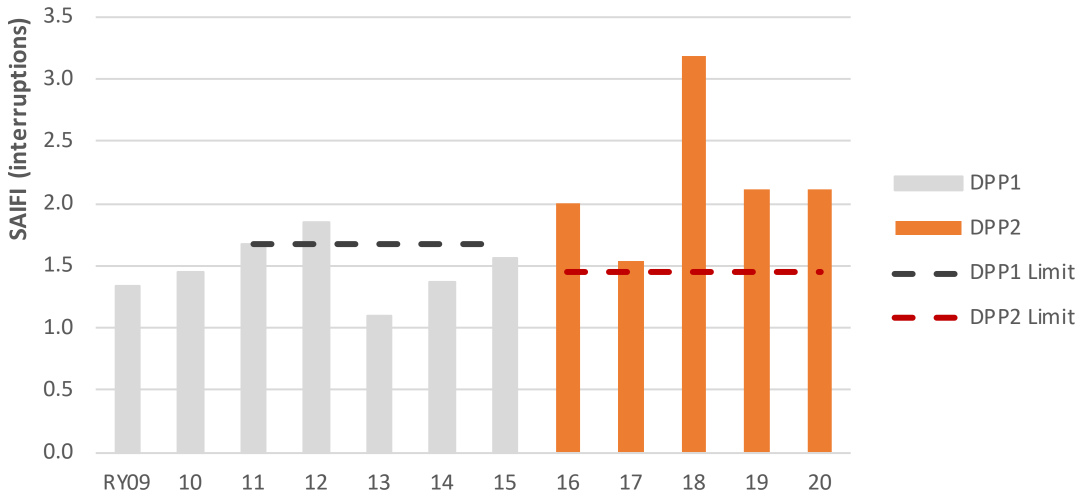
851. During DPP2, network performance was reported as the sum of normalised unplanned SAIFI plus normalised planned SAIFI. where:

- Normalised unplanned SAIFI was adjusted to replace SAIFI incurred during Major Event Days (MEDs) with the MED Boundary Value and to exclude other excludable events.
- Normalised planned SAIFI was adjusted to de-weight the SAIFI incurred by 50%
- An unplanned interruption is any interruption where there was less than 24 hours' notice, or no notice, provided to the public or all consumers affected by the interruption. Otherwise it was classed as a planned interruption.

852. Figure 111 shows the historical performance of Reported SAIFI compared to the DPP2 target. This demonstrates that Aurora exceeded the target during each year of the period.

853. In addition, Aurora also exceeded the limits twice during DPP1, indicating the historical limits have been low compared to network performance and there has been a long term increasing trend (declining performance) on the network.

Figure 111: Historical reported SAIFI performance

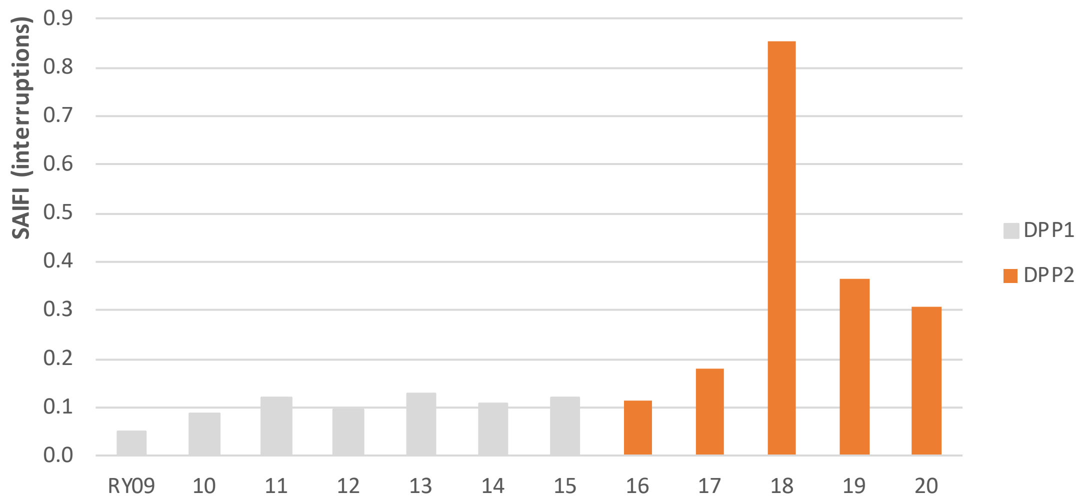


854. The performance is separated into the component parts of planned and unplanned SAIFI in Figure 112 and Figure 113. This shows that a significant driver of the total SAIFI was caused by planned activities.

855. These planned activities in RY18 and RY19 are the result of Aurora's accelerated pole replacement program and other planned initiatives to improve the condition of the network and reduce safety risk.

856. The reduction in RY19 and RY20 shows that the type of asset renewals undertaken had a lower impact on planned outages. This outcome demonstrates the importance of analysis to understand the linkage between each asset renewal programme and the impact on planned outages.

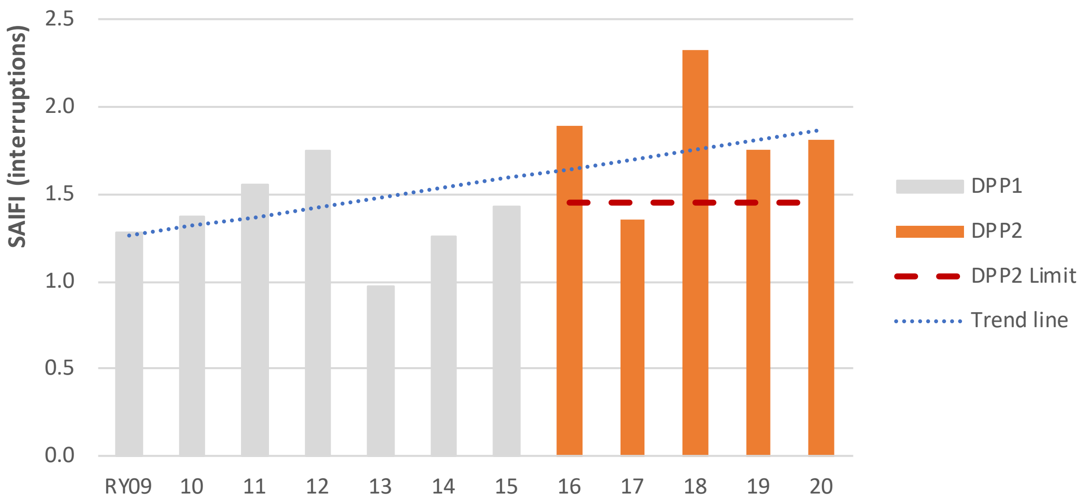
Figure 112: Historical normalised planned SAIFI



857. Figure 113 shows that even excluding planned outages, the performance would have exceeded the target in all years except for RY17. Normalised unplanned SAIFI has been demonstrating a

moderately increasing trend since 2009. During DPP2, non-asset related outages (for example vegetation and animals) have contributed 77% of the outages.

Figure 113: Historical normalised unplanned SAIFI



L.2.3. Outcome

858. The SAIDI and SAIFI charts presented in section L.2.1 and L.2.2 provide evidence of a sustained, long term increasing trend in unplanned outages and non-compliance with the reliability limits. We have undertaken investigations into network risk and reliability. In 2013, the condition of our assets was highlighted as a primary driver of the deterioration in reliability performance in a report by Strata Energy Consulting (Strata) for the Commission [45]. More recently, we engaged WSP to review the condition of our electricity networks, following public concerns regarding the safety of our assets. In its independent expert report, WSP highlighted reliability and safety issues arising from the following asset classes[46]:

- Protection systems;
- Support structures, including both poles and the pole top structures;
- Overhead conductors; and
- Distribution switchgear

859. WSP also identified a trend increase in the percentage of unplanned outages caused by defective equipment.

860. The combined impact of deteriorating asset health; changes in operational practice to better manage safety and fire risk[47]; and an increase in planned outages to support higher volumes of asset

45 Strata Energy Consulting, Report on the reliability performance of Aurora Energy Limited, Produced for The Commerce Commission, 24 June 2013

46 WSP, Independent Review of Electricity Networks, 21 November 2018, page 49.

47 These practices include inhibiting the use of auto reclosers and conducting full line patrols prior to re-energising lines during summer months, to manage fire risk.

renewals, has led to our reliability performance struggling to meet the Commission's compliance standards.

L.3. Consumer and Stakeholder Preference

861. Aurora undertook extensive community and stakeholder consultation to provide a key input for developing the capital and operational expenditure strategies and plans for the CPP proposal. The consultation occurred in stages throughout the development of the CPP proposal and included:

- telephone surveys of more than 1,000 residential and more than 100 business customers;
- engaging directly with local customers through six separate Customer Voice Panels in three locations across the network;
- convening a CPP Customer Advisory Panel, which brought together community organisations, consumer advocacy groups, local Councils and sector participants through a series of facilitated workshops.

862. The overwhelming results were that consumers generally accepted the current level of network reliability provided by Aurora and were primarily concerned about network safety, the cost of electricity and other non-network service metrics. Approximately 90% of residential and business customers regarded safety attributes as either 'essential' or 'very important', while a significant amount of feedback identified that affordability was a significant issue for many customers, with price increases being a greater concern than reliability at this time.

863. The feedback and information gathered through these engagement processes was reflected in a consultation document on our draft plans published in December 2019 . The consultation document also set out alternative scenarios which had a stronger focus on improving reliability and the resulting impact on electricity prices.

864. Customers and stakeholders confirmed that there is very limited appetite for additional investment above the level set out in our draft plan. In summary, customer feedback indicates that whilst reliability remains 'essential' or 'very important', affordability and safety considerations are currently more important.

865. The outcome of the consultation has been incorporated in the CPP forecast through the focus on network safety and recognising reliability improvement as a secondary benefit, not the primary driver. This is reflected in the forecast reliability performance which shows the decline in reliability will be arrested and a slight improvement will be achieved in the later part of the CPP period due to safety-focused asset renewal.

L.4. Alignment to Aurora Energy's Policies

866. Our mission is to deliver electricity to our communities when and where it is needed, safely, reliably and efficiently. Our Quality Standards proposal is governed by our policies which reflect our network obligations and customer preferences. Our suite of network management documentation starts with our Asset Management Policy which states:

- We expect safety, nothing less. We will never do anything that undermines this core commitment.
- We will use improved asset data and complete, accurate and timely information to ensure decisions deliver value while balancing cost, risk and performance. We will monitor the performance of the network to ensure that benefits are realised.
- We will build effective relationships with our customers and stakeholders and align our asset management decisions to our understanding of their balanced needs and values.
- We will be visible in providing an enduring network that meets our understanding of customers' long-term needs, to ensure that we are recognised for providing essential electricity services to support the future growth and wellbeing of our communities.

867. Customer consultations have shown that customers place a high degree of value on the safety of the network. Our acknowledgement of this is demonstrated by building a high-performance safety culture in order to safeguard the public and to ensure an injury-free workplace. Aurora wishes to prioritise expenditure accordingly in order to deliver safety improvements, causing zero harm to the general public and eliminating as far as is reasonably practicable safety risks to its own workforce.

868. Whilst another priority is the delivery of excellence in asset lifecycle management, which can be measured by delivering improved asset performance and reliability, Customers have expressed that they would prefer maintaining current levels of reliability if it meant that significant cost increases required for improvement could be avoided. Customer preference is that any cost increases should first and foremost result in safety improvements, and that any reliability improvements would be an additional benefit resulting from improvements in safety.

869. We have acknowledged our customers' preference in our Reliability Management Plan. The plan identifies the 'performance levers' we can use to manage network performance and customer experience. This plan, however, recognises the safety focus and constraints of the CPP expenditure program and that in the short-term, any reliability improvements will be achieved through safety-driven works and there will not be any reliability specific programs.

Our Quality Standard proposal therefore reflects our policies and what customers have told us are their 'balanced needs'. This means deferring reliability investment in the short-term to focus on safety while positioning the network to create reliability performance options that meet the long-term needs of our customers.

L.5. Recent Changes in the DPP3 Decision

870. A key purpose of forecasting our future reliability performance is to inform the reliability standards that we will propose for the CPP period. Our view is that these limits should be calculated in accordance with the Commission's definitions of planned and unplanned reliability performance, which have been amended in its recent DPP3 decision.

871. The Commission's DPP3 decision adopted the following design changes to the reliability standards:

- Separate standards for planned and unplanned SAIDI and SAIFI;

- Annual unplanned reliability standards for SAIDI and SAIFI;
- Unplanned reliability standard at 2.0 standard deviations greater than the historical average;
- Remove the two-out-of-three rule for planned and unplanned standards;
- Regulatory period length standard for planned SAIDI and SAIFI;
- Planned outage standard at three times the historical average;
- Introduce new measures for extreme events; and
- Apply new normalisation rules based on a 24-hour rolling window.

872. In addition, the Commission also modified the design of the incentive rates, including:

- Removing the revenue-linked quality incentive scheme for SAIFI;
- Adopting incentive rates, based on a VoLL of $25,000/MWh adjusted to reflect incentives provided by IRIS Retention Factor (23.5%) and Quality Standards (10%);
- Setting the SAIDI targets at the historical average of unplanned SAIDI and planned SAIDI over a 10-year, 2010-2019 period;
- Setting the SAIDI cap for the incentive scheme at the compliance limit;
- Setting the SAIDI collar for the incentive scheme at zero; and
- Adopting a total revenue at risk of 2%.

873. We support the Commission's latest approach to establishing the quality path, as set out in its DPP3 decision. However, as a CPP applicant, it is appropriate for us to undertake further analysis to assess whether the specific limits and targets in the DPP3 decision are reasonable for us, given our proposed expenditure plans, the condition of our network assets, and other factors affecting our future reliability performance. Our assessment has been informed by our reliability modelling, as described in section L.9. We set out our findings in the following sections.

L.6. PERFORMANCE INDICATORS SELECTION

874. Aurora is required by the Input Methodologies Clause D5 to describe the performance indicators proposed for the next CPP period. This must include SAIDI and SAIFI and should include consumer orientated indicators and indicators of asset performance, asset efficiency and effectiveness.

875. For network performance indicators, Aurora proposes the same metrics as set out by the Commission in the DPP3 determination, but proposes some alternative values. These are:

- Unplanned SAIDI with a linked incentive scheme
- Unplanned SAIFI
- Planned SAIDI with a linked incentive scheme
- Planned SAIFI
- Extreme event standard

876. These performance indicators align with Aurora's obligations and policies to provide appropriate levels of reliability at an efficient cost to consumers. The target and limit values are described in

section L.7 and have been set to reflect what is practically achievable given the current network configuration, condition and planned expenditure levels.

877. In addition, Aurora has set out a number of future non-network performance indicators that are not linked to any incentive scheme, but are aimed at ensuring good levels of customer service and efficient asset management and asset performance.

878. These additional performance indicators include metrics for:

- Safety first
- Reliability to defined levels
- Affordability through cost management
- Responsive to a changing landscape, and
- Sustainability by taking a long-term view

879. Additional information on these indicators is provided in chapter 4.6 of our Asset Management Plan and are not described in this document any further.

880. Through consultation, we sought feedback on what service measures customers valued. Customers told us that they expected some customer services were fundamental, but that affordability is a primary concern. From a range of possible customer service measures, those we included in our final proposal were either considered by customers to be essential to the service we provide or were highly valued by customers as priorities to add or improve. Accordingly, our final proposal includes provision of:

- **Outage communications:** continue to provide call centre and outage notification service with further enhancements to real-time updates for unplanned outages with cause and restoration times
- **New connections process:** continue improvements to the process for new connections and establish service level targets
- **Customer Charter credit scheme:** continue compensation scheme for unmet service levels and review complaints process and compensation policy.

L.7. Proposed Quality Standard Variation

881. In this section, we set out our proposed Quality Standards indicators, targets and limits for planned and unplanned reliability.

882. Our analysis has concluded that the Commission's DPP3 reliability standards for planned SAIDI and SAIFI are appropriate for the CPP period RY22 - RY24.

883. However, this is not the case for unplanned SAIDI and SAIFI. As stated in Clause 5 of Attachment A of the Information Disclosures, the targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. We have therefore developed an alternative forecast for unplanned SAIDI and SAIFI that better reflects the historical

network performance, the views and feedback from our consumers, and the objectives of our safety focused capital and operational programme of works for the CPP period.

884. These alternative unplanned reliability measures better achieve the Expenditure Objective by minimizing the cost impact on consumers while still ensuring a safe network that achieves the level of reliability identified as the consumer preference during our consultation process.

L.7.1. Quality Standards – Planned Interruptions

885. Aurora accepts the planned accumulated SAIDI and SAIFI limits set out by the Commission in Table 3.1.1 of the DPP3 determination for the five-year DPP period RY21 to RY25. However, we propose to adjust the limits on a pro-rata basis to reflect a three-year CPP period commencing in April 2021, as set out in Table 49 below.

Table 49: Proposed planned accumulated SAIDI and SAIFI limits

Proposed Planned Quality Standards	5-year (DPP3) RY21-RY25	Annualised[48]	3-year RY22-RY24
Planned SAIDI limit (minutes)	979.80	195.96	587.88
Planned SAIFI limit (interruptions)	5.5385	1.108	3.3231

L.7.2. Quality Standards – Unplanned Interruptions

886. As shown in section 0, unplanned SAIDI and SAIFI performance of the network has been deteriorating since RY09.

887. In section L.3, we described that extensive consultation found that consumer and stakeholder preference was to prioritise safety whilst minimising the cost impact to customers. Importantly, consumer and stakeholder sentiment was that the current level of network reliability was considered acceptable. We developed the capital and operational expenditure forecast for the CPP proposal to achieve these objectives.

888. Our proposed SAIDI and SAIFI quality standards for unplanned interruptions are set out in Table 50: Proposed unplanned SAIDI and SAIFI standards below. These values represent the reliability outcomes resulting from an efficient capital and operational expenditure programme that is primarily targeted at managing network safety. The same parameters are proposed for each year of the three-year CPP period from RY22 to RY24.

48 The annualised value is the same for the three- and five-year periods.

Table 50: Proposed unplanned SAIDI and SAIFI standards

Unplanned Interruption Quality Standard	SAIDI	SAIFI
Unplanned limit	146.29	2.5067
Unplanned boundary value	5.69	0.0737
Unplanned interruption target	113.34	1.9948
Forecast average	110.33	1.9195
Scaled standard deviation	16.48	0.2560

889. Figure 114 and Figure 115 below compare the proposed parameters with the historical unplanned SAIDI and SAIFI performance of the network and the Commissions DPP3 determination.

890. The dotted blue line labelled 'DPP3 Backcast' shows the historical performance reassessed using the revised DPP3 rules and the dotted red line labelled 'Annualised DPP3 Limit' is the limit set by the Commission in the DPP3 determination published in November 2018. This highlights that the Commission's Annualised DPP3 Limit is significantly lower than the recent historical data and therefore is not an appropriate service level target, as required by the Expenditure Objective.

891. The charts demonstrate that Aurora's proposed parameters are consistent with historical performance when compared on a like for like basis. In addition, the target and limit require Aurora to meet the objective of arresting the historical trend of deteriorating performance and to maintain current levels of reliability.

Figure 114: SAIDI forecast, targets and limits

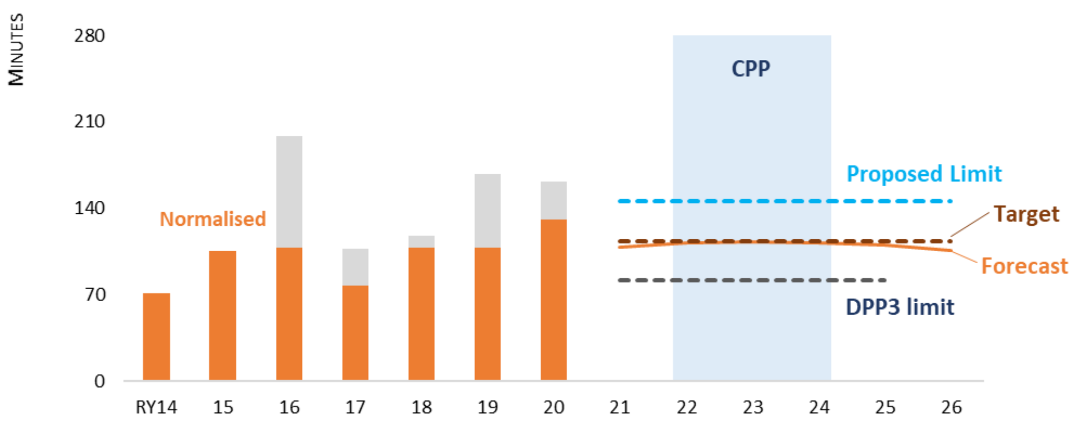
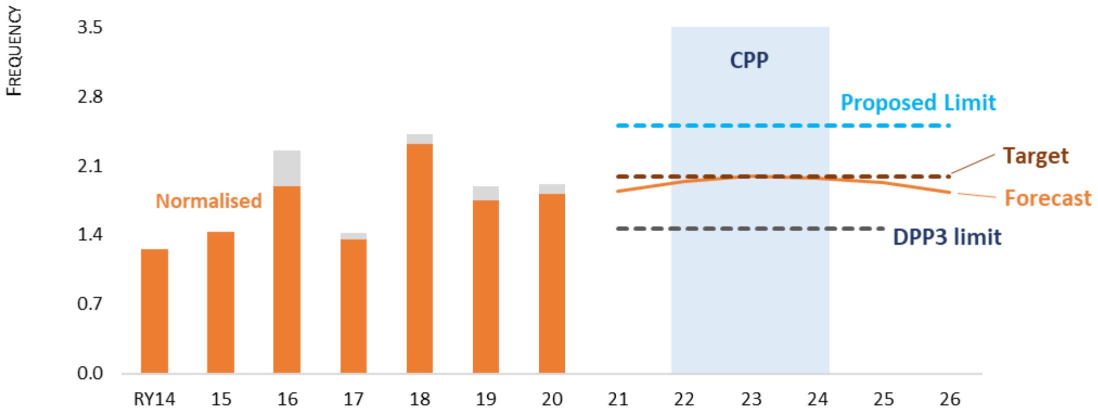


Figure 115: SAIFI forecast, targets and limits



L.7.3. Quality Standards – Extreme Events

892. Aurora accepts the SAIDI and customer-minutes extreme event limits set out by the Commission in Schedule 3.3 of the DPP3 determination.

L.8. Comparison to the DPP3 Determination

893. In November 2019, the Commission released the DPP3 determination that set out the reliability parameters for all EDBs which elect the Default Price Path for the period RY21 to RY25. An important constraint established by the Commission in determining the DPP3 parameters was to limit the maximum change from the DPP2 parameters .

894. As shown in section 0, Aurora's network performance has deteriorated during DPP2 and the proposed DPP3 targets are limited to values that are not reasonably achievable. The expected cost to achieve the Commissions DPP3 reliability performance does not represent an efficient level of expenditure appropriate to the expressed preferences of our consumers and the timeframe to achieve such a change in performance.

895. Table 51 and Table 52 compare the parameters proposed by Aurora to those calculated by the Commission in the DPP3 determination. They show that Aurora is proposing a significant increase in all parameters except for the boundary values for major event days.

896. The difference between the DPP3 values and the proposed values in this Quality Standard Variation is largely driven by the approach applied by the Commission. The Commission used a historical reference period to calculate the average performance and restricted the change from DPP2 to DPP3 to a maximum of 5%.

897. Aurora considers that the Commission's approach is appropriate for an EDB in a steady state business as usual situation. However, Aurora is in a dynamic state with a historical trend showing

deteriorating network performance and is submitting a CPP application to enable it to make significant improvements to network management.

898. Hence, we have developed a model that reflects our unique situation. The model uses detailed analysis of historical performance data and better reflects the current condition and performance of the network. It also accounts for the capital and operational plans proposed for the CPP period. This model is explained in L.9.

899. Our proposed target is calculated from our forecast performance and we have applied a scaled version of the DPP3 standard deviation calculation based on the ratio of the forecast target compared to the DPP3 target. This will allow for annual volatility in accordance with the Commission's approach in its DPP3 decision. As already noted, our proposed limits for both unplanned SAIDI and SAIFI are materially above the DPP3 limits.

900. We have retained the Boundary values for both unplanned SAIDI and unplanned SAIFI and the extreme event standard and value as set out by the Commission in the DPP3 determination.

Table 51: Proposed unplanned SAIDI parameters

Proposed Unplanned Parameters	Aurora CPP	DPP3	Difference
Proposed boundary value	5.69	5.69	0
Scaled standard deviation	16.48	9.22	7.26
Proposed target	113.34	63.44	49.90
Proposed unplanned limit	146.29	81.89	64.40

Table 52: Proposed unplanned SAIFI parameters

Proposed Unplanned Parameters	Aurora CPP	DPP3	Difference
Proposed boundary value	0.0737	0.0737	0
Scaled standard deviation	0.2560	0.1500	0.0760
Proposed target	1.9948	1.169	0.8258
Proposed unplanned limit	2.5067	1.4687	1.0380

Table 53: Proposed extreme event parameter

Proposed Unplanned Parameters	Aurora CPP	DPP3	Difference
Extreme event standard (SAIDI)	120	120	0
Extreme event standard (customer minutes)	6,000,000	6,000,000	0

L.9. Forecasting Performance

901. Aurora developed a forecast for unplanned network SAIDI and SAIFI that provides target and limit parameters that are consistent with historical and forecast performance. The historical performance with the DPP3 limit, proposed limit, proposed target and forecast is shown above in Figure 114 and Figure 115 for SAIDI and SAIFI, respectively. A summary of the key parameters is shown in section L.7.

902. The table and charts demonstrate that the proposed quality price path parameters proposed by Aurora are an increase compared to the DPP3 values, but are reflective of recent historical network performance. While the proposed limit is set slightly above the historical normalised performance, the target it consistent with the historical normalised performance providing strong incentive to arrest the increasing trends and stabilise performance during the CPP period.

903. In the figures below the red dotted line labelled as DPP3 denotes the back-casting of the historical performance using the methods described in this document. This demonstrates that the methodology is producing results that are of a similar magnitude and trend – including annual volatility – as observed in the historical performance.

904. Aurora developed the forecast using four modelling approaches based on the type of fault (asset or non-asset) and the data available. An overview of the approaches taken are set out in Table 54 below and described in further detail in the following sections.

Table 54: Forecast methodologies applied

Category	SAIDI	SAIFI
Cross-arms	Linear regression	3-year average
Distribution Cables	Linear regression	3-year average
Distribution Conductors	Linear regression	Multivariate regression
Distribution Transformers	Linear regression	Multivariate regression
Ground Mounted Switchgear	Linear regression	Multivariate regression
Other	Linear regression	3-year average
Pole Mounted Fuses	Linear regression	Multivariate regression
Pole Mounted Switches	Linear regression	Multivariate regression
Poles	Linear regression	Multivariate regression
Protection	Linear regression	3-year average
Sub transmission Conductors	Linear regression	3-year average
Non-Asset	Linear regression	3-year average
Vegetation	Linear regression	Trend to target

905. The following sections describe the approaches taken to develop the forecast, list the models used and key assumptions and inputs.

L.9.1. Multivariate Regression

906. As set out in Table 54, Aurora applied a multivariate regression approach to forecast SAIFI. A Generalised Linear Model (GLM), which is a type of linear regression model that is suitable for non-continuous data sets such as outage data, was applied to historical data from 2014 to 2020 to determine the relationship between asset condition and SAIFI.

907. 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.

908. The asset data was normalised to have a mean of zero and a standard deviation of one and outliers in the outage data, identified as outages with SAIFI greater than 1.5 standard deviations above the mean, were excluded from the modelled data set. This was done to facilitate the GLM and avoid skewing the output due to large outages in a small data sample.

909. SAIFI is calculated as the sum of all consumers interrupted divided by the average annual consumers supplied by the network. Since the total number of consumers changes annually, to remove another variable, the target variable was chosen to be customer numbers impacted annually.

910. The GLM therefore related five inputs to the number of customers impacted. These five inputs were:

- Assets with AHI of 1. These assets are in the worst condition and therefore have the greatest probability of failure and influence on network performance.
- Assets with AHI of 2. These assets are in very poor condition and therefore have a very high probability of failure and influence on network performance
- The annual change in volumes of assets with an AHI of 3. The volume of assets in AHI3 are generally significantly higher than the volume of assets in AHI 1 and 2. Testing found that including only the annual change of volumes in AHI3 provided the best relationship. Assets with AHI's of 4 and 5 are in good condition, have low probability of failure and therefore negligible impact on network performance.
- A weighting factor to increase the importance placed on the more recent years as they are more reflective of the current state of the network and operational practices.
- A factor that reflects the proportion of outages that were excluded during the normalisation and outlier removal process.

911. The coefficients calculated by the GLM were then applied to forecast the number of customers impacted each year which was divided by the forecast network consumer numbers to calculate the SAIFI performance for 2021 to 2026.

L.9.2. Three-Year Average

912. We identified six categories for which the multivariate approach was not able to be applied. There were five asset categories where sufficient asset health data was not available and the non-asset category, which is related to external impacts and not to the health of an asset.

913. We used a simple three-year average based on the most recent historical data from 2018 to 2020. Historical performance is a guide to future performance of the network and the averaging is applied to smooth the volatility. The period selected is considered reflective of the current state of the network, representative of the future state given the forecast capital and operational plans, and is therefore appropriate for this short-term forecast.

L.9.3. Trend-to-Target

914. The vegetation category covers outages caused by vegetation clashes with network assets. The management of vegetation is governed by a set of regulations which set out the rights and obligations Aurora must adhere to, including where the responsibility lies with other organisations, i.e., local council. These outages are not related to any specific asset's condition. Recent years demonstrate an increasing trend, but application of the trend results in an unrealistic forecast.

915. However, Aurora has a specific Vegetation Strategy which sets out the objective and KPIs in terms of SAIDI and SAIFI contribution. Therefore, Aurora has forecast a glide path to achieving their strategic objectives. The starting point in RY21 was taken as the average of the preceding three years with a linear reduction to achieving the targets in RY24.

L.9.4. Linear Regression

916. SAIDI was calculated for all categories based on a linear regression against SAIFI using historical data from 2014 to 2020. The coefficients of the regression were applied to the forecast SAIFI to calculate the forecast SAIDI.

917. SAIDI and SAFI have the relationship:

equation (1) SAIDI = SAIFI x CMOS

918. SAIFI was calculated using the methods described in the sections above which incorporates the relationship to AHI, and changes to AHI over time. However, SAIDI is dependent on additional parameters which are not able to be extracted from the outage data with a sample size large enough to be used in a statistical model. In particular, the duration of the outage and the staging of the restoration which both affect the CMOS incurred during an outage vary significantly based on local network conditions and topology.

919. Using the regression approach enables the variables affecting CMOS to be implicitly estimated in the regression through the relationship to SAIFI.

920. Since the volume of asset replacements is forecast to be as small percentage of the network, the recent historical relationship between SAIDI and SAIFI is appropriate for forecasting over the short term.

L.9.5. Setting the Limit and Target

921. The forecast SAIDI and SAIFI performance were then the sum of the SAIDI and SAIFI across all modelled categories multiplied by a scaling factor to convert from Raw to Normalised (allowing for MEDs and other excludable events).

922. Aurora set the proposed target based on the highest forecast SAIDI or SAIDI across the forecast period.

923. The proposed Limit was calculated as the Target plus two standard deviations. The standard deviation was the DPP3 standard deviation, scaled to account for the higher Target.

L.10. Proposed Financial Incentives

924. This section sets out the methodology used to calculate the Quality Incentive Parameters, the key inputs used and why this is appropriate for Aurora.

L.10.1. Quality Incentive Parameters

925. To calculate the incentive rates for planned and unplanned SAIDI, Aurora applied the methodology set out by the Commission in Schedule 4 of the DPP3 Determination[49].

926. The Commission amended the incentive arrangements for DPP3 so that revenue-linked incentives only apply to planned SAIDI and unplanned SAIDI. The Commission also set the planned and unplanned SAIDI ‘collars’ to zero. This approach means that there is constant financial incentives for reliability improvement apply, no matter what level of improvement has already been achieved.

927. While we agree with the Commissions methodology, we are proposing a number of different input variables, namely:

- Unplanned SAIDI target and limit values as described in Table 51;
- the Value of Lost Load (VoLL) as described in section L.10.2; and
- Planned SAIDI parameters as described in section L.10.3.

928. Our proposed incentive rates, which are calculated in an accompanying spreadsheet, better reflect our particular circumstances, our customers’ preferences and our customers’ willingness to pay for reliability.

929. Our proposed quality incentive parameters are set out in Table 55.

[49] Commerce Commission. (2019). Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision. Schedule 4.

Table 55: Quality incentive parameters

Quality Incentive Parameters	Value	Unit
Maximum revenue at risk	2%	of MAR
IRIS Retention factor	23.5%	factor
Quality Incentive Adjustment	90%	factor
Planned incentive rate	$7,140	per minute
Unplanned incentive rate	$14,279	per minute
Planned SAIDI cap	195.96	minutes
Planned SAIDI revenue neutral point	161.63	minutes
Planned SAIDI collar	0.00	minutes
Unplanned SAIDI cap	146.29	minutes
Unplanned SAIDI revenue neutral point	110.33	minutes
Unplanned SAIDI collar	0	minutes

930. We have tested the implied revenue at risk for both the planned and unplanned reliability incentive against the ranges determined for DPP3[50]. The implied revenue at risk lies within the range of DPP3 outcomes for peer EDBs, and therefore we consider that our approach preserves consistency with the DPP quality incentive framework.

Table 56: Implied Revenue at risk - comparison with DPP3

	Maximum Penalty			Maximum Reward		
	Unplanned	Planned	Total	Unplanned	Planned	Total
Aurora Energy CPP	**0.51%**	**0.82%**	**1.33%**	**1.58%**	**0.59%**	**2.00%**[51]
DPP3 Maximum	1.09%	2.28%	2.00%	3.13%	1.14%	2.00%
DPP3 Minimum	0.21%	0.11%	0.32%	0.24%	0.06%	0.39%

L.10.2. Determination of VoLL

931. The most recent and applicable review of the Value of Lost Load (VoLL) for customers was undertaken by Transpower and published in November 2018 [52].

932. The analysis was undertaken using a survey methodology. The study investigated the VoLL across New Zealand by point of supply on the Transpower network and found that the VoLL generally varied

50 Commerce Commission. (2019). Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision. Table M5, p444.

51 The actual total is 2.75%; however, it is capped at 2.00% of MAR.

52 Transpower. (2019). Value of lost load study.

between $17,000/MWh and $40,000/MWh depending on the composition of customer types at the supply point.

933. The results centred around $25,000/MWh which aligns to the VoLL proposed by the Commission and used in the DPP3 determination. While that is appropriate for a broad study across all of New Zealand, Aurora was able to extract the actual results for each point of supply to their network and use that as a more accurate VoLL for their consumers, as shown in Table 2.

934. Based on the information provided, the VoLL at each connection point was escalated to RY20 dollars and the average was calculated as representative of the network. We consider that this VoLL, established for the Aurora network, is better evidenced and defendable than the $25,000 per MWh set by the Commission for the DPP3 incentive framework.

935. Therefore, we have adopted the VoLL estimate of $27,136/MWh as derived from the Transpower VoLL study rather than the estimate adopted by the Commission for the DPP3. This results in an incentive rate that is more objectively derived, and which better reflects our particular circumstances and our customers' preferences than that stated in the DPP3 decision.

Table 57: Value of Lost Load by network connection point

Area	Transpower Feeder	2018+	Average VoLL (2020)[53]
Dunedin	HWB033	$21,100	$21,759
Dunedin	HWB033	$25,300	$26,090
Central	CML033	$27,200	$28,050
Central	CYD033	$29,300	$30,215
Central	FKN033	$26,800	$27,637
Central	FKN033	$30,000	$30,937
Central	SDN033	$24,500	$25,265
Total			**$27,136**

L.10.3. Adjustments Applied for a Three-Year CPP Period

936. Aurora applied the same calculation methodology as the Commission did in the DPP3 determination, however, we adjusted some input parameters to reflect the three year CPP period. The adjustments were:

- Unplanned SAIDI target and limit values were calculated by Aurora using the Unplanned Reliability Forecast Model. This is described in detail in section L.9.
- The Planned SAIDI limit was calculated on a pro-rata basis from the five-year limit. Due to the pro-rata calculation, the annualised value is the same in both cases.

[53] The VoLL was escalated based on rates of 1.5% in RY19 and 1.6% in RY20

- The Planned Assessed SAIDI was calculated in Aurora's Planned Reliability Forecast Model. The value was calculated as the average normalised SAIDI across the three-year CPP period. The normalised value included the reductions in SAIDI due to improved notification practices.
- The Planned SAIFI limit was calculated on a pro-rata basis from the five-year limit. Due to the pro-rata calculation, the annualised value is the same in both cases.
- The Maximum Allowable Revenue was calculated as the average of the forecast revenue across the three year CPP period of RY22 to RY24.
- The average annual energy distributed (used in the calculation to convert dollars per MWh to dollars per minute) was calculated based on the average of the three years of RY17 to RY19.

937. All other calculations and inputs were applied as per the Commission's methodology.

L.11. Demonstrating the Expenditure Objective

938. This Quality Standard Proposal demonstrates that the forecast capital and operational expenditure programme, and resulting forecast for network reliability, meets the requirements of the expenditure objective.

939. As described in this proposal, the appropriate service standards with respect to network performance are SAIDI and SAIFI, and the appropriate levels of service have been identified through extensive customer consultation as maintaining current network performance.

940. The consultation identified that customers are most concerned about network safety and the price of electricity, and are generally accepting of the current levels of reliability being provided. As a result, Aurora has developed a programme of works that is focused on improving safety, but also recognises the consequential reliability benefits that are expected to be obtained.

941. Aurora Energy's application and supporting materials demonstrate that the proposed suite of capital and operational actions are required to provide electricity distribution services to the forecast number of network consumers and meet the expected level of demand.

942. The capital and operational expenditure forecasts have been demonstrated to be prudent and efficient as they are built upon: identification of regulatory obligations; appropriate analysis to identify assets in need of remedial actions to ensure compliance with the obligations; efficient unit rates as inputs to project cost development; and, economic justification for those actions to ensure the most efficient solution is selected.

943. The SAIDI and SAIFI targets and limits are consistent with historical performance during DPP2 but also provide incentive to arrest the historical deteriorating reliability performance. The forecast reliability targets and limits also reflect consumer preference to ensure network safety and maintain reliability to minimise any price impacts.

944. The financial incentives calculated are based on the best information available that is most specific to customers on Aurora's network and are consistent with the incentive rates applied to other EDBs in the Commission's DPP3 determination.

945. Together, this proposal demonstrates that the proposed Quality Path Variation meets the requirements of part (a) of the expenditure objective, as the appropriate level of network service has been identified, and Aurora has developed an expenditure forecast that will allow this to be achieved at an efficient cost to maintain compliance with regulatory obligations as required by part (b).

946. In linking to expenditure, due consideration must be given to the fact that our CPP proposal is focussed on improving the health of our assets and reducing risk to the public and our contractors working on the network. Our customers have said that they accept current levels of service,[54] and we are not proposing investments directly targeted at reliability improvement – we expect that to be a focus of our second CPP proposal, subject to customer support. We acknowledge that our investment will have an impact on reliability, to the extent that our reliability performance should stabilise, with modelling supporting that view.

[54] op. cit.

Appendix M. Delivering our CPP

947. Deliverability is a significant aspect of our CPP programme. Since 2017, we have enhanced our access to contracting resources, as we started to execute our works programme. From 1 April 2019, we implemented new field services agreement with Unison Contracting, Connetics and Delta. Those arrangements assure access to the skilled resources required to deliver our CPP programme, while providing a framework for improved service delivery and efficiency. This appendix provides and overview of our CPP delivery arrangements.

M.1. Field Services Agreements

948. Under our historical contracting arrangements, Aurora Energy contracted the provision of asset management, network operations and maintenance services. The contractor's obligations included:

- the preparation of network plans; and
- delivering an annually specified network performance and customer service.

949. With the benefit of hindsight, these arrangements failed to provide a sufficiently clear distinction between the roles of service provider and client, and instead created a blurring of responsibilities. In particular, this operating model:

- failed to provide the ordinary commercial tensions that should apply in a client-service provider relationship;
- provided limited scope to test the contractor's performance through competitive tendering and benchmarking unit costs;
- created weak incentives on the contractor to drive efficiency improvements over time; and
- provided insufficient focus on customer outcomes and KPIs.

950. These deficiencies in our operating model were first highlighted by Strata Energy Consulting in June 2013 and subsequently reflected in Deloitte's recommendation for organisational separation from Delta. As part of the organisational change, we recognised that Delta would not have the capacity to meet the significant projected increase in the level of network investment, particularly in the early years of the 2017-2027 Asset Management Plan. As a consequence, we sought new service providers through an Expression of Interest (EOI) tender process.

951. Our EOI document explained that:

- Aurora Energy would continue its established contractual relationship with Delta for core fault response, vegetation management, pole inspections, and value added services (including cable locations, stand-over services and high-load escorts).
- To complement the contract with Delta, Aurora Energy sought additional service provider/s to provide extra capability and capacity to deliver the planned increase in expenditure as outlined in the Asset Management Plan 2017-2027.

952. Prospective service providers were encouraged to review our draft 2018 AMP before lodging their response to the EOI. The detailed presentations and negotiations that were undertaken as part of the shortlisting and selection process naturally focused on the service provider's ability to deliver the work programme in an efficient and timely manner, as emphasized in the EOI registration of Interest:

> "Respondents shall demonstrate that they can attract, recruit, develop and retain sufficient skilled and qualified personnel to effectively deliver the Services without undermining the existing capacity of local resource available to Aurora Energy in the local market. Aurora Energy will highly value responses to this ROI from Respondents who can clearly demonstrate they can introduce new resource that complements the capacity and capability offered by Delta."[55]

953. Following extensive engagement with the short-listed parties, the successful new service providers were Unison in the Dunedin region and Connetics in the Central region. As already noted, Delta was the second appointed contractor in each of these regions. Each of our service providers is now subject to the provisions of the FSA, which includes numerous provisions that focus on promoting deliverability, as summarised in the table below.

Table 58: How FSA provisions support deliverability

Provisions	How does this provision promote deliverability?
Objectives	The FSA sets out a number of objectives, including to: ensure that the services are provided in a timely, efficient and cost-effective manner; promote open communication and problem solving; and continuously explore opportunities to improve the delivery of the services.
Annual Committed Expenditure (ACE)	The ACE specifies the value of work that Aurora Energy commits to provide to each service provider, which enables the service provider to undertake the necessary investment in plant, equipment and people. ACE levels are set below minimum forecast work volumes, achieving an efficient level of base work for contractors without the risk of over commitment by Aurora Energy.
Annual plan	The FSA requires Aurora Energy to issue an annual plan to each service provider at least 4 months before 1 April each year. The annual plan must provide a reasonable forecast of the ACE work. Aurora Energy is able to review the service provider's progress quarterly, and reschedule, delay, vary or cancel upcoming purchase orders that have not yet been started, if Aurora Energy has concerns regarding the service provider's ability to complete the work.

55 Aurora Energy. (2017). Registration of Interest, Provision of Electricity Distribution Network Field Services. 20 December 2017, page 14.

Provisions	How does this provision promote deliverability?
Competitive tendering	The FSA requires the service provider to make itself available to perform tendered works awarded to the service provider in its region. The service provider is also required to submit conforming bids for a proportion of tendered works in its region, in accordance with the relevant KPIs.
Customer Initiated Works (CIW)	The FSA requires each service provider to actively pursue CIW, which ensures that our customers have reasonable access to service providers and provides confidence that service providers are committed to delivering CIW.
Mobilisation Plan and resources	The service provider must prepare and submit to Aurora Energy a detailed mobilisation plan for the provision of the services. It must also undertake to provide a sufficient number of appropriately skilled, qualified and experienced personnel to ensure that the service can be provided in accordance with the FSA. In addition, it must provide the equipment, materials and plant necessary to carry out the work.
Fair price	The FSA contains provisions that give effect to the concept of a 'Fair Price', which ensures that Aurora Energy obtains a competitive price for the services it procures. The FSA includes a price review mechanism, which means that where the parties disagree as to whether a proposed price is a fair price or not, a review may be undertaken, and then escalated or arbitrated, as required.
KPIs and operational standards	These provisions ensure that services are delivered to an appropriate quality, consistent with good industry practice, including health and safety.

954. As already noted, our works programme will be delivered through a combination of FSA service providers, competitive tendering and panel arrangements. We will explain shortly our assessment of the potential deliverability gaps and the steps we are taking to manage these risks. In relation to the resources provided through the FSA, however, it is evident from the information set out above that:

- The appointed service providers had a good understanding of the scope of our work programme as detailed in the 2018 AMP and are committing resources to our region;
- The FSA contains provisions that support deliverability through a combination of commercial incentives and contractual requirements; and
- The FSA provides a reasonable degree of flexibility in how work is allocated between service providers and other approved contractors, in response to emerging deliverability or performance issues.

M.2. Project Management and Works Delivery

955. The contractual arrangements described in the previous section must be supported by effective project management and works delivery arrangements if the work programme is to be delivered on time and to budget.

956. To drive improvements in this area, we have established a Planning and Work Delivery design team to review the end-to-end work pipeline; specify and embed a new workflow, and develop supporting processes and a new project management methodology. This is a small fixed term project team for a 12 month period, which will ensure that we have the right processes in place to support prudent and efficient project delivery.

957. A key development to date is the installation of an Enterprise Portfolio and Project Management software tool called Sentient, which allows us to track projects and programmes through their lifecycle. Staff training has also been undertaken, upskilling and training 32 employees in Prince2 programme and project methodologies across the business. This training has significantly enhanced our governance and project management capabilities.

958. Over the next 12 to 18 months, we will continue to refine our systems and processes to make our internal and external delivery functions more efficient and streamlined. These initiatives will provide increased visibility of projects and programmes through all of their stage gates; clearer reporting of progress and units completed; and enhanced budget control management.

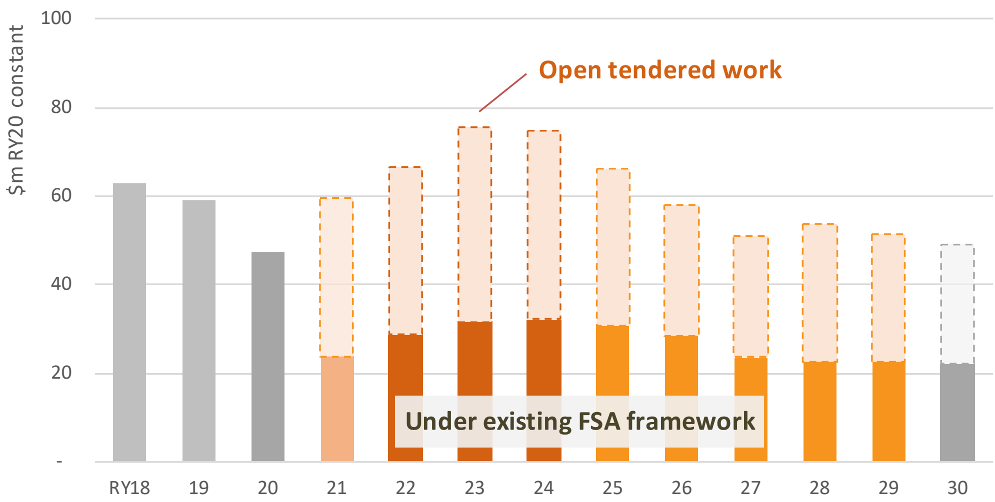
959. It is important to note that whilst it will take time to implement the necessary changes to our systems and processes, this work has already commenced. We expect further significant improvements to have been made prior to the start of the CPP period, which will provide additional assurance that the work programme will be supported by robust planning and works delivery processes.

M.3. Delivery Assessment and Risk Mitigation Measures

960. Our deliverability assessment has examined the growth in our proposed expenditure and work volumes in aggregate and across each asset category.

961. Figure 116, below, shows our forecast network capital expenditure alongside our recent historical spend. It also shows the proportion of capital expenditure undertaken through the FSA and competitive tender.

Figure 116: Historical and projected total network Capex



962. A simple 'headline' comparison between our historical and forecast network capital expenditure does not provide a robust deliverability indication because:

- RY18 and RY19 were predominantly focused on the delivery of the Fast Track Pole Programme, which is not representative of our forward-looking work programme;
- RY20 has been an establishment year for our new service providers as they build their resources and staff in our regions, and this has led to relatively lower levels of capital delivery;
- Total capital expenditure may be affected by a relatively small number of large value projects that may not raise resourcing issues; and
- Deliverability should be assessed at a more granular level because the constraints are likely to arise in relation to particular types of labour and materials.

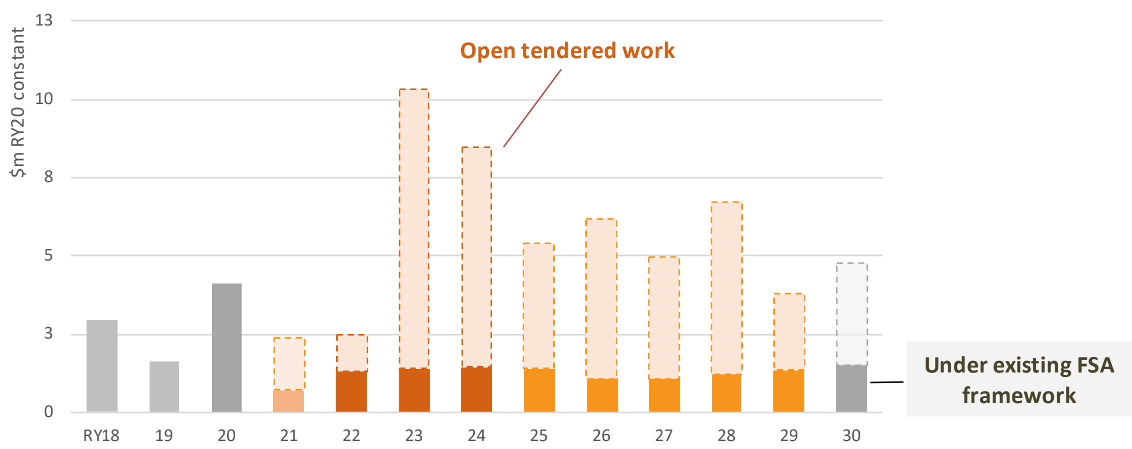
963. The figure above highlights the balance of expenditure between the committed works under the FSA and the expenditure that will be subject to open tender. The open tendered work principally relates to larger projects, such as zone substation rebuild projects, major renewal or growth projects that are typically high value projects. In contrast, the committed spend under the FSA contracts relates to high volume, repetitive work that is more routine in nature. It is expected that our FSA service providers will have sufficient capacity to bid for open tendered works, whilst additional, approved contractors will also be attracted to these projects.

964. Our more granular assessment of the work programme has identified the following fleet categories as raising potential deliverability issues:

- Overhead support structures;
- Zone substations;
- Cables; and
- Other distribution and low voltage (LV) work.

To illustrate the analysis for cables, the Figure 117, below, shows the historical and forecast expenditure split between FSA service providers and tendered work.

Figure 117: Cables historical and forecast expenditure



965. The cables work category includes major growth and renewals expenditure on subtransmission cables, which are expected to be competitively tendered. Over the forecast period, the larger renewal projects are expected to dominate the volumetric renewals of distribution and LV cables, which are expected to be undertaken through the FSAs.

966. Our further analysis has identified potential resource constraints in relation to specific categories of labour. In particular, cable jointers, civil contractors and design consultants are difficult to source. In relation to the design resources, we have therefore established a design consultancy panel to undertake this element of the work and avoid bottlenecks. We are also working with our service providers and approved contractors to take steps to ensure sufficient availability of technical and civil subcontractor resources.

967. For the purposes of this main proposal, it is useful to draw out the following high level observations from our deliverability analysis (rather than presenting the detail for each fleet category):

- Access to technical substation and protection contracting resources. Our field services contractors have a finite pool of specialised technical resources. Whilst there are other service providers available to provide resources for substation and protection work, we must compete with other electricity networks and generators for these resources.
- Civil works. The number of civil contracting resources inside our region is limited. This limited resource pool is exacerbated by challenging environmental conditions. We have had recent success with civil contractors from outside our region, providing confidence that solutions can be found.
- Supplier Panel agreements. Supplier panels provide an efficient method for procuring major assets, such as power transformers, and selecting specialist services, such as design consultants for substations. This procurement approach enables us to identify and actively manage any resourcing issues without impacting project timeframes.

968. Our overall assessment is that the work programme can be delivered on time, without exposing us and our customers to premium prices. Whilst we are confident that the work programme can be delivered, we have identified a number of risks that need to be actively managed. These risks are summarised in the table below, along with the actions that are currently underway to ensure that our work programme can be delivered on time and to budget.

Table 59: Delivery risks and mitigation measures

Delivery risks	How will we manage this risk?
Inadequate service provider capacity	If our FSA service providers are unexpectedly resource constrained, we can seek additional support from Electronet, BroadSpectrum and other regional service providers.
Emerging risk to planned overhead conductor replacement volume	In these circumstances, we would undertake a reappraisal of FSA service provider resources availability and take remedial action as required.

Delivery risks	How will we manage this risk?
Inadequate resources for zone substation design	We are currently establishing a Design Consultancy services panel, which will enable us to manage this risk.
Inadequate resources to construct zone substations	Strengthen our relationships with Electronet, Electrix and BroadSpectrum to bridge any identified resource gaps.
Substation and Secondary systems design and reviews	Undertake assessment of resource requirements over the CPP period and take remedial action as required.
Secondary systems construction volume	Confirm available resources with approved contractors alongside development of a resourcing and procurement strategy.
Failure to procure materials with long lead times	Power Transformer supplier agreement is already in place for the CPP Period. 11kV Switchboard supplier agreements are currently in the procurement phase.
Design resources and/or civil works inadequate for cable replacement programmes	Design consultancy panel will address the design component of these projects. We will work with approved contractors to confirm the availability of sufficient technical resources and civil subcontractor resources.

M.4. Current Actions to Manage Deliverability Risks

969. As explained in the previous sections, we recognise the importance of identifying and managing deliverability risks so that action is taken ahead of time to ensure that our work programme can be delivered as planned, without incurring a price premium to attract additional resources. Significant work has already been undertaken to establish new contractual arrangements with our service providers, supported by competitive tendering. These arrangements provide confidence that our work programme can be delivered. Our analysis of work volumes has highlighted those areas where further management is required to ensure that sufficient resources are available.

970. A number of specific initiatives are currently being actioned to ensure that the identified deliverability risks are reduced as far as practicable, including:

- Obtaining resource capability/availability statements from our service providers for the CPP period in relation to the work categories that raise potential resource challenges, being overhead structures; zone substations; cables and other distribution and LV work;
- Seeking guarantees from our service providers that sufficient resources are available to undertake targeted campaigns of work, including protection upgrades and cast iron pothead, ring main unit and crossarm replacements;
- Establishing panel agreements for supply of power transformers and 11 kV switchboards to secure the required resources; and

- Signing design panel consultancy agreements for substations, sub transmission and distribution works, to alleviate potential resource constraints.

971. Our expectation is that ongoing engagement with our service providers and approved contractors will be required during the CPP period to actively manage the deliverability risks described in the previous section, along with any additional emerging issues.

972. It is also worth noting that deliverability considerations led us to reject alternative options in our consultation document that included additional investment on regional resilience, future technologies and visual amenity. As such, deliverability has been a key consideration throughout the development of our CPP proposal.

973. We are confident that the CPP proposal can be delivered prudently and efficiently, given the resourcing approach that has been developed, which includes significant commitments made by our FSA service providers and the availability of approved contractors. These external resources will be supported by an enhanced internal capability in relation to programme management and governance. In addition, our risk analysis shows that there are sufficient additional resources and mitigation measures identified to ensure that our work programme can be delivered successfully. Actions are already underway to ensure that risks are managed ahead of time before they impact the deliverability and efficiency of our work programme.

974. Looking forward, we expect our contracting arrangements for field services to continue to evolve. As we and our service providers gain experience with the new arrangements, we expect to drive improvements over time, for example, by introducing unit rates for Routine Services; benchmarking cost performance; and improving working practices by comparing contractor performance.

M.5. Funding our CPP

975. We have secured funding throughout the CPP period from Dunedin City Treasury Limited, as set out in the letter of comfort provided in Appendix W.

Box 46: Deliverability justification

We have significantly enhanced our potential capacity to deliver an increased work programme by implementing a major reform of our contracting model. As a result, we have three principal field service providers, supported by approved contractors, competitive tendering and panel arrangements.

Our analysis of the available resources and our planned work programme shows that we have sufficient flexibility across our external service providers, supported by upskilled internal staff, to ensure that our CPP work programme can be delivered successfully. Where resource constraints have been identified, we are working with our service providers and approved contractors to bridge the gaps.

Appendix N. IM Schedule B – Cost Allocation Information

976. This appendix includes the following tables

- Table 1: Allocation of asset values
- Table 3: Allocation of operating costs
- Table 5: Rationale for selecting proxy allocator

For year ended: 31/03/19

Table 1: Allocation of asset values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	15,822
Not directly attributable	–
Total attributable to regulated service	15,822
Subtransmission cables	
Directly attributable	15,438
Not directly attributable	–
Total attributable to regulated service	15,438
Zone substations	
Directly attributable	82,446
Not directly attributable	–
Total attributable to regulated service	82,446
Distribution and LV lines	
Directly attributable	111,375
Not directly attributable	–
Total attributable to regulated service	111,375
Distribution and LV cables	
Directly attributable	133,324
Not directly attributable	–
Total attributable to regulated service	133,324
Distribution substations and transformers	
Directly attributable	54,937
Not directly attributable	–
Total attributable to regulated service	54,937
Distribution switchgear	
Directly attributable	22,915
Not directly attributable	–
Total attributable to regulated service	22,915

Other network assets	
Directly attributable	9,686
Not directly attributable	–
Total attributable to regulated service	9,686
Non-network assets	
Directly attributable	481
Not directly attributable	648
Total attributable to regulated service	1,129
Regulated service asset value directly attributable	446,425
Regulated service asset value not directly attributable	648
Total closing RAB value	447,072

For year ended: 31/03/19

Table 3: Allocation of operating costs

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		4,797			
Not directly attributable				–	–
Total attributable to regulated service		4,797			
Vegetation management					
Directly attributable		5,664			
Not directly attributable				–	–
Total attributable to regulated service		5,664			
Routine and corrective maintenance and inspection					
Directly attributable		5,935			
Not directly attributable				–	–
Total attributable to regulated service		5,935			
Asset replacement and renewal					
Directly attributable		352			
Not directly attributable				–	–
Total attributable to regulated service		352			
System operations and network support					
Directly attributable		12,833			
Not directly attributable				–	–
Total attributable to regulated service		12,833			
Business support					
Directly attributable					
Not directly attributable		13,167	903	14,070	–
Total attributable to regulated service		13,167			
Operating costs directly attributable		29,581			
Operating costs not directly attributable	–	13,167	903	14,070	–
Operating expenditure		42,747			

For year ended: 31/03/20

Table 3: Allocation of operating costs

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		3,951			
Not directly attributable				–	–
Total attributable to regulated service		3,951			
Vegetation management					
Directly attributable		5,580			
Not directly attributable				–	–
Total attributable to regulated service		5,580			
Routine and corrective maintenance and inspection					
Directly attributable		7,576			
Not directly attributable				–	–
Total attributable to regulated service		7,576			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		15,037			
Not directly attributable				–	–
Total attributable to regulated service		15,037			
Business support					
Directly attributable					
Not directly attributable		15,299	357	15,656	–
Total attributable to regulated service		15,299			
Operating costs directly attributable		32,143			
Operating costs not directly attributable	–	15,299	357	15,656	–
Operating expenditure		47,443			

For year ended: 31/03/21

Table 3: Allocation of operating costs

	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
	Value allocated ($000s)				
Service interruptions and emergencies					
Directly attributable		4,805			
Not directly attributable				–	–
Total attributable to regulated service		4,805			
Vegetation management					
Directly attributable		5,440			
Not directly attributable				–	–
Total attributable to regulated service		5,440			
Routine and corrective maintenance and inspection					
Directly attributable		9,073			
Not directly attributable				–	–
Total attributable to regulated service		9,073			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		16,129			
Not directly attributable				–	–
Total attributable to regulated service		16,129			
Business support					
Directly attributable					
Not directly attributable		15,195	219	15,414	–
Total attributable to regulated service		15,195			
Operating costs directly attributable		35,448			
Operating costs not directly attributable	–	15,195	219	15,414	–
Operating expenditure		50,643			

Aurora ENERGY

For year ended: 31/03/22

Table 3: Allocation of operating costs

	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
	Value allocated ($000s)				
Service interruptions and emergencies					
Directly attributable		4,870			
Not directly attributable				–	–
Total attributable to regulated service		4,870			
Vegetation management					
Directly attributable		5,663			
Not directly attributable				–	–
Total attributable to regulated service		5,663			
Routine and corrective maintenance and inspection					
Directly attributable		10,772			
Not directly attributable				–	–
Total attributable to regulated service		10,772			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		16,291			
Not directly attributable				–	–
Total attributable to regulated service		16,291			
Business support					
Directly attributable					
Not directly attributable		15,222	54	15,276	–
Total attributable to regulated service		15,222			
Operating costs directly attributable		37,596			
Operating costs not directly attributable	–	15,222	54	15,276	–
Operating expenditure		52,818			

For year ended: 31/03/23

Table 3: Allocation of operating costs

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		4,962			
Not directly attributable				–	–
Total attributable to regulated service		4,962			
Vegetation management					
Directly attributable		5,377			
Not directly attributable				–	–
Total attributable to regulated service		5,377			
Routine and corrective maintenance and inspection					
Directly attributable		10,463			
Not directly attributable				–	–
Total attributable to regulated service		10,463			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		18,356			
Not directly attributable				–	–
Total attributable to regulated service		18,356			
Business support					
Directly attributable					
Not directly attributable		16,714	–	16,714	–
Total attributable to regulated service		16,714			
Operating costs directly attributable		39,159			
Operating costs not directly attributable	–	16,714	–	16,714	–
Operating expenditure		55,873			

For year ended: 31/03/24

Table 3: Allocation of operating costs

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		5,016			
Not directly attributable				–	–
Total attributable to regulated service		5,016			
Vegetation management					
Directly attributable		4,040			
Not directly attributable				–	–
Total attributable to regulated service		4,040			
Routine and corrective maintenance and inspection					
Directly attributable		10,831			
Not directly attributable				–	–
Total attributable to regulated service		10,831			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		17,834			
Not directly attributable				–	–
Total attributable to regulated service		17,834			
Business support					
Directly attributable					
Not directly attributable		16,552	–	16,552	–
Total attributable to regulated service		16,552			
Operating costs directly attributable		37,720			
Operating costs not directly attributable	–	16,552	–	16,552	–
Operating expenditure		54,273			

For year ended: 31/03/25

Table 3: Allocation of operating costs

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		5,068			
Not directly attributable				–	–
Total attributable to regulated service		5,068			
Vegetation management					
Directly attributable		4,048			
Not directly attributable				–	–
Total attributable to regulated service		4,048			
Routine and corrective maintenance and inspection					
Directly attributable		10,008			
Not directly attributable				–	–
Total attributable to regulated service		10,008			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		18,245			
Not directly attributable				–	–
Total attributable to regulated service		18,245			
Business support					
Directly attributable					
Not directly attributable		16,709	–	16,709	–
Total attributable to regulated service		16,709			
Operating costs directly attributable		37,369			
Operating costs not directly attributable	–	16,709	–	16,709	–
Operating expenditure		54,078			

For year ended: 31/03/26

Table 3: Allocation of operating costs

	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
	Value allocated ($000s)				
Service interruptions and emergencies					
Directly attributable		5,080			
Not directly attributable				–	–
Total attributable to regulated service		5,080			
Vegetation management					
Directly attributable		4,025			
Not directly attributable				–	–
Total attributable to regulated service		4,025			
Routine and corrective maintenance and inspection					
Directly attributable		10,222			
Not directly attributable				–	–
Total attributable to regulated service		10,222			
Asset replacement and renewal					
Directly attributable		–			
Not directly attributable				–	–
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		18,248			
Not directly attributable				–	–
Total attributable to regulated service		18,248			
Business support					
Directly attributable					
Not directly attributable		17,071	–	17,071	–
Total attributable to regulated service		17,071			
Operating costs directly attributable		37,575			
Operating costs not directly attributable	–	17,071	–	17,071	–
Operating expenditure		54,645			

Table 5: Rationale for selecting proxy allocator

Tables 5a and 5b must be completed for each line item where proxy allocated is used

Table 5a: Rationale for selecting proxy allocator for asset values

	Asset description	Allocation methodology type	Allocator	Allocator type	Rationale for selecting proxy allocator
Subtransmission lines					
	All costs are Directly Attributable				
Subtransmission cables					
	All costs are Directly Attributable				
Zone substations					
	All costs are Directly Attributable				
Distribution and LV lines					
	All costs are Directly Attributable				
Distribution and LV cables					
	All costs are Directly Attributable				

Distribution substations and transformers

All costs are Directly Attributable				

Distribution switchgear

All costs are Directly Attributable				

Other network assets

All costs are Directly Attributable				

Non-network assets

A causal allocator is used				

Table 5b: Rationale for selecting proxy allocator for operating expenses

Cost description	Allocation methodology type	Cost allocator	Allocator type	Rationale for selecting proxy allocator
Service interruptions and emergencies				
All costs are Directly Attributable				
Vegetation management				
All costs are Directly Attributable				
Routine and corrective maintenance and inspection				
All costs are Directly Attributable				
Asset replacement and renewal				
All costs are Directly Attributable				
System operations and network support				
All costs are Directly Attributable				
Business support				
A causal allocator is used				

Appendix O. IM Schedule E – Capex, Opex, Demand

977. This appendix includes the following tables

- Table 1: Projects and programmes
- Table 2: Capex Summary
- Table 3: Opex Summary
- Table 4: Capex projects and programmes
- Table 5: Capex by asset categories
- Table 6: Opex projects and programmes
- Table 7: Non-network opex
- Table 8: Aggregate forecast commissioned by asset categories
- Table 9: Cost escalation factors
- Table 10: Network demand forecasts

Table 1: Projects and programmes

Table 1a Summary of all capex projects and programmes

Number	Project reference	Project/programme name	Capex category	Brief description of project/programme	Forecast costs in constant prices $(000)	Reference to primary supporting information
1	1	1.1 Poles	Asset replacement and renewal	Renewals capex on Poles	47,868	POD01 - Poles.pdf
2	2	1.2 Crossarms	Asset replacement and renewal	Renewals capex on Crossarms	38,306	POD02 - Crossarms.pdf
3	3	2.1 Subtransmission Conductor	Asset replacement and renewal	Renewals capex on Subtransmission Conductor	16,262	Application - Appendix E. Renewals Capex
4	4	2.2 Distribution Conductor	Asset replacement and renewal	Renewals capex on Distribution Conductor	28,059	POD04 - Distribution Conductor.pdf
5	5	2.3 Low Voltage Conductor	Asset replacement and renewal	Renewals capex on Low Voltage Conductor	19,631	POD05 - LV Conductor.pdf
6	6	3.1 Subtransmission Cables	Asset replacement and renewal	Renewals capex on Subtransmission Cables	12,118	Application - Appendix E. Renewals Capex
7	7	3.2 Distribution Cables	Asset replacement and renewal	Renewals capex on Distribution Cables	9,362	Application - Appendix E. Renewals Capex
8	8	3.3 Low Voltage Cables	Asset replacement and renewal	Renewals capex on Low Voltage Cables	2,801	Application - Appendix E. Renewals Capex
9	9	4.1 Zone Substations	Asset replacement and renewal	Renewals capex on Zone Substations	41,948	POD09 - Zone Substations.pdf
10	14	5.1 Ground Mounted Switchgear	Asset replacement and renewal	Renewals capex on Ground Mounted Switchgear	14,468	Application - Appendix E. Renewals Capex
11	15	5.2 Pole Mounted Fuses	Asset replacement and renewal	Renewals capex on Pole Mounted Fuses	1,350	Application - Appendix E. Renewals Capex
12	16	5.3 Pole Mounted Switches	Asset replacement and renewal	Renewals capex on Pole Mounted Switches	2,764	Application - Appendix E. Renewals Capex
13	18	5.4 Low Voltage Enclosures	Asset replacement and renewal	Renewals capex on Low Voltage Enclosures	9,030	POD18 - LV Enclosures.pdf
14	19	5.6 Ancillary Distribution Substation Equipment	Asset replacement and renewal	Renewals capex on Ancillary Distribution Substation Equipment	5,323	Application - Appendix E. Renewals Capex
15	20	6.1 Ground Mounted Distribution Transformers	Asset replacement and renewal	Renewals capex on Ground Mounted Distribution Transformers	1,686	Application - Appendix E. Renewals Capex
16	21	6.2 Pole Mounted Distribution Transformers	Asset replacement and renewal	Renewals capex on Pole Mounted Distribution Transformers	16,658	Application - Appendix E. Renewals Capex
17	24	7.1 Protection	Asset replacement and renewal	Renewals capex on Protection	9,290	POD24 - Protection.pdf
18	25	7.2 DC Systems	Asset replacement and renewal	Renewals capex on DC Systems	3,841	Application - Appendix E. Renewals Capex
19	26	7.3 Remote Terminal Units	Asset replacement and renewal	Renewals capex on Remote Terminal Units	1,008	Application - Appendix E. Renewals Capex
20	30	9 Distribution and LV Reinforcement	System growth	Reinforcement of the Distribution and LV network	14,011	Application - Appendix F. Growth and Security Capex
21	31	8.1 Arrowtown 33kV Ring Upgrade	System growth	New 33kV feeder on Arrowtown Ring	5,433	POD31 - Arrowtown 33kV Ring Upgrade.pdf
22	32	8.2 Arrowtown Zone Substation 33kV Indoor Switchboard	System growth	New 33kV indoor switchboard at Arrowtown	2,648	Application - Appendix F. Growth and Security Capex
23	33	8.3 Omakau New Zone Substation	System growth	New Omakau zone substation	3,003	Application - Appendix F. Growth and Security Capex
24	39	8.16 Smith Street to Willowbank Inter-tie	System growth	New 33kV cable between Smith St and Willowbank	5,209	Application - Appendix F. Growth and Security Capex
25	50	10 Consumer connection (net)	Consumer connection	Consumer connections expenditure	56,377	POD50 - Consumer Connection.pdf
26	51	11 Asset relocations (net)	Asset relocations and undergrounding	Asset relocations expenditure	9,586	Application - Appendix G. Other Network Capex
27	52	13 RSE	Quality of supply	Reliability focussed investment including network automation	1,357	Application - Appendix G. Other Network Capex
28	53	12 Future Networks	Quality of supply	Work to prepare for uptake of new technology	1,367	Application - Appendix G. Other Network Capex
29	60	14 IT	Non-network CAPEX	ICT capex	12,500	POD60 - ICT.pdf
30	61	15 Facilities	Non-network CAPEX	Facilities capex	3,964	Application - Appendix I. Non-network Expenditure

Table 1b Summary of all opex projects and programmes

Number	Project reference	Project/programme name	Opex category	Brief description of project/programme	Forecast costs in constant prices $(000)	Reference to primary supporting information
1	70	16 Preventive Maintenance	Routine and corrective maintenance and inspection	Preventive maintenance operating expenditure	30,531	POD70 - Preventive Maintenance.pdf
2	71	17 Corrective Maintenance	Routine and corrective maintenance and inspection	Corrective maintenance operating expenditure	17,059	POD71 - Corrective Maintenance.pdf
3	72	18 Reactive Maintenance	Service interruptions and emergencies	Reactive maintenance operating expenditure	22,755	POD72 - Reactive Maintenance.pdf
4	73	19 Vegetation	Vegetation management	Vegetation management operating expenditure	21,186	POD73 - Vegetation Management.pdf
5	80	20 SONS	System operations and network support	System operations and network support expenditure	78,233	POD80 - SONS.pdf
6	81	21 People Costs	Business support	People costs operating expenditure	40,293	POD81 - PEOPLE.pdf
7	82	22 IT Opex	Business support	ICT operating expenditure	17,032	Application - Appendix I. Non-network Expenditure
8	83	23 Premises and Plant	Business support	Premises, plant and insurance operating expenditure	1,955	Application - Appendix I. Non-network Expenditure
9	84	24 Administration and Governance	Business support	Governance and administration operating expenditure	15,560	Application - Appendix I. Non-network Expenditure
10	85	25 Upper Clutha DER Solution	System operations and network support	Demand response operating expenditure for Upper Clutha growth con	3,001	Application - Appendix I. Non-network Expenditure

Aurora ENERGY

Table 2: Capex summary

2a Actual and forecast capex in constant prices $(000)

Capex Categories	Current period					Assessment Period		CPP Regulatory Period					Total CPP
	CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
	$000 (in constant prices)												
Consumer connection	10,911	11,196	7,899	8,776	18,045	14,351	9,092	8,524	8,524	11,365	12,935	15,028	56,377
System growth	7,343	9,527	284	6,554	8,387	7,250	5,238	3,879	9,332	9,247	4,680	3,165	30,303
Asset replacement and renewal	7,984	5,846	19,026	52,452	40,624	36,713	49,776	58,078	61,426	59,982	54,849	47,436	281,771
Asset relocations	2,735	2,193	2,184	1,072	1,402	1,242	1,917	1,917	1,917	1,917	1,917	1,917	9,586
Reliability, safety and environment:													
Quality of supply	1,641	1,781	1,375	-	-	1,157	236	458	458	226	904	678	2,724
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	428	267	864	1,756	1,930	-	-	-	-	-	-	-	-
Total reliability, safety and environment	**2,069**	**2,047**	**2,239**	**1,756**	**1,930**	**1,157**	**236**	**458**	**458**	**226**	**904**	**678**	**2,724**
Total expenditure on network assets	**31,042**	**30,809**	**31,632**	**70,610**	**70,388**	**60,714**	**66,260**	**72,856**	**81,657**	**82,737**	**75,286**	**68,225**	**380,761**
Total expenditure on non-network assets	-	-	-	988	654	8,615	6,237	6,408	2,932	2,771	2,264	2,089	16,465
Total expenditure on assets	**31,042**	**30,809**	**31,632**	**71,599**	**71,041**	**69,329**	**72,497**	**79,264**	**84,590**	**85,507**	**77,550**	**70,314**	**397,226**

2b Actual and forecast capex in nominal prices $(000)

Capex Categories	Current period					Assessment Period		CPP Regulatory Period					Total CPP
	CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
	$000 (in nominal prices)												
Consumer connection	10,250	10,553	7,526	8,494	17,761	14,351	9,241	8,788	8,929	12,110	13,988	16,494	60,309
System growth	6,898	8,980	270	6,343	8,255	7,250	5,355	4,038	9,961	10,058	5,180	3,580	32,818
Asset replacement and renewal	7,501	5,511	18,128	50,767	39,985	36,713	50,850	60,385	65,215	64,854	60,245	53,312	304,012
Asset relocations	2,570	2,067	2,081	1,037	1,380	1,242	1,962	2,002	2,046	2,095	2,138	2,182	10,463
Reliability, safety and environment:													
Quality of supply	1,541	1,678	1,310	-	-	1,157	242	478	488	245	1,006	772	2,988
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	402	251	823	1,700	1,899	-	-	-	-	-	-	-	-
Total reliability, safety and environment	**1,944**	**1,930**	**2,133**	**1,700**	**1,899**	**1,157**	**242**	**478**	**488**	**245**	**1,006**	**772**	**2,988**
Total expenditure on network assets	**29,162**	**29,040**	**30,138**	**68,341**	**69,280**	**60,714**	**67,650**	**75,691**	**86,639**	**89,362**	**82,557**	**76,340**	**410,590**
Expenditure on non-network assets	-	-	-	956	643	8,615	6,379	6,690	3,122	3,006	2,502	2,355	17,675
Total expenditure on assets	29,162	29,040	30,138	69,298	69,923	69,329	74,029	82,381	89,761	92,368	85,060	78,695	428,265
plus Cost of financing	-	-	-	-	-	776	903	631	939	740	659	545	3,513
less Value of capital contributions	4,435	6,114	3,499	4,751	3,875	9,702	6,722	6,474	6,585	8,523	9,676	11,205	42,463
plus Value of vested assets	-	-	-	-	-	-	-	-	-	-	-	-	-
Total capital expenditure	**24,727**	**22,926**	**26,639**	**64,547**	**66,048**	**60,403**	**68,210**	**76,538**	**84,114**	**84,585**	**76,043**	**68,035**	**389,315**

2c Actual and forecast commissioned asset values in nominal prices $(000)

Capex Categories	Current period					Assessment Period		CPP Regulatory Period					Total CPP
	CY-4	*CY-3*	*CY-2*	*CY-1*	*CY0*	*CA*	*CA+1*	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*	
	$000 (in nominal prices)												
Consumer connection	7,639	9,657	5,465	8,128	9,566	4,634	3,749	3,661	3,651	4,690	5,866	6,875	24,744
System growth	5,141	8,213	250	1,071	12,410	3,626	7,589	3,237	2,562	18,722	6,617	3,731	34,869
Asset replacement and renewal	5,590	5,040	13,289	42,948	41,531	42,291	54,796	65,633	62,994	63,869	62,790	57,706	312,992
Asset relocations and undergrounding	1,915	1,871	1,525	827	1,205	770	796	834	837	811	897	910	4,288
Reliability, safety and environment:													
Quality of supply	1,149	1,535	960	-	-	1,062	245	498	498	237	1,054	804	3,092
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	300	230	603	1,355	1,658	-	-	-	-	-	-	-	-
Total reliability, safety and environment	**1,448**	**1,765**	**1,564**	**1,355**	**1,658**	**1,062**	**245**	**498**	**498**	**237**	**1,054**	**804**	**3,092**
Total forecast network capex	21,732	26,547	22,093	54,329	66,370	52,384	67,174	73,863	70,542	88,330	77,224	70,027	379,985
Total forecast non-network capex	-	-	-	922	510	8,309	4,600	8,854	3,185	2,926	2,617	2,455	20,037
Total value of commissioned assets	**21,732**	**26,547**	**22,093**	**55,251**	**66,880**	**60,693**	**71,774**	**82,718**	**73,727**	**91,256**	**79,840**	**72,481**	**400,022**

2d Actual and forecast commissioned asset values by provider in nominal prices ($000)

	CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	Total CPP
EDB													-
Related party	13,195	15,303	11,509	14,892	28,219	17,182	13,563	13,355	11,294	14,056	-	-	38,706
Other sources	8,537	11,244	10,584	40,359	38,660	43,511	58,211	69,362	62,432	77,200	79,840	72,481	361,316
Unknown													-
Total value of commissioned assets	**21,732**	**26,547**	**22,093**	**55,251**	**66,880**	**60,693**	**71,774**	**82,718**	**73,727**	**91,256**	**79,840**	**72,481**	**400,022**

Totals in table 2c and table 2d must reconcile.

Table 3: Opex summary

3a Actual and forecast opex in constant prices $(000)

Opex Categories	Current period					Assessment Period		CPP Regulatory Period					Total CPP period
	CY-4	*CY-3*	*CY-2*	*CY-1*	*CY0*	*CA*	*CA+1*	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*	
	$(000) in constant prices												
Service interruptions and emergencies	4,380	4,408	5,912	4,392	4,874	3,951	4,683	4,645	4,621	4,557	4,507	4,426	22,755
Vegetation management	3,852	5,567	3,882	5,700	5,755	5,580	5,301	5,401	5,008	3,670	3,600	3,507	21,186
Routine and corrective maintenance and inspection	4,299	5,415	6,749	5,975	6,030	7,576	8,835	10,260	9,728	9,827	8,886	8,890	47,591
Asset replacement and renewal	620	948	293	657	358	-	-	-	-	-	-	-	-
Total network opex	**13,152**	**16,338**	**16,836**	**16,724**	**17,016**	**17,106**	**18,819**	**20,306**	**19,357**	**18,053**	**16,992**	**16,823**	**91,532**
System operations and network support	4,106	3,971	4,059	11,037	13,038	15,037	15,744	15,589	17,158	16,245	16,277	15,966	81,235
Business support	5,928	6,384	7,919	9,719	13,377	15,299	14,807	14,517	15,566	15,035	14,854	14,868	74,839
Total non-network opex	**10,034**	**10,355**	**11,977**	**20,757**	**26,415**	**30,337**	**30,551**	**30,106**	**32,723**	**31,280**	**31,132**	**30,833**	**156,074**
Total operating expenditure	**23,185**	**26,694**	**28,813**	**37,481**	**43,431**	**47,443**	**49,370**	**50,412**	**52,080**	**49,333**	**48,124**	**47,656**	**247,606**

3b Actual and forecast opex in nominal prices $(000)

Opex Categories	Current period					Assessment Period		CPP Regulatory Period					Total CPP period
	CY-4	*CY-3*	*CY-2*	*CY-1*	*CY0*	*CA*	*CA+1*	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*	
	$(000) in nominal prices												
Service interruptions and emergencies	4,115	4,155	5,633	4,251	4,797	3,951	4,805	4,870	4,962	5,016	5,068	5,080	24,996
Vegetation management	3,619	5,247	3,699	5,517	5,664	5,580	5,440	5,663	5,377	4,040	4,048	4,025	23,153
Routine and corrective maintenance and inspection	4,039	5,104	6,430	5,783	5,935	7,576	9,073	10,772	10,463	10,831	10,008	10,222	52,296
Asset replacement and renewal	582	894	279	636	352	-	-	-	-	-	-	-	-
Total network opex	**12,355**	**15,400**	**16,041**	**16,187**	**16,748**	**17,106**	**19,319**	**21,306**	**20,802**	**19,887**	**19,124**	**19,327**	**100,445**
System operations and network support	3,857	3,743	3,867	10,683	12,833	15,037	16,129	16,291	18,356	17,834	18,245	18,248	88,973
Business support	5,569	6,018	7,545	9,407	13,167	15,299	15,195	15,222	16,714	16,552	16,709	17,071	82,268
Total non-network opex	**9,426**	**9,761**	**11,412**	**20,090**	**25,999**	**30,337**	**31,324**	**31,512**	**35,070**	**34,386**	**34,954**	**35,318**	**171,241**
Total operating expenditure	**21,781**	**25,161**	**27,453**	**36,277**	**42,747**	**47,443**	**50,643**	**52,818**	**55,873**	**54,273**	**54,078**	**54,645**	**271,687**

3c Actual and forecast opex by provider (optional)

EDB													-
Related party	20,533	23,931	24,923	18,799	17,851	14,810	15,127	16,262	14,852	14,026	228	234	45,602
Other sources	1,248	1,230	2,530	17,478	24,897	32,633	35,516	36,555	41,021	40,246	53,850	54,412	226,084
Unknown													-

Table 4: Capex projects and programmes

Actual and forecast capex in constant prices $(000)

Project reference	Project/programme name	CY-4 (Current period)	CY-3	CY-2	CY-1	CY0	CA (Assessment Period)	CA+1	Year 1 (CPP Regulatory Period)	Year 2	Year 3	Year 4	Year 5	Total CPP Period
4a Consumer connection														
	Consumer types defined by EDB													
	10 Consumer connection (net)	10,911	11,196	7,899	8,776	18,045	14,351	9,092	8,524	8,524	11,365	12,935	15,028	56,377
	Total consumer connection expenditure	**10,911**	**11,196**	**7,899**	**8,776**	**18,045**	**14,351**	**9,092**	**8,524**	**8,524**	**11,365**	**12,935**	**15,028**	**56,377**
	less Capital contributions funding consumer connection	3,816	5,346	3,048	4,631	3,563	9,300	5,455	5,114	5,114	6,819	7,761	9,017	33,826
	Total consumer connection less capital contributions	**7,095**	**5,850**	**4,851**	**4,145**	**14,482**	**5,052**	**3,637**	**3,410**	**3,410**	**4,546**	**5,174**	**6,011**	**22,551**
4b System growth														
	Major Projects	7,343	5,556	284	4,419	7,678								-
	8.1 Arrowtown 33kV Ring Upgrade						-	640	-	3,947	1,485	-	-	5,433
	8.2 Arrowtown Zone Substation 33kV Indoor Switchboard						-	-	-	-	1,059	1,589	-	2,648
	8.3 Omakau New Zone Substation						-	100	896	-	2,108	-	-	3,003
	8.5 Lindis Crossing Second Transformer						-	-	-	-	-	-	-	-
	8.7 Upper Clutha Voltage Support						-	922	-	-	-	-	-	-
	8.16 Smith Street to Willowbank Inter-tie						-	470	-	3,029	2,180	-	-	5,209
	8.17 North City to Ward Inter-tie						-	-	-	-	-	-	-	-
	9 Distribution and LV Reinforcement	-	3,971	-	2,135	709	3,921	2,906	2,983	2,356	2,415	3,092	3,165	14,011
	Install two new 24MVA transformers at Cromwell substation						3,297	200	-	-	-	-	-	-
	Riverbank Road Switching Station						32	-	-	-	-	-	-	-
	Total system growth expenditure	**7,343**	**9,527**	**284**	**6,554**	**8,387**	**7,250**	**5,238**	**3,879**	**9,332**	**9,247**	**4,680**	**3,165**	**30,303**
	less Capital contributions funding system growth	18	24	29	-	-	-	-	-	-	-	-	-	-
	Total system growth less capital contributions	**7,325**	**9,504**	**255**	**6,554**	**8,387**	**7,250**	**5,238**	**3,879**	**9,332**	**9,247**	**4,680**	**3,165**	**30,303**
4c Asset replacement and renewal by projects or programmes														
	1.1 Poles	4,655	3,907	8,245	41,156	27,012	14,198	14,352	12,780	11,472	10,908	6,660	6,048	47,868
	1.2 Crossarms	-	-	-	-	-	1,141	3,661	6,563	8,249	8,083	7,829	7,582	38,306
	2.1 Subtransmission Conductor	-	-	-	-	-	939	6,770	6,622	7,875	958	398	408	16,262
	2.2 Distribution Conductor	-	-	-	-	-	4,172	4,184	4,692	5,538	5,969	6,134	5,727	28,059
	2.3 Low Voltage Conductor	336	-	26	195	31	-	-	2,268	4,108	4,271	4,523	4,460	19,631
	3.1 Subtransmission Cables	70	48	211	2,183	1,329	2,703	200	-	1,996	2,994	2,851	4,277	12,118
	3.2 Distribution Cables	170	154	333	487	74	1,035	851	2,018	2,079	2,112	1,942	1,210	9,362
	3.3 Low Voltage Cables	150	318	423	281	223	252	397	445	499	560	609	687	2,801
	4.1 Zone Substations	446	276	966	6,150	4,283	6,166	8,752	10,495	5,774	10,256	10,435	4,987	41,948
	5.1 Ground Mounted Switchgear	111	113	325	86	-	1,223	3,098	3,098	3,225	3,120	3,150	1,875	14,468
	5.2 Pole Mounted Fuses	96	39	374	174	706	75	215	245	260	275	285	285	1,350
	5.3 Pole Mounted Switches	14	-	129	-	-	301	382	588	588	588	529	470	2,764
	5.4 Low Voltage Enclosures	-	-	-	-	-	575	1,415	1,896	1,965	1,954	1,753	1,463	9,030
	5.6 Ancillary Distribution Substation Equipment	-	-	-	-	-	876	772	772	1,288	1,088	1,088	1,088	5,323
	6.1 Ground Mounted Distribution Transformers	354	462	365	513	143	101	218	326	326	326	326	381	1,686
	6.2 Pole Mounted Distribution Transformers	280	110	20	9	183	1,359	1,471	2,146	2,982	3,600	3,900	4,029	16,658
	6.4 Mobile Distribution Substations and Generators	-	-	-	-	-	38	-	-	-	-	-	-	-
	7.1 Protection	2	1	5	50	2,904	1,260	2,360	2,360	2,360	1,930	1,320	1,320	9,290
	7.2 DC Systems	-	-	-	-	173	300	679	679	758	758	823	823	3,841
	7.3 Remote Terminal Units	1,300	418	7,604	1,169	3,563	-	-	84	84	231	294	315	1,008
	Total asset replacement and renewal expenditure	**7,984**	**5,846**	**19,026**	**52,452**	**40,624**	**36,713**	**49,776**	**58,078**	**61,426**	**59,982**	**54,849**	**47,436**	**281,771**
	less Capital contributions funding asset replacement and renewal	-	28	36	0	22	-	-	-	-	-	-	-	-
	Total asset replacement and renewal less capital contributions	**7,984**	**5,818**	**18,990**	**52,452**	**40,602**	**36,713**	**49,776**	**58,078**	**61,426**	**59,982**	**54,849**	**47,436**	**281,771**
4d Asset relocations														
	*Project or programme**													
	11 Asset relocations (net)	2,735	2,193	2,184	1,072	1,402	1,242	1,917	1,917	1,917	1,917	1,917	1,917	9,586
	*include additional rows if needed													
	Total asset relocations expenditure	**2,735**	**2,193**	**2,184**	**1,072**	**1,402**	**1,242**	**1,917**	**1,917**	**1,917**	**1,917**	**1,917**	**1,917**	**9,586**
	less Capital contributions funding asset relocations	887	1,084	517	277	328	402	1,150	1,150	1,150	1,150	1,150	1,150	5,751
	Asset relocations less capital contributions	**1,848**	**1,109**	**1,667**	**795**	**1,074**	**840**	**767**	**767**	**767**	**767**	**767**	**767**	**3,834**
4e Reliability, safety and environment:														
4e1 Quality of supply														
	*Project or programme**													
	12 Future Networks	-	-	-	-	-	-	236	458	458	226	226	-	1,367
	13 RSE	2,069	2,047	2,239	1,756	1,930	1,157	-	-	-	-	678	678	1,357
	*include additional rows if needed													
	Total quality of supply expenditure	**2,069**	**2,047**	**2,239**	**1,756**	**1,930**	**1,157**	**236**	**458**	**458**	**226**	**904**	**678**	**2,724**
	less Capital contributions funding quality of supply	-	5	42	-	24	-	-	-	-	-	-	-	-
	Quality of supply less capital contributions	**2,069**	**2,042**	**2,197**	**1,756**	**1,905**	**1,157**	**236**	**458**	**458**	**226**	**904**	**678**	**2,724**
4e2 Legislative and regulatory														
	*Project or programme**													
		-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
	*include additional rows if needed													
	Total legislative and regulatory expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-
	less Capital contributions funding legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-
	Legislative and regulatory less capital contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
4e3 Other reliability, safety and environment														
	*Project or programme**													
		-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
	*include additional rows if needed													
	Total other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-	-	-
	less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment less capital contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
4f Non-network assets														
4f1 Routine non-network expenditure														
	*Project or programme**													
	14 IT	-	-	-	346	295	4,489	5,005	5,360	2,090	1,876	1,675	1,500	12,500
	15 Facilities	-	-	-	642	359	4,126	1,232	1,049	842	895	589	589	3,964
	*include additional rows if needed													
4f2 Non-network assets - atypical expenditure														
	*Project or programme**													
		-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-
	*include additional rows if needed													
	Total atypical non-network	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total capex non-network assets	-	-	-	**988**	**654**	**8,615**	**6,237**	**6,408**	**2,932**	**2,771**	**2,264**	**2,089**	**16,465**
	Total capex network assets	**31,042**	**30,809**	**31,632**	**70,610**	**70,388**	**60,714**	**66,260**	**72,856**	**81,657**	**82,737**	**75,286**	**68,225**	**380,761**
	Total capex network assets less capital contributions	**26,322**	**24,322**	**27,959**	**65,702**	**66,451**	**51,012**	**59,654**	**66,591**	**75,392**	**74,767**	**66,375**	**58,057**	**341,183**

Actual and forecast capex in nominal prices $(000)

Project/programme name	CY-4 (Current period)	CY-3	CY-2	CY-1	CY0	CA (Assessment Period)	CA+1	Year 1 (CPP Regulatory Period)	Year 2	Year 3	Year 4	Year 5	Total CPP Period
10 Consumer connection (net)	10,250	10,553	7,526	8,494	17,761	14,351	9,241	8,788	8,929	12,110	13,988	16,494	60,309
Total consumer connection expenditure	**10,250**	**10,553**	**7,526**	**8,494**	**17,761**	**14,351**	**9,241**	**8,788**	**8,929**	**12,110**	**13,988**	**16,494**	**60,309**
less Capital contributions funding consumer connection	3,584	5,039	2,904	4,482	3,507	9,300	5,545	5,273	5,357	7,266	8,393	9,896	36,185
Total consumer connection less capital contributions	**6,666**	**5,514**	**4,622**	**4,012**	**14,254**	**5,052**	**3,696**	**3,515**	**3,571**	**4,844**	**5,595**	**6,597**	**24,123**
Major Projects	6,898	5,237	270	4,277	7,557								-
8.1 Arrowtown 33kV Ring Upgrade						-	656	-	4,235	1,636	-	-	5,871
8.2 Arrowtown Zone Substation 33kV Indoor Switchboard						-	-	-	-	1,145	1,749	-	2,895
8.3 Omakau New Zone Substation						-	102	930	-	2,278	-	-	3,208
8.5 Lindis Crossing Second Transformer						-	-	-	-	-	-	-	-
8.7 Upper Clutha Voltage Support						-	944	-	-	-	-	-	-
8.16 Smith Street to Willowbank Inter-tie						-	480	-	3,220	2,371	-	-	5,590
8.17 North City to Ward Inter-tie						-	-	-	-	-	-	-	-
9 Distribution and LV Reinforcement	-	3,743	-	2,067	698	3,921	2,970	3,108	2,506	2,628	3,431	3,580	15,253
Install two new 24MVA transformers at Cromwell substation						3,297	202	-	-	-	-	-	-
Riverbank Road Switching Station						32	-	-	-	-	-	-	-
Total system growth expenditure	**6,898**	**8,980**	**270**	**6,343**	**8,255**	**7,250**	**5,355**	**4,038**	**9,961**	**10,058**	**5,180**	**3,580**	**32,818**
less Capital contributions funding system growth	17	22	27	-	-	-	-	-	-	-	-	-	-
Total system growth less capital contributions	**6,881**	**8,958**	**243**	**6,343**	**8,255**	**7,250**	**5,355**	**4,038**	**9,961**	**10,058**	**5,180**	**3,580**	**32,818**
1.1 Poles	4,373	3,683	7,856	39,833	26,587	14,198	14,701	13,367	12,270	11,942	7,442	6,898	51,919
1.2 Crossarms	-	-	-	-	-	1,141	3,750	6,864	8,823	8,850	8,748	8,648	41,933
2.1 Subtransmission Conductor	-	-	-	-	-	939	6,941	6,936	8,454	1,057	449	470	17,366
2.2 Distribution Conductor	-	-	-	-	-	4,172	4,289	4,914	5,945	6,580	6,915	6,597	30,951
2.3 Low Voltage Conductor	316	-	25	189	31	-	-	2,376	4,410	4,709	5,100	5,138	21,732
3.1 Subtransmission Cables	66	46	201	2,113	1,308	2,703	205	-	2,141	3,295	3,209	4,918	13,563
3.2 Distribution Cables	160	145	318	471	73	1,035	856	2,040	2,114	2,163	1,998	1,252	9,568
3.3 Low Voltage Cables	141	300	403	272	220	252	407	466	535	616	685	789	3,091
4.1 Zone Substations	419	260	920	5,952	4,216	6,166	8,907	10,834	6,021	10,892	11,219	5,459	44,426
5.1 Ground Mounted Switchgear	104	106	309	83	-	1,223	3,129	3,157	3,320	3,247	3,309	1,988	15,021
5.2 Pole Mounted Fuses	90	36	357	168	694	75	220	256	278	301	318	325	1,479
5.3 Pole Mounted Switches	13	-	123	-	-	301	391	614	627	640	587	533	3,002
5.4 Low Voltage Enclosures	-	-	-	-	-	575	1,449	1,983	2,102	2,139	1,959	1,668	9,850
5.6 Ancillary Distribution Substation Equipment	-	-	-	-	-	876	791	808	1,377	1,191	1,216	1,241	5,832
6.1 Ground Mounted Distribution Transformers	332	436	348	497	141	101	219	330	332	334	336	394	1,726
6.2 Pole Mounted Distribution Transformers	263	104	19	9	180	1,359	1,480	2,170	3,033	3,686	4,013	4,170	17,072
6.4 Mobile Distribution Substations and Generators	-	-	-	-	-	38	-	-	-	-	-	-	
7.1 Protection	2	1	5	48	2,858	1,260	2,420	2,471	2,531	2,124	1,485	1,516	10,128
7.2 DC Systems	-	-	-	-	171	300	696	711	813	834	926	946	4,229
7.3 Remote Terminal Units	1,221	394	7,245	1,131	3,506	-	-	88	90	254	331	362	1,125
Total asset replacement and renewal expenditure	**7,501**	**5,511**	**18,128**	**50,767**	**39,985**	**36,713**	**50,850**	**60,385**	**65,215**	**64,854**	**60,245**	**53,312**	**304,012**
less Capital contributions funding asset replacement and renewal	-	26	35	0	21	-	-	-	-	-	-	-	-
Total asset replacement and renewal less capital contributions	**7,501**	**5,484**	**18,093**	**50,766**	**39,963**	**36,713**	**50,850**	**60,385**	**65,215**	**64,854**	**60,245**	**53,312**	**304,012**
11 Asset relocations (net)	2,570	2,067	2,081	1,037	1,380	1,242	1,962	2,002	2,046	2,095	2,138	2,182	10,463
Total asset relocations expenditure	**2,570**	**2,067**	**2,081**	**1,037**	**1,380**	**1,242**	**1,962**	**2,002**	**2,046**	**2,095**	**2,138**	**2,182**	**10,463**
less Capital contributions funding asset relocations	833	1,021	493	268	323	402	1,177	1,201	1,228	1,257	1,283	1,309	6,278
Asset relocations less capital contributions	**1,736**	**1,045**	**1,588**	**769**	**1,057**	**840**	**785**	**801**	**819**	**838**	**855**	**873**	**4,185**
12 Future Networks	-	-	-	-	-	-	242	478	488	245	249	-	1,460
13 RSE	1,944	1,930	2,133	1,700	1,899	1,157	-	-	-	-	756	772	1,528
Total quality of supply expenditure	**1,944**	**1,930**	**2,133**	**1,700**	**1,899**	**1,157**	**242**	**478**	**488**	**245**	**1,006**	**772**	**2,988**
less Capital contributions funding quality of supply	-	5	40	-	24	-	-	-	-	-	-	-	-
Quality of supply less capital contributions	**1,944**	**1,925**	**2,093**	**1,700**	**1,875**	**1,157**	**242**	**478**	**488**	**245**	**1,006**	**772**	**2,988**
4e2 project rows	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total legislative and regulatory expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory less capital contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
4e3 project rows	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
14 IT	-	-	-	335	290	4,489	5,119	5,595	2,225	2,035	1,851	1,691	13,397
15 Facilities	-	-	-	622	353	4,126	1,260	1,095	897	971	651	664	4,278
4f2 project rows	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total atypical non-network	-	-	-	-	-	-	-	-	-	-	-	-	-
Total capex non-network assets	-	-	-	**956**	**643**	**8,615**	**6,379**	**6,690**	**3,122**	**3,006**	**2,502**	**2,355**	**17,675**
Total capex network assets	**29,162**	**29,040**	**30,138**	**68,341**	**69,280**	**60,714**	**67,650**	**75,691**	**86,639**	**89,362**	**82,557**	**76,340**	**410,590**
Total capex network assets less capital contributions	**24,727**	**22,926**	**26,639**	**63,590**	**65,404**	**51,012**	**60,928**	**69,217**	**80,054**	**80,839**	**72,882**	**65,135**	**368,127**

Forecast commissioned assets values in nominal terms $(000)

Project/programme name	CA (Assessment Period)	CA+1	Year 1 (CPP Regulatory Period)	Year 2	Year 3	Year 4	Year 5	Total CPP Period
10 Consumer connection (net)	10,274	11,611	9,713	8,972	11,296	13,859	16,231	60,071
Total consumer connection expenditure	**10,274**	**11,611**	**9,713**	**8,972**	**11,296**	**13,859**	**16,231**	**60,071**
less Capital contributions funding consumer connection	5,640	7,863	6,052	5,321	6,605	7,993	9,356	35,327
Total consumer connection less capital contributions	**4,634**	**3,749**	**3,661**	**3,651**	**4,690**	**5,866**	**6,875**	**24,744**
Major Projects								-
8.1 Arrowtown 33kV Ring Upgrade	-	5	-	23	6,697	-	-	6,721
8.2 Arrowtown Zone Substation 33kV Indoor Switchboard	-	-	-	-	7	3,020	-	3,027
8.3 Omakau New Zone Substation	-	1	6	-	3,315	-	-	3,321
8.5 Lindis Crossing Second Transformer	-	-	-	-	-	-	-	-
8.7 Upper Clutha Voltage Support	-	956	-	-	-	-	-	-
8.16 Smith Street to Willowbank Inter-tie	-	4	-	18	6,161	-	-	6,179
8.17 North City to Ward Inter-tie	-	-	-	-	-	-	-	-
9 Distribution and LV Reinforcement	3,573	3,005	3,231	2,521	2,542	3,597	3,731	15,623
Install two new 24MVA transformers at Cromwell substation	24	3,619	-	-	-	-	-	-
Riverbank Road Switching Station	30	-	-	-	-	-	-	-
Total system growth expenditure	**3,626**	**7,589**	**3,237**	**2,562**	**18,722**	**6,617**	**3,731**	**34,869**
less Capital contributions funding system growth	-	-	-	-	-	-	-	-
Total system growth less capital contributions	**3,626**	**7,589**	**3,237**	**2,562**	**18,722**	**6,617**	**3,731**	**34,869**
1.1 Poles	16,272	15,918	13,920	12,536	11,558	7,798	7,186	52,998
1.2 Crossarms	1,046	3,800	7,148	9,014	8,565	9,166	9,009	42,902
2.1 Subtransmission Conductor	861	7,034	7,223	8,637	1,023	470	490	17,843
2.2 Distribution Conductor	3,824	4,347	5,118	6,074	6,368	7,245	6,872	31,677
2.3 Low Voltage Conductor	-	-	2,474	4,505	4,557	5,343	5,352	22,231
3.1 Subtransmission Cables	20	6,477	-	12	5,406	19	8,447	13,883
3.2 Distribution Cables	949	867	2,125	2,161	2,094	2,095	1,305	9,780
3.3 Low Voltage Cables	231	412	485	547	596	717	822	3,167
4.1 Zone Substations	5,653	5,001	14,028	4,687	9,424	14,763	4,529	47,432
5.1 Ground Mounted Switchgear	1,121	3,171	3,289	3,393	3,143	3,468	2,072	15,365
5.2 Pole Mounted Fuses	69	223	267	284	291	334	339	1,515
5.3 Pole Mounted Switches	276	396	640	641	620	616	555	3,071
5.4 Low Voltage Enclosures	527	1,469	2,065	2,147	2,070	2,053	1,738	10,072
5.6 Ancillary Distribution Substation Equipment	804	802	841	1,407	1,153	1,274	1,292	5,967
6.1 Ground Mounted Distribution Transformers	93	222	344	339	324	352	411	1,769
6.2 Pole Mounted Distribution Transformers	1,246	1,500	2,260	3,099	3,569	4,207	4,347	17,482
6.4 Mobile Distribution Substations and Generators	35	-	-	-	-	-	-	
7.1 Protection	8,992	2,452	2,573	2,586	2,056	1,556	1,579	10,350
7.2 DC Systems	275	705	740	830	807	970	985	4,333
7.3 Remote Terminal Units	-	-	92	92	246	346	377	1,153
Total asset replacement and renewal expenditure	**42,291**	**54,796**	**65,633**	**62,994**	**63,869**	**62,790**	**57,706**	**312,992**
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-	-	-
Total asset replacement and renewal less capital contributions	**42,291**	**54,796**	**65,633**	**62,994**	**63,869**	**62,790**	**57,706**	**312,992**
11 Asset relocations (net)	1,014	2,465	2,212	2,056	1,954	2,119	2,147	10,489
Total asset relocations expenditure	**1,014**	**2,465**	**2,212**	**2,056**	**1,954**	**2,119**	**2,147**	**10,489**
less Capital contributions funding asset relocations	244	1,669	1,378	1,220	1,143	1,222	1,238	6,200
Asset relocations less capital contributions	**770**	**796**	**834**	**837**	**811**	**897**	**910**	**4,288**
12 Future Networks	-	245	498	498	237	261	-	1,495
13 RSE	1,062	-	-	-	-	793	804	1,597
Total quality of supply expenditure	**1,062**	**245**	**498**	**498**	**237**	**1,054**	**804**	**3,092**
less Capital contributions funding quality of supply	-	-	-	-	-	-	-	-
Quality of supply less capital contributions	**1,062**	**245**	**498**	**498**	**237**	**1,054**	**804**	**3,092**
4e2 project rows	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Total legislative and regulatory expenditure	-	-	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory	-	-	-	-	-	-	-	-
Legislative and regulatory less capital contributions	-	-	-	-	-	-	-	-
4e3 project rows	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Total other reliability, safety and environment	-	-	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-	-	-
14 IT	3,979	1,273	3,043	915	945	681	692	6,277
15 Facilities	4,330	3,326	5,811	2,270	1,981	1,936	1,762	13,760
4f2 project rows	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
Total atypical non-network	-	-	-	-	-	-	-	-
Total capex non-network assets	**8,309**	**4,600**	**8,854**	**3,185**	**2,926**	**2,617**	**2,455**	**20,037**
Total capex network assets	**58,268**	**76,706**	**81,294**	**77,082**	**96,078**	**86,439**	**80,620**	**421,513**
Total capex network assets less capital contributions	**52,384**	**67,174**	**73,863**	**70,542**	**88,330**	**77,224**	**70,027**	**379,985**

CPP Financial Model, Supporting Model – Expenditure vProposal, Sch E table 4

Table 5: Capex by asset categories

Actual and forecast capex in constant prices $(000)

		Current period					Assessment Period		CPP Regulatory Period					Total CPP period
		CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
5a System Growth														
	Subtransmission lines	-	263	2	116	770	-	531	-	3,276	1,233	-	-	4,509
	Subtransmission cables	-	263	2	116	770	-	431	-	2,752	1,764	-	-	4,515
	Zone substations	7,083	6,997	24	5	5,173	3,367	1,395	891	972	3,737	1,559	32	7,190
	Distribution and LV lines	133	431	86	42	22	1,608	1,191	1,223	966	990	1,268	1,298	5,744
	Distribution and LV cables	46	965	111	404	1,169	1,176	872	895	707	724	928	950	4,203
	Distribution substations and transformers	36	178	-	155	109	510	378	388	306	314	402	412	1,821
	Distribution switchgear	42	246	3	364	182	569	421	433	342	350	448	459	2,032
	Other network assets	3	185	55	5,352	192	21	18	50	12	135	76	16	288
	System growth expenditure	**7,343**	**9,527**	**283**	**6,554**	**8,387**	**7,250**	**5,238**	**3,879**	**9,332**	**9,247**	**4,680**	**3,165**	**30,303**
Less	Capital contributions funding system growth	18	23	28	-	-	-	-	-	-	-	-	-	-
	System growth less capital contributions	**7,325**	**9,504**	**255**	**6,554**	**8,387**	**7,250**	**5,238**	**3,879**	**9,332**	**9,247**	**4,680**	**3,165**	**30,303**
5b Asset Replacement and Renewal														
	Subtransmission lines	334	60	1,376	2,000	2,348	939	6,770	6,622	7,875	958	398	408	16,262
	Subtransmission cables	334	60	1,376	2,000	2,348	2,703	553	423	2,296	3,156	3,096	4,468	13,440
	Zone substations	1,582	406	897	7,718	11,996	7,727	11,172	12,809	8,676	12,061	11,636	6,820	52,002
	Distribution and LV lines	4,494	4,038	5,362	33,083	19,581	19,510	22,196	26,303	29,367	29,231	25,145	23,818	133,864
	Distribution and LV cables	331	362	927	1,244	2,482	827	1,907	2,477	2,520	2,754	2,642	2,234	12,627
	Distribution substations and transformers	656	591	418	2,992	581	3,409	3,119	5,065	6,403	7,159	7,329	6,640	32,596
	Distribution switchgear	205	156	898	1,813	554	1,599	3,867	4,088	4,118	4,156	4,122	2,630	19,114
	Other network assets	48	173	7,772	1,601	735	-	191	290	172	506	481	418	1,867
	Total asset replacement and renewal expenditure	**7,985**	**5,847**	**19,026**	**52,453**	**40,624**	**36,713**	**49,776**	**58,078**	**61,426**	**59,982**	**54,849**	**47,436**	**281,771**
Less	Capital contributions funding asset replacement and renewal	-	28	27	-	22	-	-	-	-	-	-	-	-
	Total asset replacement and renewal less capital contributions	**7,985**	**5,819**	**18,999**	**52,453**	**40,602**	**36,713**	**49,776**	**58,078**	**61,426**	**59,982**	**54,849**	**47,436**	**281,771**

Actual and forecast capex in nominal prices $(000)

		Current period					Assessment Period		CPP Regulatory Period					Total CPP Period
		CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
5a System Growth														
	Subtransmission lines	-	248	2	112	758	-	545	-	3,517	1,359	-	-	4,876
	Subtransmission cables	-	248	2	112	758	-	442	-	2,951	1,941	-	-	4,892
	Zone substations	6,654	6,595	23	5	5,091	3,367	1,424	925	1,012	4,021	1,716	36	7,710
	Distribution and LV lines	125	406	82	41	21	1,608	1,221	1,280	1,035	1,087	1,422	1,487	6,312
	Distribution and LV cables	43	910	106	391	1,151	1,176	893	937	758	797	1,044	1,092	4,627
	Distribution substations and transformers	34	168	-	150	107	510	380	392	311	321	414	426	1,864
	Distribution switchgear	39	232	3	352	179	569	431	452	365	382	499	521	2,219
	Other network assets	3	174	52	5,180	189	21	19	52	13	148	86	18	317
	System growth expenditure	**6,898**	**8,980**	**270**	**6,343**	**8,255**	**7,250**	**5,355**	**4,038**	**9,961**	**10,058**	**5,180**	**3,580**	**32,818**
Less	Capital contributions funding system growth	17	22	27	-	-	-	-	-	-	-	-	-	-
	System growth less capital contributions	**6,881**	**8,958**	**243**	**6,343**	**8,255**	**7,250**	**5,355**	**4,038**	**9,961**	**10,058**	**5,180**	**3,580**	**32,818**
5b Asset Replacement and Renewal														
	Subtransmission lines	314	57	1,311	1,936	2,311	939	6,941	6,936	8,454	1,057	449	470	17,366
	Subtransmission cables	314	57	1,311	1,936	2,311	2,703	566	443	2,461	3,473	3,484	5,138	14,999
	Zone substations	1,486	383	855	7,470	11,807	7,727	11,392	13,265	9,137	12,900	12,598	7,567	55,467
	Distribution and LV lines	4,222	3,806	5,109	32,020	19,272	19,510	22,740	27,521	31,447	32,081	28,205	27,281	146,535
	Distribution and LV cables	311	341	883	1,204	2,443	827	1,954	2,591	2,696	3,020	2,959	2,554	13,820
	Distribution substations and transformers	616	557	398	2,896	572	3,409	3,147	5,137	6,563	7,400	7,630	6,976	33,706
	Distribution switchgear	193	147	856	1,755	545	1,599	3,914	4,188	4,272	4,368	4,380	2,846	20,054
	Other network assets	45	163	7,405	1,550	723	-	196	303	185	557	541	480	2,066
	Total asset replacement and renewal expenditure	**7,501**	**5,511**	**18,128**	**50,767**	**39,985**	**36,713**	**50,850**	**60,385**	**65,215**	**64,854**	**60,245**	**53,312**	**304,012**
Less	Capital contributions funding asset replacement and renewal	-	26	26	-	21	-	-	-	-	-	-	-	-
	Total asset replacement and renewal less capital contributions	**7,501**	**5,485**	**18,102**	**50,767**	**39,963**	**36,713**	**50,850**	**60,385**	**65,215**	**64,854**	**60,245**	**53,312**	**304,012**

Forecast commissioned asset values in nominal terms $(000)

		Assessment Period		CPP Regulatory Period					Total CPP Period
		CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
5a System Growth									
	Subtransmission lines	-	-	-	-	5,563	-	-	5,563
	Subtransmission cables	-	-	-	-	5,427	-	-	5,427
	Zone substations	64	4,607	33	26	5,082	2,939	38	8,117
	Distribution and LV lines	1,475	1,238	1,333	1,058	1,053	1,491	1,550	6,485
	Distribution and LV cables	1,079	906	976	775	772	1,094	1,138	4,754
	Distribution substations and transformers	468	385	408	318	311	434	444	1,915
	Distribution switchgear	522	437	471	373	370	523	543	2,280
	Other network assets	19	15	16	13	144	136	19	328
	System growth expenditure	**3,626**	**7,589**	**3,237**	**2,562**	**18,722**	**6,617**	**3,731**	**34,869**
Less	Capital contributions funding system growth	-	-	-	-	-	-	-	-
	System growth less capital contributions	**3,626**	**7,589**	**3,237**	**2,562**	**18,722**	**6,617**	**3,731**	**34,869**
5b Asset Replacement and Renewal									
	Subtransmission lines	992	7,039	7,225	8,642	1,023	471	490	17,850
	Subtransmission cables	-	6,788	517	328	5,513	359	8,568	15,285
	Zone substations	7,088	7,815	16,224	8,091	11,503	15,854	6,842	58,513
	Distribution and LV lines	21,023	24,080	28,666	32,146	31,063	29,569	28,430	149,873
	Distribution and LV cables	759	1,920	2,761	2,695	2,868	3,201	2,650	14,175
	Distribution substations and transformers	3,127	3,146	5,396	6,681	7,126	8,056	7,284	34,544
	Distribution switchgear	1,466	3,900	4,433	4,319	4,209	4,664	2,966	20,592
	Other network assets	7,836	107	410	92	564	616	477	2,158
	Total asset replacement and renewal expenditure	**42,291**	**54,796**	**65,633**	**62,994**	**63,869**	**62,790**	**57,706**	**312,992**
Less	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-	-	-
	Total asset replacement and renewal less capital contributions	**42,291**	**54,796**	**65,633**	**62,994**	**63,869**	**62,790**	**57,706**	**312,992**

Table 6: Opex projects and programmes

Adjust the column widths as required

Actual and forecast opex in constant prices $(000)

	Project reference	Project/programme name	Current period					Assessment Period		CPP Regulatory Period					Total CPP Period
			CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
6a	Service interruptions and emergencies														
		18 Reactive Maintenance	4,380	4,408	5,912	4,392	4,874	3,951	4,683	4,645	4,621	4,557	4,507	4,426	22,755
		Total Service interruptions and emergencies	**4,380**	**4,408**	**5,912**	**4,392**	**4,874**	**3,951**	**4,683**	**4,645**	**4,621**	**4,557**	**4,507**	**4,426**	**22,755**
6b:	Vegetation management														
		19 Vegetation	3,852	5,567	3,882	5,700	5,755	5,580	5,301	5,401	5,008	3,670	3,600	3,507	21,186
		Total Vegetation management	**3,852**	**5,567**	**3,882**	**5,700**	**5,755**	**5,580**	**5,301**	**5,401**	**5,008**	**3,670**	**3,600**	**3,507**	**21,186**
6c	Routine and corrective maintenance and inspection														
		16 Preventive Maintenance	3,499	4,527	5,009	4,718	4,544	4,907	5,619	6,500	5,998	6,459	5,604	5,970	30,531
		17 Corrective Maintenance	800	888	1,739	1,257	1,486	2,669	3,217	3,760	3,730	3,368	3,282	2,919	17,059
		Total Routine and corrective maintenance and inspection	**4,299**	**5,415**	**6,749**	**5,975**	**6,030**	**7,576**	**8,835**	**10,260**	**9,728**	**9,827**	**8,886**	**8,890**	**47,591**
6d	Asset replacement and renewal														
		17 Corrective Maintenance	620	948	293	657	358	-	-	-	-	-	-	-	-
		Total Asset replacement and renewal	**620**	**948**	**293**	**657**	**358**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
		Total network opex	**13,152**	**16,338**	**16,836**	**16,724**	**17,016**	**17,106**	**18,819**	**20,306**	**19,357**	**18,053**	**16,992**	**16,823**	**91,532**

Actual and forecast opex in nominal prices (($000)

	Project reference	Project/programme name	Current period					Assessment Period		CPP Regulatory Period					Total CPP Period
			CY-4	CY-3	CY-2	CY-1	CY0	CA	CA+1	Year 1	Year 2	Year 3	Year 4	Year 5	
6a	Service interruptions and emergencies														
		18 Reactive Maintenance	4,115	4,155	5,633	4,251	4,797	3,951	4,805	4,870	4,962	5,016	5,068	5,080	24,996
		Total Service interruptions and emergencies	**4,115**	**4,155**	**5,633**	**4,251**	**4,797**	**3,951**	**4,805**	**4,870**	**4,962**	**5,016**	**5,068**	**5,080**	**24,996**
6b:	Vegetation management														
		19 Vegetation	3,619	5,247	3,699	5,517	5,664	5,580	5,440	5,663	5,377	4,040	4,048	4,025	23,153
		Total Vegetation management	**3,619**	**5,247**	**3,699**	**5,517**	**5,664**	**5,580**	**5,440**	**5,663**	**5,377**	**4,040**	**4,048**	**4,025**	**23,153**
6c	Routine and corrective maintenance and inspection														
		16 Preventive Maintenance	3,287	4,267	4,773	4,566	4,473	4,907	5,770	6,824	6,451	7,119	6,312	6,865	33,571
		17 Corrective Maintenance	752	837	1,657	1,217	1,462	2,669	3,303	3,948	4,012	3,712	3,696	3,357	18,725
		Total Routine and corrective maintenance and inspection	**4,039**	**5,104**	**6,430**	**5,783**	**5,935**	**7,576**	**9,073**	**10,772**	**10,463**	**10,831**	**10,008**	**10,222**	**52,296**
6d	Asset replacement and renewal														
		17 Corrective Maintenance	582	894	279	636	352	-	-	-	-	-	-	-	-
		Total Asset replacement and renewal	**582**	**894**	**279**	**636**	**352**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
		Total network opex	**12,355**	**15,400**	**16,041**	**16,187**	**16,748**	**17,106**	**19,319**	**21,306**	**20,802**	**19,887**	**19,124**	**19,327**	**100,445**

Table 7: Non-network opex

Actual and forecast opex in constant prices $(000)

	Project reference	Project/programme name	Current period CY-4	CY-3	CY-2	CY-1	CY0	Assessment Period CA	CA+1	CPP Regulatory Period Year 1	Year 2	Year 3	Year 4	Year 5	Total CPP Period
7a	System operations and network support														
		20 SONS	4,106	3,971	4,058	11,037	13,038	15,037	15,744	15,324	16,564	15,664	15,578	15,103	78,233
		25 Upper Clutha DER Solution	-	-	-	-	-	-	-	265	594	582	699	862	3,001
		Total System operations and network support	**4,106**	**3,971**	**4,058**	**11,037**	**13,038**	**15,037**	**15,744**	**15,589**	**17,158**	**16,245**	**16,277**	**15,966**	**81,235**
7b	Business support														
		21 People Costs	523	163	160	3,675	7,660	9,761	8,446	7,731	8,820	8,106	7,807	7,828	40,293
		22 IT Opex	-	57	863	870	1,657	2,349	3,065	3,465	3,304	3,477	3,418	3,367	17,032
		23 Premises and Plant	619	561	732	781	753	148	242	288	307	310	515	534	1,955
		24 Administration and Governance	4,787	5,603	6,164	4,395	3,307	3,041	3,054	3,032	3,134	3,141	3,114	3,139	15,560
		Total Business support	**5,928**	**6,384**	**7,919**	**9,720**	**13,377**	**15,299**	**14,807**	**14,517**	**15,566**	**15,035**	**14,854**	**14,868**	**74,839**
		Total non network opex	**10,034**	**10,356**	**11,977**	**20,757**	**26,415**	**30,337**	**30,551**	**30,106**	**32,723**	**31,280**	**31,132**	**30,833**	**156,074**

Actual and forecast opex in nominal prices $(000)

	Project reference	Project/programme name	Current period CY-4	CY-3	CY-2	CY-1	CY0	Assessment Period CA	CA+1	CPP Regulatory Period Year 1	Year 2	Year 3	Year 4	Year 5	Total CPP Period
7a	System operations and network support														
		20 SONS	3,857	3,743	3,867	10,682	12,833	15,037	16,129	16,014	17,721	17,195	17,461	17,262	85,653
		25 Upper Clutha DER Solution						-	-	277	635	639	784	986	3,320
		Total System operations and network support	**3,857**	**3,743**	**3,867**	**10,682**	**12,833**	**15,037**	**16,129**	**16,291**	**18,356**	**17,834**	**18,245**	**18,248**	**88,973**
7b	Business support														
		21 People Costs	491	154	152	3,557	7,539	9,761	8,655	8,083	9,441	8,901	8,753	8,949	44,128
		22 IT Opex	-	53	822	842	1,631	2,349	3,141	3,623	3,537	3,819	3,832	3,849	18,660
		23 Premises and Plant	582	529	698	756	742	148	250	305	333	345	586	621	2,190
		24 Administration and Governance	4,497	5,281	5,873	4,254	3,255	3,041	3,150	3,211	3,403	3,488	3,538	3,651	17,290
		Total Business support	**5,569**	**6,018**	**7,545**	**9,408**	**13,166**	**15,299**	**15,195**	**15,222**	**16,714**	**16,552**	**16,709**	**17,071**	**82,268**
		Total non network opex	**9,426**	**9,761**	**11,412**	**20,090**	**25,999**	**30,337**	**31,324**	**31,512**	**35,070**	**34,386**	**34,954**	**35,318**	**171,241**

Table 8: Aggregate forecast commissioned assets by asset categories

Applicant may disaggregate other assets by asset types

Forecast amounts should be net after adjustments for any capital contributions and related party transactions.

Asset category	Forecast commissioned asset values in nominal terms $(000)							
	Assessment Period		CPP Regulatory Period					*Total CPP Period*
	CA	*CA+1*	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*	
Subtransmission lines	1,042	7,090	7,279	8,696	6,640	530	551	23,695
Subtransmission cables	46	6,830	559	371	10,989	417	8,632	20,968
Zone substations	7,269	12,517	16,349	8,209	16,703	18,940	7,052	67,253
Distribution and LV lines	23,024	25,791	30,478	33,684	32,667	31,721	30,721	159,271
Distribution and LV cables	3,965	4,641	5,547	5,289	5,867	7,042	6,959	30,704
Distribution substations and transformers	5,349	4,945	7,175	8,352	9,144	10,598	10,169	45,437
Distribution switchgear	3,829	4,990	5,549	5,336	5,373	6,959	5,443	28,659
Other network assets	7,859	370	926	606	947	1,017	500	3,997
Non-network assets	8,309	4,600	8,854	3,185	2,926	2,617	2,455	20,037
Total forecast commissioned assets	**60,693**	**71,774**	**82,718**	**73,727**	**91,256**	**79,840**	**72,481**	**400,022**

Table 9: Cost escalation factors

Supplier must provide inflation and other factors used to convert real prices into nominal prices.

Supplier may modify this table to suit its processes

Escalator name and description	Current Period					Assessment Period		CPP Regulatory Period				
	CY-4	*CY-3*	*CY-2*	*CY-1*	*CY0*	*CA*	*CA+1*	*Year 1*	*Year 2*	*Year 3*	*Year 4*	*Year 5*
Historical capital expenditure												
CPI series	-	0.33%	1.08%	1.58%	1.69%							
Forecast capital expenditure												
Labour						2.11%	2.59%	2.14%	2.54%	2.81%	2.26%	2.13%
Cables						(0.34%)	2.22%	2.18%	2.23%	2.18%	2.24%	2.31%
Conductor						(0.42%)	2.27%	2.22%	2.28%	2.23%	2.29%	2.36%
Transformers						0.48%	0.10%	0.08%	0.07%	0.11%	0.04%	0.12%
Switchgear						0.72%	0.61%	0.60%	0.61%	0.62%	0.58%	0.65%
Other						2.62%	2.27%	2.07%	1.97%	1.92%	1.87%	2.00%
Historical operating expenditure												
CPI series	-	0.33%	1.08%	1.58%	1.69%							
Forecast operating expenditure												
LCI - All sectors						2.52%	2.40%	1.96%	2.36%	2.62%	2.08%	1.93%
LCI - Electricity, gas, and water						2.03%	2.47%	2.03%	2.43%	2.69%	2.14%	2.00%
LCI - Professional and technical						2.11%	2.46%	2.02%	2.42%	2.68%	2.14%	1.99%
PPI - Inputs						2.93%	3.13%	2.66%	2.56%	2.27%	2.34%	2.35%
PPI-O Heavy and civil engineering						3.77%	3.93%	3.46%	3.36%	3.07%	3.14%	3.15%
PPI-O Professional services						2.84%	2.82%	2.35%	2.25%	1.96%	2.04%	2.04%

Aurora ENERGY

Table 10: Network demand forecasts

Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Current period					Assessment Period		CPP Regulatory Period				
	CY-4 2015	CY-3 2016	CY-2 2017	CY-1 2018	CY0 2019	CA 2020	CA+1 2021	Year 1 2022	Year 2 2023	Year 3 2024	Year 4 2025	Year 5 2026
Residential	878	673	1,165	1,208	971	965	754	629	461	629	587	963
Load Group 0	(10)	(17)	(13)	(5)	(7)	-1	3	2	2	2	2	4
Load Group 0A	52	82	132	21	41	-27	7	6	4	6	6	9
Load Group 1A	16	30	14	15	26	17	9	7	5	7	7	11
Load Group 1	126	(16)	14	64	(22)	44	57	48	35	48	44	73
Load Group 2	104	73	71	144	166	150	65	54	40	54	50	83
Load Group 3	2	11	7	-	4	-1	2	2	1	2	2	3
Load Group 3A	6	8		8	(6)	7	2	1	1	1	1	2
Load Group 4	7		6	7	6	2	1	1	1	1	1	2
Load Group 5	(1)	1		-	-	1	-	-	-	-	-	-
Street Lighting	2			-	-	0	-	-	-	-	-	-
Distributed Unmetered Load (excl Street Lighting				-	-	-	-	-	-	-	-	-
Total number of connections	1,182	845	1,396	1,462	1,179	1,157	900	750	550	750	700	1,150

**include additional rows if needed*

Distributed generation

	CY-4 2015	CY-3 2016	CY-2 2017	CY-1 2018	CY0 2019	CA 2020	CA+1 2021	Year 1 2022	Year 2 2023	Year 3 2024	Year 4 2025	Year 5 2026
Number of connected generator units > 10 MW	1	1	1	1	1	1	1	1	1	1	1	1
Total capacity of all distributed generation (MVA)	125.51	127.70	128.90	129.74	130.83	139.68	140.46	141.22	141.98	142.74	143.50	144.27

System Demand

		CY-4 2015	CY-3 2016	CY-2 2017	CY-1 2018	CY0 2019	CA 2020	CA+1 2021	Year 1 2022	Year 2 2023	Year 3 2024	Year 4 2025	Year 5 2026
	Maximum coincident system demand (MW)												
	GXP demand	225	248	229	222	243	227	229	231	233	236	238	240
plus	Distributed generation output at HV and above	61	43	62	77	56	56	57	57	58	59	59	60
	Maximum system coincident peak demand	286	291	291	300	299	283	286	289	292	294	297	300
less	Net transfers to (from) other EDBs at HV and above	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Demand on system for supply to consumers' connection points	286	290	291	300	299	283	286	289	291	294	297	300

Electricity volumes carried (GWh)

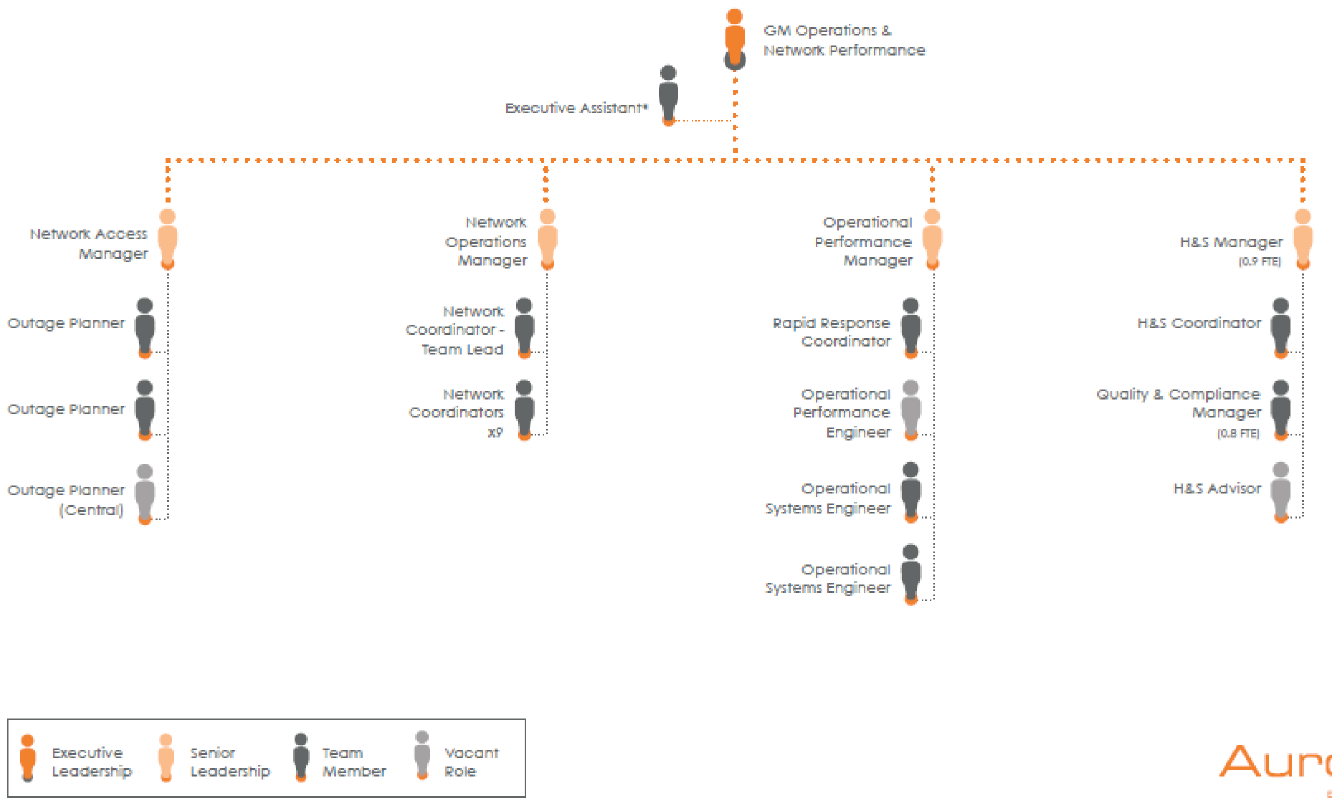
		CY-4 2015	CY-3 2016	CY-2 2017	CY-1 2018	CY0 2019	CA 2020	CA+1 2021	Year 1 2022	Year 2 2023	Year 3 2024	Year 4 2025	Year 5 2026
	Electricity supplied from GXPs	1,069	1,101	1,077	1,121	1,267	1,293	1,300	1,306	1,313	1,319	1,326	1,333
less	Electricity exports to GXPs	47	36	46	37	43	64	64	64	64	65	65	65
plus	Electricity supplied from distributed generation	324	323	332	316	196	202	202	203	204	205	206	207
less	Net electricity supplied to (from) other EDBs	(1)	(1)	(1)	(1)	(1)	0	(0)	(0)	(0)	(0)	(0)	(0)
	Electricity entering system for supply to ICPs	1,347	1,388	1,364	1,400	1,420	1,431	1,438	1,445	1,452	1,460	1,467	1,474
less	Total energy delivered to ICPs	1,248	1,303	1,284	1,308	1,333	1,342	1,349	1,356	1,362	1,369	1,376	1,383

Appendix P. Organisational Charts

978. This appendix provides details of Aurora Energy's organisations structure. We have no planned changes to our organisational structure during the next period, other than the secondments to the 12 Month Programme Team (Works Planning & Delivery), returning to their home division(Technology & Information).

OPERATIONS AND NETWORK PERFORMANCE
ORGANISATIONAL STRUCTURE

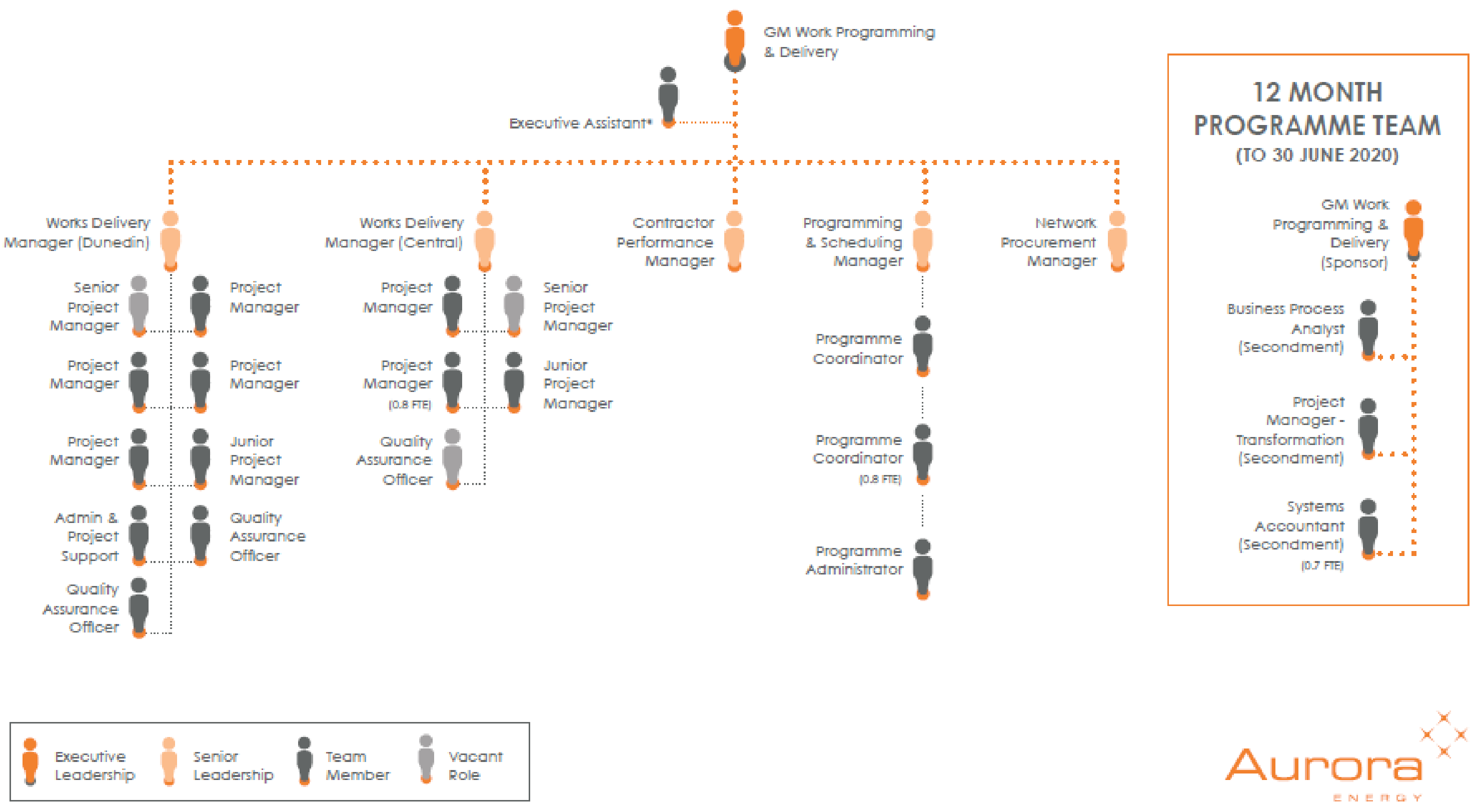
	HEADCOUNT	FTE
FILLED	22	21.7
VACANT	3	3
TOTAL	25	24.7



* Executive Assistant included in Corporate's Headcount

WORK PROGRAMMING AND DELIVERY
ORGANISATIONAL STRUCTURE

	HEADCOUNT	FTE
FILLED	23	22.3
VACANT	3	3
TOTAL	26	25.3

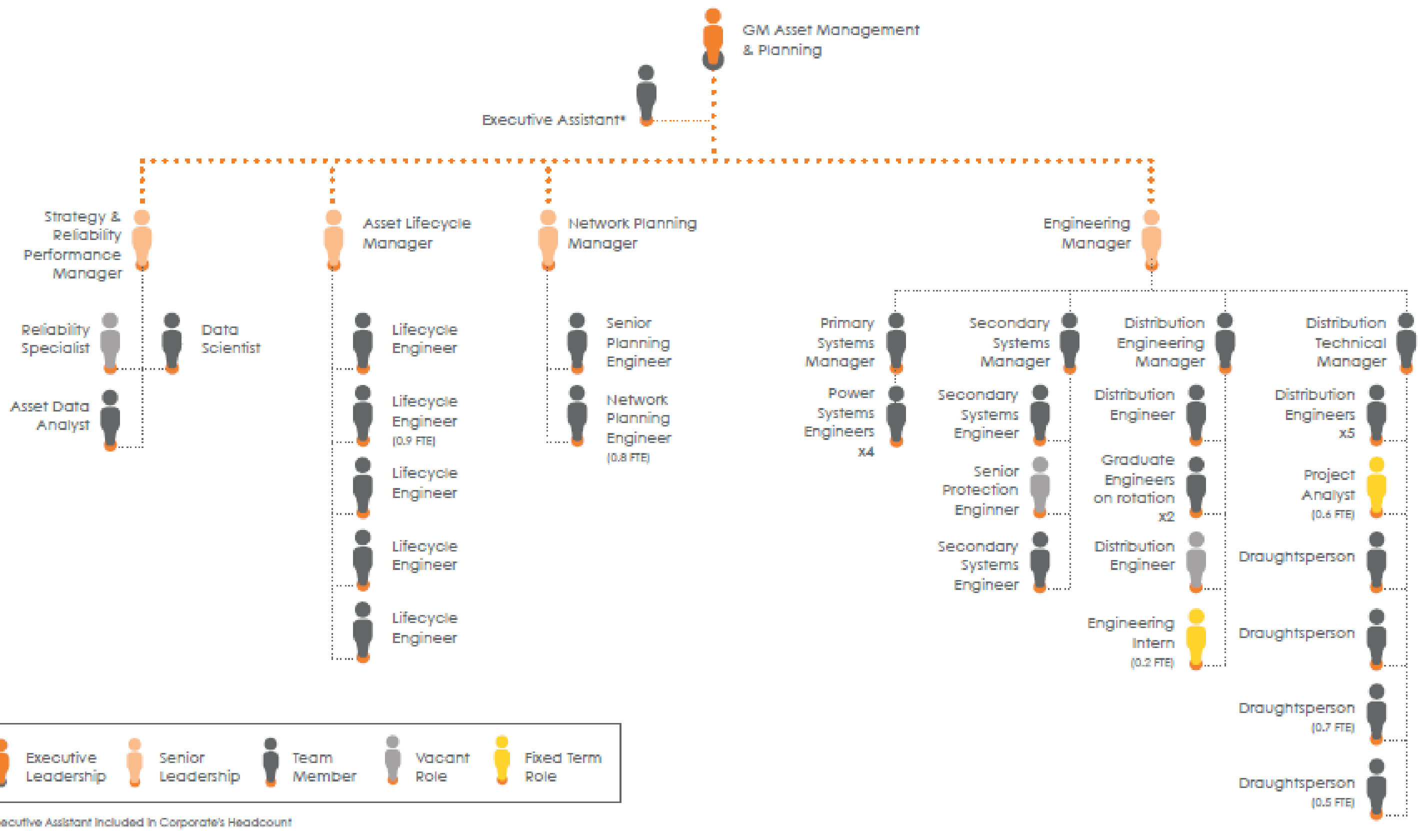


* Executive Assistant included in Corporate's Headcount

ASSET MANAGEMENT AND PLANNING

ORGANISATIONAL STRUCTURE

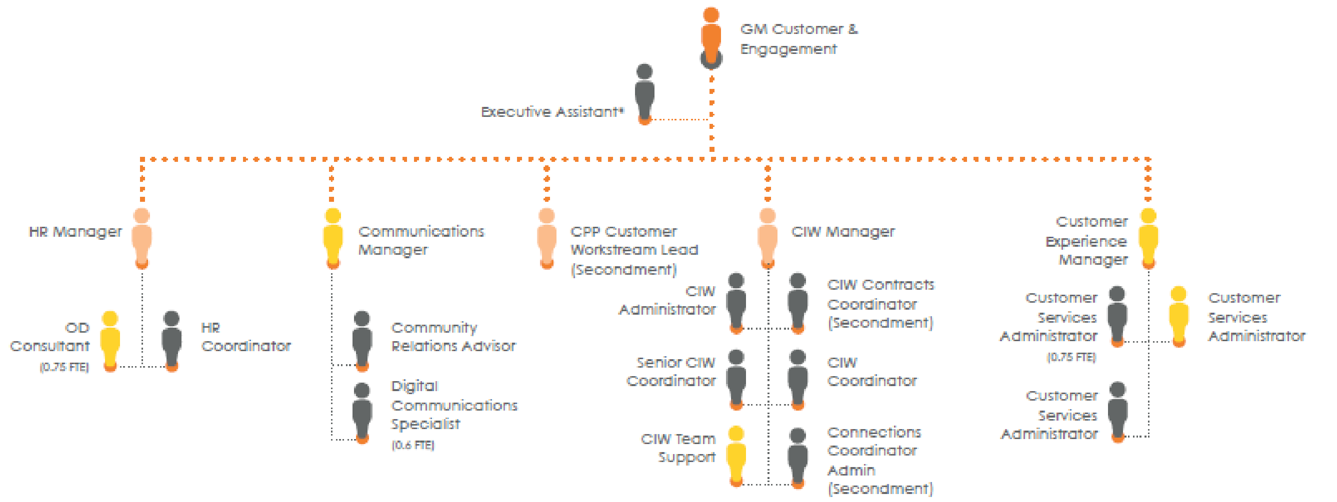
	HEADCOUNT	FTE
FILLED	38	35.7
VACANT	3	3
TOTAL	41	38.7



* Executive Assistant included in Corporate's Headcount

CUSTOMER AND ENGAGEMENT
ORGANISATIONAL STRUCTURE

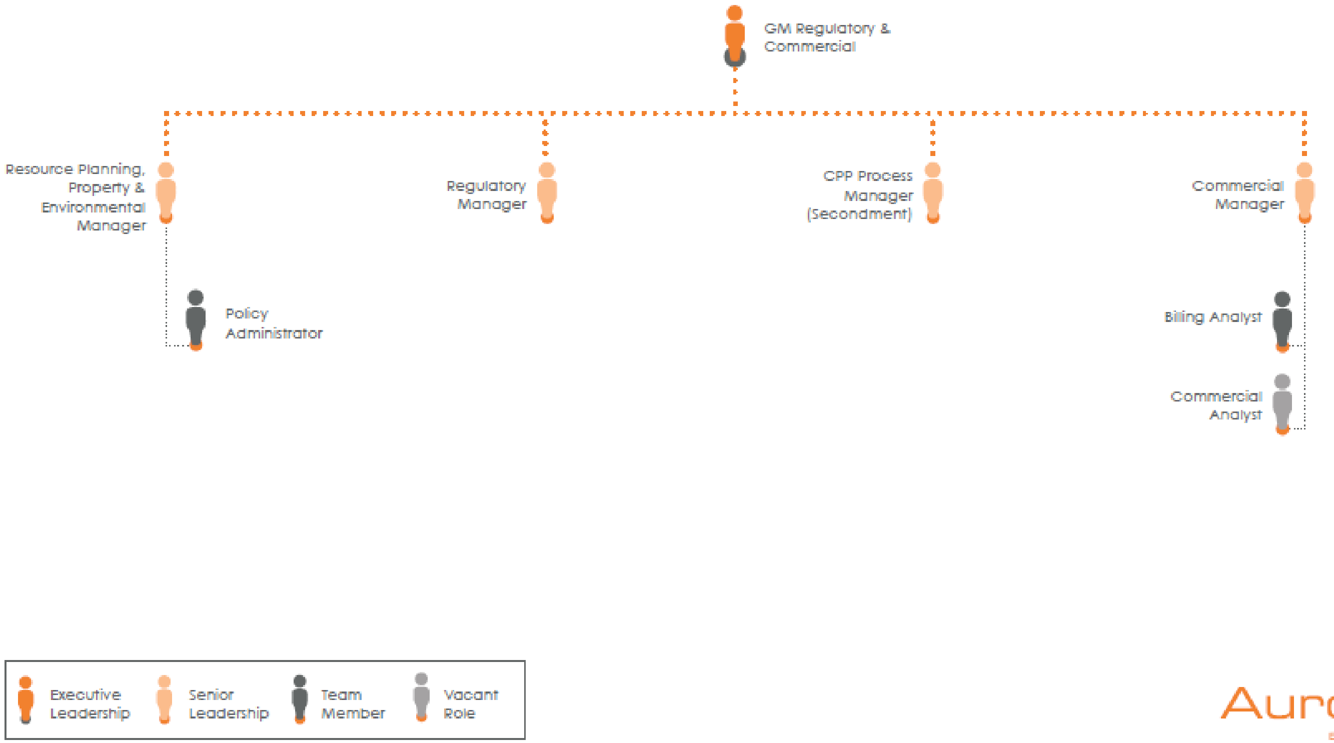
	HEADCOUNT	FTE
FILLED	19	18.1
VACANT	0	0
TOTAL	19	18.1



* Executive Assistant included in Corporate's Headcount

REGULATORY AND COMMERCIAL
ORGANISATIONAL STRUCTURE

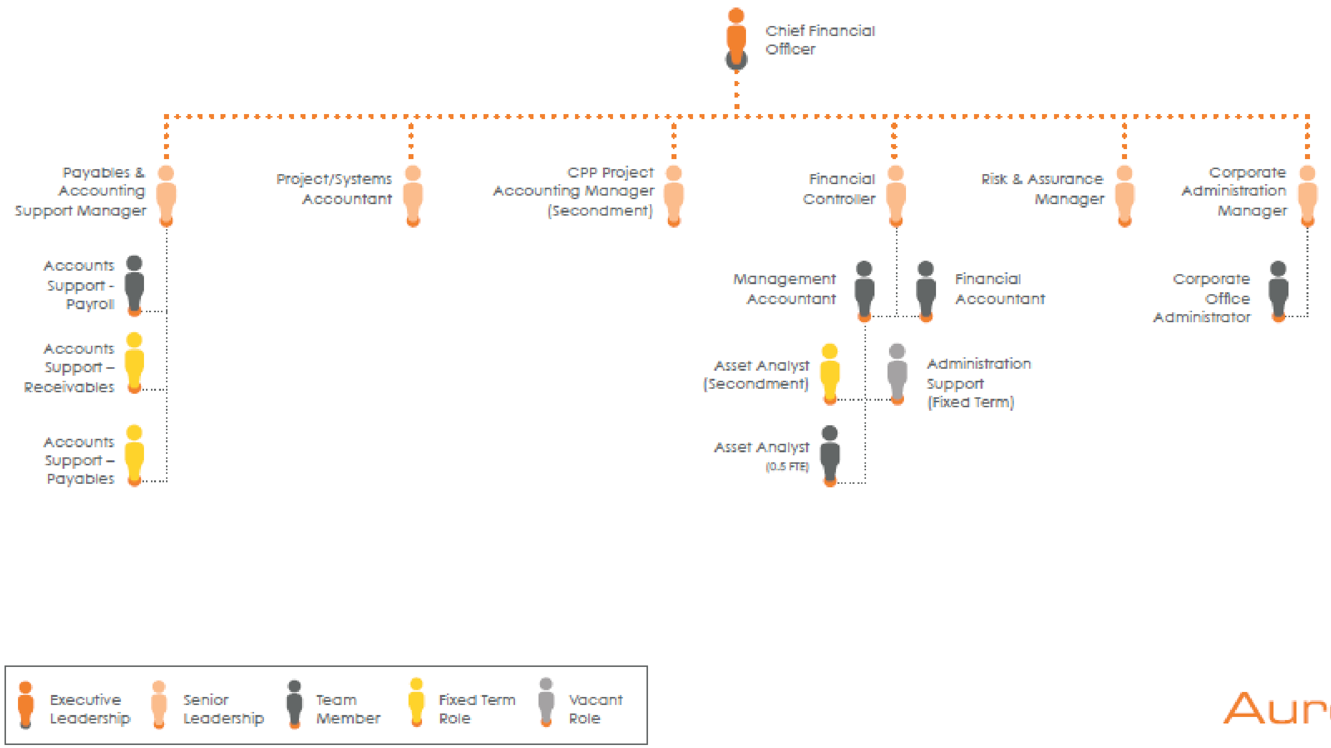
	HEADCOUNT	FTE
FILLED	7	7
VACANT	1	1
TOTAL	8	8



ACCOUNTING, FINANCE AND RISK ASSURANCE

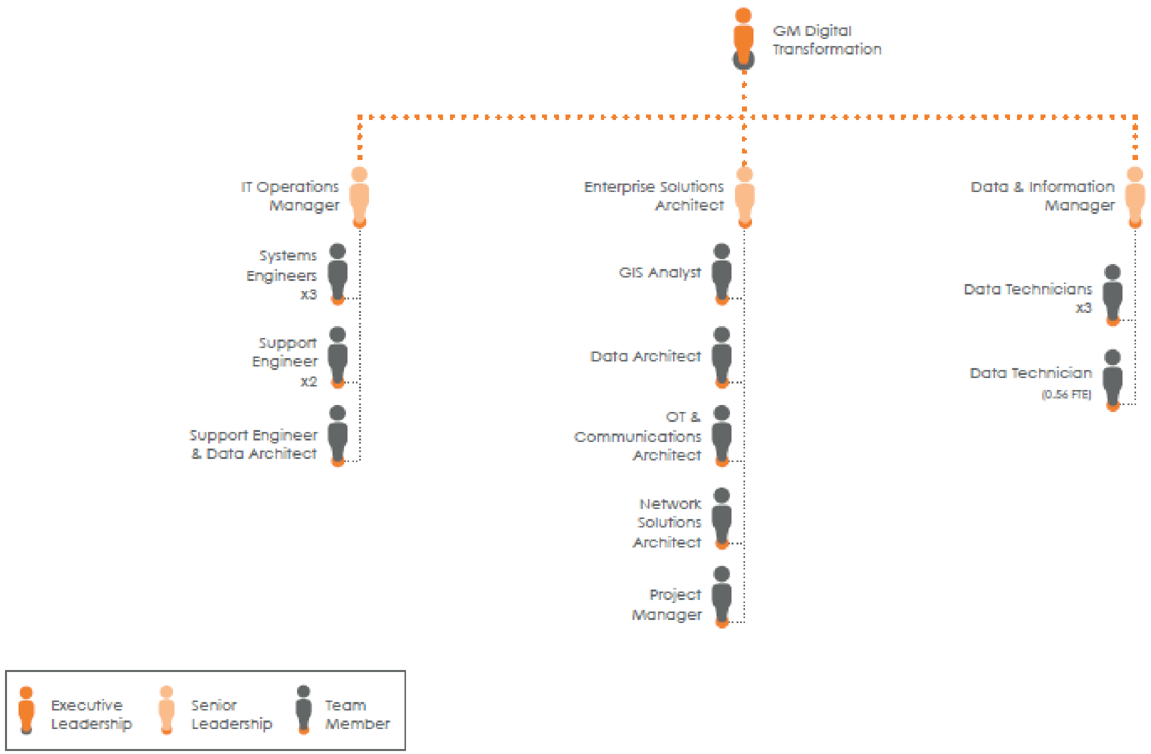
ORGANISATIONAL STRUCTURE

	HEADCOUNT	FTE
FILLED	15	14.5
VACANT	1	1
TOTAL	16	15.5



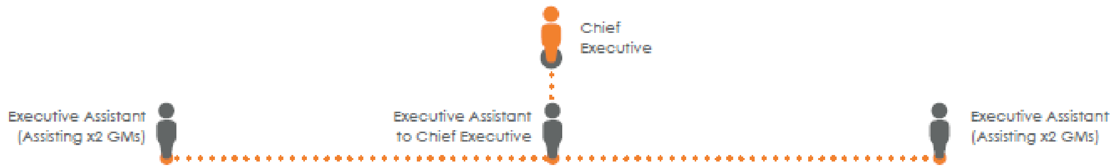
TECHNOLOGY AND INFORMATION
ORGANISATIONAL STRUCTURE

	HEADCOUNT	FTE
FILLED	19	18.56
VACANT	0	0
TOTAL	19	18.56



CORPORATE
ORGANISATIONAL STRUCTURE

	HEADCOUNT	FTE
FILLED	4	4
VACANT	0	0
TOTAL	4	4



Appendix Q. Independent Auditors Report

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Auditor's Report

To the Board of Directors of Aurora Energy Limited

The Auditor-General is the auditor of Aurora Energy Limited (Aurora Energy). The Auditor-General has appointed me, Julian Tan, using the staff and resources of Audit New Zealand, to provide an assurance opinion, on his behalf, on the extent to which the Customised Price-Quality Path Proposal prepared by Aurora Energy and dated 12 June 2020 (the CPP Proposal) complies with the Electricity Distribution Services Input Methodologies Determination 2012 consolidating all amendments as of 20 May 2020 (the Determination).

Responsibilities of the Board of Directors for the preparation of the CPP Proposal

The Board of Directors of Aurora Energy is responsible for the preparation of the CPP Proposal in accordance with the Determination, and for such internal control as is necessary to enable the preparation of the CPP Proposal that is free from material misstatement. In particular, Part 5, Subpart 5.5.4 of the Determination states that the Board of Directors is responsible for ensuring that the information contained in the CPP Proposal has been derived and is provided in accordance with the Determination and properly reflects Aurora Energy's operations and events which occurred during the current period, and that the assumptions made in respect of the forecast information for the next period in the CPP Proposal are relevant and reasonable.

Responsibilities of the Auditor for the audit of the CPP Proposal

General responsibilities

Our responsibility is to express an opinion on the CPP Proposal, as required by clauses 5.1.4 and 5.5.3 of the Determination. We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised): *Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, and Standard on Assurance Engagements 3100 (Revised): *Assurance Engagements on Compliance*, issued by the New Zealand Auditing and Assurance Standards Board.

In addition, our responsibility to express an opinion on whether the quantitative forecast information provided in spreadsheets has been properly compiled on the basis of relevant and reasonable disclosed assumptions was carried out with regard to the International Standard on Assurance Engagements 3400: *The Examination of Prospective Financial Information* issued by the International Auditing and Assurance Standards Board.

Reasonable assurance

Our engagement was designed to provide reasonable assurance in respect of:

- proper record keeping (clause 5.5.3(1)(a) of the Determination);
- actual financial information relating to the current period (clause 5.5.3(1)(b) of the Determination);
- forecast financial information relating to the next period (clause 5.5.3(1)(c) of the Determination);
- quantitative historical information provided in spreadsheets (clause 5.5.3(1)(d) of the Determination); and
- the matters over which an opinion is required under clauses 5.5.3(2)(a) and 5.5.3(2)(b) of the Determination.

A reasonable assurance engagement involves performing procedures to obtain a high level of assurance about the matters on which we are required to form an opinion. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the CPP Proposal, whether due to fraud, error, or non-compliance with the Determination. In making those risk assessments, the auditor considers internal control relevant to Aurora Energy's preparation of the CPP Proposal in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Aurora Energy's internal control.

Limited assurance

Our engagement was designed to provide limited assurance in respect of whether the quantitative forecast information provided in spreadsheets has been properly compiled on the basis of relevant and reasonable disclosed assumptions (clause 5.5.3(1)(e) of the Determination).

A limited assurance engagement is substantially less in scope, and provides less assurance, than a reasonable assurance engagement in relation to both the risk assessment procedures, including an understanding of internal control, and the procedures performed in response to the assessed risks.

The procedures we performed were based on our professional judgement and included making enquiries primarily of the Board of Directors and personnel of Aurora Energy, and applying analytical and other review procedures. Based on these enquiries and procedures we determined whether anything has come to our attention to suggest that the quantitative forecast information provided in spreadsheets has not been properly compiled on the basis of relevant and reasonable disclosed assumptions.

Generally accepted international practice, as prescribed by the International Standard on Assurance Engagements 3400: *The Examination of Prospective Financial Information,* is that auditors do not provide reasonable assurance on matters relating to future periods, and particularly on whether the disclosed assumptions are relevant and reasonable, as anticipated events frequently do not occur as expected and the variation could be material.

Our examination of Aurora Energy's records

For the purpose of forming our opinion as to whether, as far as appears from an examination of them, proper records have been kept to enable the complete and accurate compilation of information required by Subpart 4 of the Determination, we carried out the following work:

- Our work on the records underlying historical information was limited to assessing the design of Aurora Energy's systems, processes, procedures and records and in carrying out limited tests to assess whether Aurora Energy's systems, processes and procedures were operating as intended.

- Our work on the records underlying forecast information was limited to assessing whether adequate documentation had been retained that records the assumptions underlying the forecasts and that shows how the assumptions had been applied to produce forecast financial information for the next period and quantitative forecast information provided in spreadsheets in accordance with the Determination.

Actual historical information for the current period, quantitative historical information provided in spreadsheets, and forecast financial information for the next period

We planned and performed our work to obtain all the information and explanations we considered necessary in order to obtain reasonable assurance that the actual financial information relating to the current period, quantitative historical information provided in spreadsheets, and forecast financial information for the next period has been properly compiled in all material respects in accordance with the Determination.

The work we completed in respect of the actual financial information relating to the current period, and the quantitative historical information provided in spreadsheets was as follows:

- Work in respect of amounts and disclosures that were previously verified as part of the assurance engagements covering the information disclosure under the Electricity Distribution Information Disclosure Determination 2012 was limited to:
  - agreeing the amounts and disclosures to the underlying records, and, where possible, to the relevant Electricity Distribution Information Disclosure of Aurora Energy; and
  - checking that the information presented has been prepared in accordance with the Determination, in all material respects.
- Work in respect of amounts and disclosures that were not verified as part of the Electricity Distribution Information Disclosure Determination 2012 information disclosure included:

- examining reconciliations or other evidence to check that these amounts and disclosures were consistent with the Electricity Distribution Information Disclosure Determination 2012 information disclosure and the underlying records; and
- checking that the information presented has been prepared in accordance with the Determination in all material respects.

The work completed in respect of the forecast financial information for the next period involved checking that the information presented has been prepared in accordance with the Determination in all material respects. For detailed inputs into the models this involved testing compliance on a sample basis. Actual results are likely to be different from the forecast financial information since anticipated events frequently do not occur as expected and the variation could be material. Accordingly, we express no opinion as to whether results consistent with the forecast financial information will be achieved.

We have obtained all information and explanations that we required to provide a basis for our opinion.

Quantitative forecast information provided in spreadsheets

We are required to form an opinion as to whether the quantitative forecast information provided in spreadsheets has been properly compiled on the basis of relevant and reasonable disclosed assumptions. Forming an opinion on whether the disclosed assumptions are relevant and reasonable is also part of the role of the verifier, engaged by Aurora Energy in accordance with clause 5.5.2(2) of the Determination. We provide limited assurance on this matter in accordance with the appropriate standard being International Standard on Assurance Engagements 3400: *The Examination of Prospective Financial Information*.

Actual results are likely to be different from the quantitative forecast information provided in spreadsheets since anticipated events frequently do not occur as expected and the variation could be material. Accordingly, we express no opinion as to whether results consistent with the quantitative forecast information provided in spreadsheets will be achieved.

We have obtained all information and explanations that we required to provide a basis for our opinion.

Inherent limitations

Because of the inherent limitations in evidence gathering procedures, it is possible that fraud, error, or non-compliance with the Determination may occur and not be detected. As the procedures performed in respect of Aurora Energy's compliance with the Determination are undertaken on a test basis and the procedures performed in relation to the matters on which we provide reasonable assurance are not performed continuously throughout the year, our engagement cannot be relied on to detect all instances where Aurora Energy may not have complied with the Determination.

In addition, our examination of the quantitative forecast information provided in spreadsheets, on which we provide limited assurance, is not designed to detect all instances of non-compliance with the

Determination. Our examination generally involved making enquiries, primarily of the Board of Directors and personnel of Aurora Energy, and applying analytical and other review procedures.

The opinions expressed in this report have been formed on the basis outlined above.

Use of this report

This report has been prepared solely for your use and solely for the purpose of preparing and presenting the CPP Proposal. We understand that a copy of our report has been requested by the Commerce Commission solely for the purpose of assessing the CPP Proposal. We agree that a copy of our report may be provided to the Commerce Commission.

This report is not to be used for any other purpose, provided to any other person, or referred to in whole or in part without our prior written consent. We disclaim any assumption of responsibility for any reliance on this report to any persons or users other than you, or for any purpose other than that for which it was prepared.

Independence and quality control

When carrying out the engagement, we complied with the Auditor-General's:

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

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended): *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* issued by the New Zealand Auditing and Assurance Standards Board.

We also complied with the independent auditor requirements specified in the Determination.

In addition to this engagement, we have also performed and reported on the following legally required audit and assurance engagements for Aurora Energy:

- the annual audit of the financial statements and statement of service performance prepared under the Energy Companies Act 1992;

- the compliance statement prepared under the Electricity Distribution Services Default Price-Quality Path Determination 2015; and

- the information disclosure prepared under the Electricity Distribution Information Disclosure Determination 2012.

Other than this engagement and the engagements noted above, we have no relationship with, or interests in, Aurora Energy.

Our opinions

Our opinions have been formed on the basis of, and subject to, the limitations described under the *Responsibilities of the Auditor for the audit of the CPP Proposal* and *Inherent limitations* headings in this independent auditor's report.

In our opinion, as far as appears from an examination of them Aurora Energy has kept proper records to enable the complete and accurate compilation of information required by Part 5, Subpart 4 of the Determination.

In our opinion:

- the actual financial information relating to the current period included in the CPP Proposal has been prepared in all material respects in accordance with the Determination;
- the forecast financial information relating to the next period included in the CPP Proposal has been compiled in all material respects in accordance with the input methodologies as set out in the Determination;
- the quantitative historical information provided in spreadsheets included in the CPP Proposal has been properly compiled on the basis of the underlying source information;
- nothing has come to our attention to suggest that the quantitative forecast information provided in spreadsheets included in the CPP Proposal has not been properly compiled on the basis of relevant and reasonable disclosed assumptions;
- in respect of the operating costs not directly attributable, the operating expenditure forecast has been provided by Aurora Energy as specified in clause 5.3.5; and
- in respect of the regulated service asset values not directly attributable, the forecast value of commissioned assets has been provided by Aurora Energy in accordance with clause 5.3.6(3)(b) and as specified in clause 5.3.11(2)(b).

Our engagement was completed on 12 June 2020 and our opinion is expressed as at that date.

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

Appendix R. APPROVAL OF M&E REQUESTS

979. This appendix documents the Commission's approval of IM modifications and exemption requests.

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www.comcom.govt.nz

29 May 2020

Alec Findlater
General Manager, Regulatory and Commercial
Aurora Energy Limited

By email: alec.findlater@auroraenergy.nz

Dear Alec

Commerce Commission response: Aurora Energy Limited (Aurora) application for modifications and exemptions 30 April 2020

1. On 30 April 2020 you requested five modifications to, or exemptions from, the customised price-quality path (CPP) application requirements listed in clause 5.1.6(1) of the Electricity Distribution Services Input Methodologies Determination 2012[1] (IMs).

2. This letter advises you of our decision on each of these requests, including noting when our approval is subject to conditions and requirements that must be met by Aurora.

Summary of decisions

3. We approve the application of the following, as part of your CPP proposal in June 2020:

    3.1 modification of the cost allocation information (clause 5.4.9(4)(d)) to:

        3.1.1 recognise that Aurora will not be in a position to include audited information up to 31 March 2020 as part of its CPP proposal in June 2020; and

        3.1.2 allow Aurora to provide additional information to demonstrate the application of its new proposed cost allocation methodology and the changes to opex sharing arrangements during the CPP period,

        3.1.3 on the condition that Aurora provides the required cost allocation information for the 2020 disclosure year as soon as it is available, and no later than 1 September 2020 and confirms there have been no changes in the cost allocation methodology between 2019 and 2020;

[1] As consolidated 29 January 2020.

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Main office

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3.2 exemption from the requirement to provide information relating to other regulated income under clause 5.4.19(2) on the basis that it is not information that is required to determine the forecast regulatory tax allowance;

3.3 modification of clause 5.4.22(1) to allow Aurora to provide the opening unamortised balance of the initial differences in asset values at an aggregated level, rather than by asset category;

3.4 exemption from the requirement to provide information under clauses 5.4.23(1), (3) and (4) on the basis that this information is not required to inform the amortisation of revaluations calculations, which is its intended purpose; and

3.5 modification of clause 5.4.26(3) to allow Aurora to provide regulatory tax asset value information that includes use of diminishing value depreciation rates, rather than the specified 'weighted average remaining tax life of assets employed', where appropriate.

4. If Aurora relies on any of the modifications or exemptions approved in this letter, it must specify its reliance on that modification or exemption as part of its CPP application. The modifications and exemptions approved in this letter only apply to a CPP proposal submitted by Aurora in 2020.

5. The Commission has considered each of the modifications and exemptions proposed on its merits and in the context of your proposed 2020 CPP proposal. Nothing in this letter should be taken as an indication that a similar modification or exemption would be approved with respect to a different CPP proposal.

Modification to cost allocation information - clause 5.4.9(4)(d)

6. Clause 5.4.9(4)(d) requires that the cost allocation information in Schedule B of the IMs must be provided for the disclosure year prior to submitting a CPP proposal (which, based on a submission date on or around 12 June 2020, is the year ended 31 March 2020 for Aurora) if it has not already been disclosed in accordance with an Information Disclosure (ID) Determination at the time the CPP proposal is submitted.

7. Aurora notes that it will not be in a position to include audited information up to 31 March 2020 as part of its CPP proposal in June 2020. On this basis, Aurora requests a modification to clause 5.4.9(4)(d) so that it may disclose cost allocation information in Schedule B for the 2019 disclosure year (its most recently available audited full year data) on condition that it provides the corresponding 2020 disclosure year information as soon as it is available.

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8. Aurora requests a modification to clause 5.4.9(4)(d) to require that it provide some of the required cost allocation information in schedule B for all years of the 'next period'[2] (2021 – 2026 disclosure years). This is a higher threshold of required information under clause 5.4.9(4)(d)(ii), which requires the cost allocation information be provided for the next period "where a value in units in an allocator metric has been changed by at least 5% from the value used in the [disclosure year ended 31 March 2019]".[3] Aurora notes this additional information will help demonstrate the application of Aurora's new proposed cost allocation methodology and the changes to opex sharing arrangements during the CPP period.

9. We are satisfied that Aurora's requested modifications to clause 5.4.9(4)(d) will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

10. While we are comfortable granting the modification described at paragraph 8, we note that Aurora Energy could have provided this additional information at its own discretion without the modification.

11. Accordingly, the Commission approves the modification of clause 5.4.9(4)(d) by:

11.1 removing the following text:

(d) the information in Schedule B must be provided-

(i) for the **disclosure year** prior to submitting the **CPP proposal** if it has not been disclosed in accordance with an **ID determination**; and

(ii) for the **next period** where a value in units in an **allocator metric** has been changed by at least 5% from the value used in the **disclosure year** referred to in (i).

11.2 and replacing it with the following text:

(d) the information in Table 1 and Table 2 of Schedule B must be provided-

(i) for the **disclosure year** ended 31 March 2019 ~~prior to submitting the CPP proposal if it has not been disclosed in accordance with an ID determination~~; and

(ii) for the **next period** where a value in units in an **allocator metric** has been changed by at least 5% from the value used in the **disclosure year** referred to in (i).

(e) the information in Table 3, Table 4 and Table 5 of Schedule B must be provided-

(i) for the **disclosure year** ended 31 March 2019; and

(ii) for each **disclosure year** of the **next period**

[2] 'Next period' is defined in the IMs. In Aurora's case it is FY2021 – FY2026.
[3] The insertion of the disclosure year ended 31 March 2019 reflects Aurora's requested IM modification at paragraph 7. The IMs contemplate FY2020 in respect of Aurora's CPP proposal timing.

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(f) in support of Schedule B, the CPP Proposal must contain:

(i) confirmation that the allocation methodology used for the forecast **closing RAB value** and forecast **operating expenditure** for the **disclosure year** ended 31 March 2020 is the same as the allocation methodology used for the **closing RAB value** and **operating expenditure** for the **disclosure year** ended 31 March 2019; or

(ii) a description of any differences between the allocation methodology used for the forecast **closing RAB value** and forecast **operating expenditure** for the **disclosure year** ended 31 March 2020 and the allocation methodology used for the **closing RAB value** and **operating expenditure** for the **disclosure year** ended 31 March 2019;

11.3 on the condition that Aurora provides the information in Schedule B for the 2020 disclosure year as soon as it is available, and no later than 1 September 2020.

12. We understand from Aurora that it expects to achieve its normal end-August submission date for information disclosure requirements, which would include audited cost allocation information for FY2020.[4]

Exemption from providing regulatory tax allowance information - clause 5.4.19(2)

13. Regulatory tax allowance information is required to be included in a CPP proposal, including in relation to other regulated income (clause 5.4.19(2) refers).

14. Aurora requests an exemption from the requirement to provide information relating to other regulated income under clause 5.4.19(2).

15. As Aurora suggests, other regulated income is not a component of forecast regulatory taxable income (clause 5.3.13(3)) as it is not included in building blocks allowable revenue before tax (clause 5.3.2) for a CPP. We acknowledge that it is not required when determining the forecast regulatory tax allowance.

16. We are satisfied that the requested exemption to clause 5.4.19(2) will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

17. Accordingly, the Commission approves the exemption from the requirements in clause 5.4.19(2).

[4] Aurora notes that this expectation was subject to any unexpected Covid-19 issues/restrictions, such as a return to alert level 4 or similar, which it expects would compromise the timing of its ID information submission. Alec Findlater email to Karen Smith 5 May 2020.

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Modification to amortisation of initial differences in asset values information – clause 5.4.22(1)

18. Tax information is required to be included in a CPP proposal. Clause 5.4.22(1) requires the opening unamortised balance of the initial difference in asset values to be provide by asset category. Aurora submits that determining values by asset category would require an allocation of the aggregate opening balance each year, and suggests this requirement is costly, adds complexity and does not appear to add value to the Commission's analysis.

19. Aurora requests a modification to clause 5.4.22(1) to allow it to provide the opening unamortised balance of the initial differences in asset values at an aggregated level, rather than by asset category.

20. We are satisfied that the requested modification to clause 5.4.22(1) will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

21. Accordingly, the Commission approves the modification of clause 5.4.22(1) by:

    21.1 removing the following text:

    (1) opening unamortised balance of the initial differences in asset values by **asset category**

    21.2 and replacing it with the following text:

    (2) opening unamortised balance of the initial differences in asset values ~~by asset category~~

Exemption from providing amortisation of revaluations information – clause 5.4.23(1), (3) and (4)

22. Tax information is required to be included in a CPP proposal, including amortisation of revaluations information. Under clause 5.4.23 this includes:

    22.1 unamortised balance of revaluations to date (clause 5.4.23(1));

    22.2 adjusted depreciation (clause 5.4.23(2));

    22.3 average weighted remaining useful life of the assets used to determine the amortisation of revaluations (clause 5.4.23(3)); and

    22.4 particulars of how the average weighted remaining useful life was calculated (clause 5.4.23(4))

23. Aurora requests an exemption from the requirement to provide information under clauses 5.4.23(1), (3) and (4), noting that this information cannot be calculated in the context in which it is required.

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24. As noted by Aurora, the amortisation of revaluations is calculated as the difference between adjusted depreciation and tax depreciation, as per clause 5.3.18 of the IMs, and its calculation does not rely on the weighted average remaining life of assets.

25. We are satisfied that the requested exemption from clause 5.4.23(1), (3) and (4) will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

Modification to regulatory tax asset lives – clause 5.4.26(3)

26. Clause 5.4.26 requires regulatory tax asset value information is provided in a CPP proposal, including weighted average remaining tax life of assets employed (clause 5.4.26(3)).

27. Aurora notes that the tax depreciation methodology it uses for the purposes of deriving the tax components of the BBAR is the diminishing value method, in accordance with other IM rules and tax rules. Aurora requests a modification to provide information supporting the tax asset value to enable the specification of diminishing value rates, rather than useful lives, where appropriate.

28. We acknowledge that the diminishing value rate is required to calculate tax depreciation for tax asset roll-forward purposes.

29. We are satisfied that the requested modification from clause 5.4.26(3) will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

30. Accordingly, the Commission approves the modification of clause 5.4.22(1) by:

    30.1 removing the following text:

        (3) weighted average remaining tax life of assets employed

    30.2 and replacing it with the following text:

        (3) weighted average remaining tax life of assets employed <u>or weighted average diminishing value tax rate applied, as appropriate</u>

Yours sincerely

S.J. Begg

Sue Begg
Deputy Chair

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5 June 2020

Alec Findlater
General Manager, Regulatory and Commercial
Aurora Energy Limited

By email: alec.findlater@auroraenergy.nz

Dear Alec

Commerce Commission response: Aurora Energy application for modifications and exemptions 27 March 2020

1. On 27 March 2020 Aurora Energy Limited (Aurora) requested five modifications to, and exemptions from, the customised price-quality path (CPP) application requirements listed in clause 5.1.6(1) of the Electricity Distribution Services Input Methodologies Determination 2012[1] (IMs).

2. This letter advises you of our decision on each of Aurora's modification and exemption requests, including noting when our approval is subject to conditions and requirements that must be met by Aurora.

3. We acknowledge receipt of Aurora's letter dated 30 April 2020, seeking additional modifications and exemptions from the IMs, and will advise you of our decision on those requests in due course.

Summary of decisions

4. We approve Aurora electing to apply, as part of its CPP proposal in June 2020:

   4.1 modification to the use of the term 'current period' and 'assessment period' defined in clause 1.1.4, only where it applies to subpart 1, subpart 4 and subpart 5 (and the schedules to those subparts) of Part 5 of the IMs,

      4.1.1 on the condition that Aurora provides all financial information that would be required by the IMs had this modification not been applied (so for the disclosure year ending 31 March 2020) as soon as it is available, and no later than 1 September 2020; and

   4.2 exemption from clause 5.4.3, which requires a CPP proposal to explain why the proposal deserves to be prioritised for assessment before other CPP proposals.

[1] As consolidated 29 January 2020.

5. We consider Aurora's requested modification to clause 5.4.23(3) to be superseded by Aurora's later request for an exemption from clause 5.4.23, which requires amortisation of revaluations information to be provided [letter dated 30 April 2020 refers]. We are currently considering Aurora's requested exemption to clause 5.4.23 and will advise Aurora of our decision in due course.

6. In accordance with clause 5.1.6 of the IMs, we are not permitted to approve Aurora electing to apply, as part of its CPP proposal in June 2020:

   6.1 modification to clause 3.3.2 to permit Aurora to spread the impact of the opex incentive amount; and

   6.2 modification to clause 3.1.3 to permit Aurora to recover costs in disclosure year 2021 that are above the DPP allowance.

7. While we do not approve the requested modifications in paragraph 6, with the agreement of Aurora, we are permitted to vary IMs that would otherwise apply to our determination of Aurora's CPP.[2] Aurora may wish to request IM variations to give effect to the outcomes sought by the requested modifications in paragraph 6. This letter discusses relevant next steps, should Aurora wish to do so.

8. If Aurora relies on any of the modifications or exemptions approved in this letter, it must specify its reliance on that modification or exemption as part of its CPP application. The modifications and exemptions approved in this letter only apply to a CPP proposal submitted by Aurora in June 2020.

9. The Commission has considered each of the modifications and exemptions proposed by Aurora on its merits and in the context of Aurora's proposed 2020 CPP proposal. Nothing in this letter should be taken as an indication that a similar modification or exemption would be approved with respect to a different CPP proposal.

Modification to the definition of current period and assessment period - clause 1.1.4

10. Under clause 1.1.4 *current period* means the 5 disclosure years preceding the disclosure year in which the CPP application is submitted. This corresponds to the five years from 1 April 2015 to 31 March 2020 for the purposes of Aurora's CPP proposal.

11. Aurora seeks to modify clause 1.1.4, as it applies to Aurora's CPP proposal, to specify the disclosure years that will make up the current period – i.e. the five years from 1 April 2014 to 31 March 2019.

12. Aurora seeks this modification on the basis that it will have insufficient time to complete its financial information on an audited basis prior to the date it intends to submit the CPP proposal in June 2020. Aurora has submitted that it intends to provide FY2020 information a few months after it submits its CPP proposal.

[2] Section 53V(2)(c) of the Commerce Act 1986.

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13. Changing the definition of 'current period' to remove FY2020 information, as is sought by Aurora, also requires changes to the definition of 'assessment period' (clause 1.1.4) so that Aurora's proposal includes forecast FY2020 information alongside forecast FY2021 information. Without this change, the defined 'assessment period' would only require Aurora's CPP proposal to include forecast information for the disclosure period prior to the proposed CPP commencing on 1 April 2021 (ie, FY2021) as it assumes FY2020 is captured by the 'current period'. Inclusion of forecast FY2020 information closes the gap between the FY2015 TO FY2019 information (actuals) and the forecast FY2021.

14. We are satisfied that Aurora providing information for the period 1 April 2014 to 31 March 2019 in its CPP proposal and forecast information for the period 1 April 2019 to 31 March 2020 will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

15. Accordingly, the Commission approves the following modifications:

    15.1 modification of the term 'current period' as it appears in subpart 1, subpart 4, subpart 5 of Part 5 and the schedules to those subparts by replacing each occasion where 'current period' occurs in those subparts and schedules with the following text:

    > 5 disclosure years from 1 April 2014 to 31 March 2019

    15.2 modification of the term 'assessment period' as it appears in subpart 1, subpart 4, subpart 5 of Part 5 and the schedules to those subparts by replacing each occasion where 'assessment period' occurs in those subparts and schedules with the following text:

    > period between 31 March 2019 and the EDB's anticipated commencement date of the CPP

    15.3 on the condition that Aurora provides all financial information that would be required by the IMs had this modification not been applied (so for the disclosure year ending 31 March 2020) as soon as it is available, and no later than 1 September 2020.

Receiving Aurora's FY2020 information

16. We understand from correspondence with Aurora that we can expect to receive Aurora's information for the disclosure year ending 31 March 2020 by the end of August. Please get in touch as soon as you are made aware, if Aurora anticipates delays in providing this information beyond August 2020.

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Related modification request to cost allocation information – clause 5.4.9(4)(d)

17. We note that Aurora has requested, in its letter dated 30 April 2020, modification to cost allocation information [clause 5.4.9(4)(d)] that also arise from the status of its FY2020 information. We are considering this request and will advise you of our decision on this request in due course.

Exemption from requirement to explain priority - clause 5.4.3

18. Clause 5.4.3 requires a CPP proposal to explain why the proposal deserves to be prioritised for assessment before other CPP proposals, were the Commission to exercise its prioritisation powers under s 53Z of the Act.

19. Aurora requests an exemption from the requirement under clause 5.4.3 as it considers it unnecessary, suggesting there does not appear to be any prospect of the Commission needing to exercise its prioritisation powers under s 53Z of the Act.

20. We are satisfied that the requested exemption to clause 5.4.3 in this case will not detract, to an extent that is more than minor, from the Commission's evaluation or determination of the CPP proposal or the ability of interested persons to consider and provide their views on the CPP proposal.

21. Accordingly, the Commission approves the exemption from the requirements in clause 5.4.3.

Modification to amortisation of revaluations information – clause 5.4.23(3)

22. In its letter dated 27 March 2020, Aurora requested a modification to clause 5.4.23(3) to clarify how it derives the average weighted remaining useful life of the assets used to determine the amortisation of revaluations. We are not advising of our decision on this request because we consider it to be superseded by Aurora's letter dated 30 April 2020, which requests an exemption from the requirement to provide an unamortised revaluations balance and accompanying weighted average remaining life (clause 5.4.23).

23. We are considering Aurora's requested exemption to clause 5.4.23 and will advise Aurora of our decision in due course.

Spreading the opex incentive amount – clause 3.3.2

24. Clause 3.3.2 (subpart 3 of Part 3) details how opex incentive amounts are calculated under the incremental rolling incentive scheme (IRIS).

25. Aurora seeks to modify this clause to permit it to spread the impact of the opex IRIS incentive over two regulatory periods (ie, its proposed three year CPP and five year CPP).

26. As Aurora notes, under the current IMs the opex incentive is required to be recovered over the final two years of its proposed three year CPP. This generates

larger shifts in year-on-year price increases to consumers, compared to those that would arise if the opex incentive amount were spread over more years.

27. We do not approve the modification to clause 3.3.2 sought by Aurora on the basis that we are not permitted to do so under clause 5.1.6 of the IMs.

28. Nonetheless, we agree in principle with the price smoothing that Aurora is seeking to achieve and are open to considering Aurora's proposed change to clause 3.1.3 and/or other ways to give effect to the price 'smoothing' that Aurora is seeking. We are open to considering this as part of an IM variation which we discuss below.

Aurora may wish to request an IM variation to spread the opex incentive

29. While we cannot approve the requested modification to clause 3.1.3, we are permitted to vary IMs that would apply to our determination of Aurora's CPP with the agreement of Aurora.[3]

30. In conjunction with providing its CPP proposal, Aurora may wish to request, in writing, an IM variation to clause 3.1.3. To inform our consideration of such a request, we encourage Aurora to provide:

    30.1 an explanation of the IM variation and why it is sought (you may wish to draw on the material provided in Aurora's application seeking an IM modification); and

    30.2 information to show how the IM variation is expected to change the annual revenue profile (ie, the maximum allowable revenue) over the proposed three year and five year CPP compared to the revenue if the proposed IM variation were applied.

Urgent project allowance – clause 3.1.3

31. Clause 3.1.3(1) defines which costs are recoverable and includes urgent project allowances. Subclause 11 defines urgent project allowance.

32. Aurora notes it has incurred extensive unrecovered costs since late 2016 relating to its remedial investment programme, including incurring substantial IRIS penalties. Aurora expects to exceed the expenditure allowances under DPP3 until Aurora's CPP comes into effect and submits that the associated IRIS penalty is likely to result in a diminished incentive to invest in new assets. To mitigate this, Aurora seeks a modification to 3.1.3(11) to permit recovery of prudently incurred costs associated with its remediation *programme*, between the date of its CPP submission and the resulting CPP determination, and which exceed the DPP3 allowances. This departs from clause 3.1.3(11), which, among other things, defines urgent project allowance as costs that responded to an urgent *project*.

[3] Section 53V(2)(c) of the Commerce Act 1986.

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33. We do not approve the modification to clause 3.1.3(11) sought by Aurora on the basis that we are not permitted to do so under clause 5.1.6 of the IMs.

34. We note that Aurora's request for cost recovery is consistent with the Commission applying a 'clawback'. That is, allowing Aurora to recover, in the CPP period, a shortfall in its revenues that occurred under the prices previously charged by Aurora in DPP3 (s 52D(1)(b) of the Act refers).

Aurora may wish to request an IM variation to recover costs associated with its remediation programme

35. In conjunction with providing its CPP proposal, Aurora may wish to request the Commission apply a clawback to allow it to recover expenditure incurred by its remedial investment programme. We are open to considering this, including an IM variation proposed by Aurora that may help achieve this.

36. If Aurora seeks cost recovery of its remedial investment, we suggest Aurora provides information and explanation that links the expenditure it wishes to recover to a specific project or programme and the outcomes that are expected as a result of the expenditure.

Yours sincerely

Sue Begg
Deputy Chair

Appendix S. M&Es and Variations Relied Upon

S.1. IM Modifications and Exemptions

980. As required by IM clause 5.1.8(c), the M&Es we have elected to apply in our CPP Application are listed in Table 60, below.

Table 60: M&Es relied upon

Issue	IM clause	Modification or exemption
Definition of "current period"	1.1.4	A **modification** to the definition of "current period" to allow Aurora to disclose information for the five disclosure years from 1 April 2014 to 31 March 2019
Priority of proposals	5.4.3	An **exemption** from the requirement to provide prioritisation information.
Allocation information required in Schedule B	5.4.9(4)(d)	A **modification** to allow Aurora to include in the Schedule B tables: – the initial data for RY19 rather than RY20 – the provision of cost allocation information for all years of the next period
Regulatory tax allowance information	5.4.19(2)	An **exemption** from the requirement to provide information regarding other regulated income
Provision of initial differences information by asset category	5.4.22(1)	A **modification** to allow Aurora to provide the opening unamortised balance of the initial differences in asset values at an aggregated level
Amortisation of revaluations	5.4.23	An **exemption** from the requirement to provide an unamortised revaluations balance and accompanying weighted average remaining life
Regulatory tax asset lives	5.4.26	A **modification** to the information requirement to provide information supporting the tax asset value to enable the specification of diminishing value rates, rather than useful lives, where appropriate

S.2. IM Variations

982. As indicated in section 3.6, above, we have requested that certain IM variations are approved. While these are not yet approved, we have relied upon the proposed variations listed in Table 61, below.

Table 61: Requested IM variations relied upon

Issue	IM clause	Requested variation
Operating expenditure incentives	3.1.3	A variation to permit Aurora to spread the impact of the Opex IRIS incentive over two regulatory periods.
CPP opex forecast	5.3.5(1)	A variation to the cost allocation method used to determine the CPP Opex forecast to reflect Aurora's expected change to Opex sharing arrangements during the CPP period

Appendix T. Compliance Checklist (IM Part 5)

992. This compliance matrix provides a look-up reference for the information requirements relating to CPPs. The reference numbers are consistent with the clause numbers in Part 5 of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated at 29 January 2020).

Compliance Checklist (IM Part 5)

Index	IM clause	Description	Addressed by	Document reference	Section reference	Comments
1	**PART 5 INPUT METHODOLOGIES FOR CUSTOMISED PRICE-QUALITY PATHS**					
2	**SUBPART 1 Contents of a CPP application**					
3	5.1.1	Applying for a CPP				
4	5.1.1(1)	An EDB seeking a CPP in accordance with s 53Q of the Act must provide the Commission with a CPP application.	Application			
5	5.1.1(2)	CPP application means an application containing, in all material respects, the information specified in-				
6	5.1.1(2)(a)	this subpart; and	Application	Chapter 3		
7	5.1.1(2)(b)	Subpart 4.	Application	Chapter 4		
8	5.1.2	**Evidence of consumer consultation** For the purpose of clause 5.1.1(2)(a), in respect of consumer consultation, the specified information is-				Refer to Section 2.7 of the Consultation Report which sets out how Aurora fulfilled the regulatory requirements for
9	5.1.2(a)	a description as to how the requirements of clause 5.5.1 were met;	Consultation Report Application	Chapters 1 - 9 & Appendices A - I Chapter 3, Appendix C	Section 3.1	
10	5.1.2(b)	a list of respondents to the consultation required by that clause;	Consultation Report	Appendix B		
11	5.1.2(c)	a description of all issues raised by consumers in response to the CPP applicant's intended CPP proposal;	Consultation Report	Chapter 7 & Appendix E	Sections 7.2.1, E.3	
12	5.1.2(d)	a summary of the arguments raised in respect of each issue described in accordance with paragraph (c); and	Consultation Report	Chapter 7 & Appendix E	Section E.3	
13	5.1.2(e)	in respect of the issues described in accordance with paragraph (c), an explanation as to whether its CPP proposal accommodates the arguments referred to in (d); and	Consultation Report Application	Chapter 7 & Appendix E Appendix C	Section 7.2.2	
14	5.1.2(e)(i)	if so, how; and	Consultation Report Application	Chapter 7 & Appendix E Appendix C	Section 7.2.2	
15	5.1.2(e)(ii)	if not, why not.	Consultation Report Application	Chapter 7 & Appendix E Appendix C	Section 7.2.2	
16	5.1.3	**Verification-related material**				
17	5.1.3(1)	For the purpose of clause 5.1.1(2)(a), in respect of verification, the specified information is-				
18	5.1.3(1)(a)	a verification report;	IV Report			
19	5.1.3(1)(b)	any information relating to the CPP proposal, other than information required to be included in a CPP proposal by Subpart 4, provided to the verifier by or on behalf of the CPP applicant, pursuant to clauses 5.5.2(3)(a)-(c) and 5.5.2(3)(e); Examples: instructions as to how to interpret information provided to the verifier; details as to the source of the information;	IV Report Application	Appendix I Chapter 3, Appendix C	Sections 3.2, C.2.2	
20	5.1.3(1)(c)	any other information relied upon by the verifier relating to the CPP proposal pursuant to clause 5.5.2(3)(d); and	IV Report Application	Appendix I Chapter 3, Appendix C	Sections 3.2, C.2.2	
21	5.1.3(1)(d)	subject to subclause (2), a certificate signed by the verifier stating that the relevant parts of the CPP proposal were verified and verification report was prepared in accordance with Schedule G.	IV Report	Appendix H		
22	5.1.3(1)(2)	For the purpose of subclause (1)(d), the CPP applicant must ensure that the certificate described in subclause (1)(d) relates to verification of the relevant parts of the CPP proposal as submitted to the Commission.	Application	Chapter 3	Section 3.2	

23	5.1.4	**Audit and assurance reports**				
24	5.1.4(1)	For the purpose of clause 5.1.1(2)(a), in respect of audit or assurance, the specified information is a report written by an auditor and signed by that auditor (either in an individual's name or that of a firm) in respect of an audit or assurance engagement undertaken of the matters specified in clause 5.5.3, stating-	Application	Chapter 3, Appendix Q	Section 3.3	
25	5.1.4(1)(a)	the work done by the auditor;	Application	Chapter 3, Appendix Q	Section 3.3	
26	5.1.4(1)(b)	the scope and limitations of the audit or assurance engagement;	Application	Chapter 3, Appendix Q	Section 3.3	
27	5.1.4(1)(c)	the existence of any relationships (other than that of auditor) which the auditor has with, or any interests which the auditor has in, the CPP applicant or any of its subsidiaries;	Application	Chapter 3, Appendix Q	Section 3.3	
28	5.1.4(1)(d)	whether the auditor obtained all information and explanations that he or she required to undertake the audit or assurance engagement, and, if not-	Application	Chapter 3, Appendix Q	Section 3.3	
29	5.1.4(1)(d)(i)	details of the information and explanations not obtained; and	Application	Chapter 3, Appendix Q	Section 3.3	Not applicable - the Auditor's report (set out at Appendix Q of the Application) notes that the Auditor obtained all information and
30	5.1.4(1)(d)(ii)	any reasons provided by the CPP applicant for its or their non-provision;	Application	Chapter 3, Appendix Q	Section 3.3	Not applicable - the Auditor's report (set out at Appendix Q of the Application) notes that the Auditor obtained all information and
31	5.1.4(1)(e)	the auditor's opinion of the matters in respect of which the audit or assurance engagement was undertaken.	Application	Chapter 3, Appendix Q	Section 3.3	
32	5.1.4(2)	A report in respect of an audit or assurance engagement undertaken other than expressly to meet the requirements of clause 5.5.3 may be considered to comply with subclause (1) to the extent that the report in respect of that other audit or assurance engagement fully or partially meets the requirements of clause 5.5.3.	N / A			Not applicable - the Auditor's report has been written to meet the requirement of clause 5.5.3 only.
33	5.1.4(3)	The CPP applicant must ensure that reports required by this clause relate to the CPP proposal as submitted to the Commission.	Application	Chapter 3, Appendix Q	Section 3.3	
34	5.1.4(4)	For the avoidance of doubt, the reports required by this clause need not be-				
35	5.1.4(4)(a)	prepared in advance of the verifier undertaking verification of the CPP proposal; nor				
36	5.1.4(4)(b)	provided to the verifier.				
37	5.1.4(5)	If, notwithstanding subclause (4), a report prepared in accordance with this clause is provided to the verifier, subclause (3) continues to apply.				
38	5.1.5	**Certification**				
39	5.1.5(1)	For the purpose of clause 5.1.1(2)(a), in respect of certification, the specified information is the certificates recording the certifications specified in clause 5.5.4.	Application	Chapter 3, Appendix A	Section 3.4	
40	5.1.5(2)	For the avoidance of doubt, one physical document may contain more than one of the certifications specified in clause 5.5.4.				
41	5.1.6	**Modification or exemption of CPP application requirements**	Application	Chapter 3, Appendices R and S	Section 3.5	Refer to Aurora's applications for modifications and exemptions dated 27 March 2020 and 30 April 2020. Copies of the Commission's approval of these requests are set out at Appendix R.
42	5.1.6(1)	The Commission may approve a modification to, or exemption from, any requirement set out in—	N / A			
43	5.1.6(1)(a)	this subpart;	N / A			
44	5.1.6(1)(b)	Subpart 4;	N / A			
45	5.1.6(1)(c)	Subpart 5; or	N / A			
46	5.1.6(1)(d)	schedules relating to subparts identified in paragraphs (a) to (c) above.	N / A			
47	5.1.6(2)	A modification or exemption may be approved where, in the Commission's opinion, the modification or exemption will not detract, to an extent that is more than minor, from—	N / A			
48	5.1.6(2)(a)	the Commission's evaluation of the CPP proposal;	N / A			
49	5.1.6(2)(b)	the Commission's determination of a CPP; and	N / A			
50	5.1.6(2)(c)	the ability of interested persons to consider and provide their views on the CPP proposal.	N / A			

51	5.1.6(3)	When considering whether a modification or exemption is likely to detract, to an extent that is more than minor, from the processes listed in subclauses (2)(a)-(c), the Commission may have regard to the size of the supplier's business.	N / A			
52	5.1.6(4)	A modification or exemption will only apply for the purposes of assessing compliance of a CPP application under s 53S(1) of the Act—	N / A			
53	5.1.6(4)(a)	if the Commission has previously approved a request by a CPP applicant for the modification or exemption in accordance with clause 5.1.7;	N / A			
54	5.1.6(4)(b)	in respect of the CPP applicant and the CPP application identified in the Commission's approval; and	N / A			
55	5.1.6(4)(c)	if the CPP applicant elects to apply the modification or exemption by:	N / A			
56	5.1.6(4)(c)(i)	meeting all conditions and requirements specified in the approval that relates to the modification or exemption; and	N / A			
57	5.1.6(4)(c)(ii)	providing the relevant information specified in clause 5.1.8 as part of its CPP application.	N / A			
58	5.1.7	**Process for obtaining a modification or exemption**	N / A			
59	5.1.7(1)	At any time prior to providing the Commission with a CPP application, a CPP applicant may request modifications or exemptions to the requirements listed in clause 5.1.6(1) as alternatives to those requirements.	Application	Chapter 3, Appendices R and S	Section 3.5	Refer to Aurora's applications for modifications and exemptions dated 27 March 2020 and 30 April 2020. Copies of the Commission's approval of
60	5.1.7(2)	A request by a CPP applicant must—	Application	Chapter 3, Appendices R and S	Section 3.5	
61	5.1.7(2)(a)	be in writing;	Application	Chapter 3, Appendices R and S	Section 3.5	
62	5.1.7(2)(b)	include the following information:	Application	Chapter 3, Appendices R and S	Section 3.5	
63	5.1.7(2)(b)(i)	the CPP applicant's name and contact details;	Application	Chapter 3, Appendices R and S	Section 3.5	
64	5.1.7(2)(b)(ii)	a brief description of the key features of its intended CPP proposal;	Application	Chapter 3, Appendices R and S	Section 3.5	
65	5.1.7(2)(b)(iii)	the date that the CPP applicant intends to submit the CPP application for which a modification or exemption is sought;	Application	Chapter 3, Appendices R and S	Section 3.5	
66	5.1.7(2)(b)(iv)	a list of the specific modifications or exemptions sought;	Application	Chapter 3, Appendices R and S	Section 3.5	
67	5.1.7(2)(b)(v)	an explanation of why the CPP applicant considers the requirements in clause 5.1.6(2) are met;	Application	Chapter 3, Appendices R and S	Section 3.5	
68	5.1.7(2)(b)(vi)	evidence in support of the explanation provided under subparagraph (v); and	Application	Chapter 3, Appendices R and S	Section 3.5	
69	5.1.7(2)(b)(vii)	identification of any information that is commercially sensitive.	Application	Chapter 3, Appendices R and S	Section 3.5	
70	5.1.7(3)	Subparagraph (2)(b)(vi) may be satisfied by submitting a certificate, signed by a senior manager of the CPP applicant, setting out the factual basis on which he or she believes the requirements in subclause 5.1.6(2) are met.	Application	Chapter 3, Appendices R and S	Section 3.5	
71	5.1.7(4)	In considering whether to approve a request for modification or exemptions, the Commission may seek, and have regard to—	N / A			
72	5.1.7(4)(a)	views of interested persons within any time frames and processes set by the Commission; and	N / A			
73	5.1.7(4)(b)	views of any person the Commission considers has expertise on a relevant matter.	N / A			
74	5.1.7(5)	As soon as reasonably practicable after receipt of a request for modifications or exemptions the Commission will, by notice in writing, advise the CPP applicant as to whether:	Application	Appendix R		Approved modifications and exemptions are set out in Appendix R.
75	5.1.7(5)(a)	any of the modifications or exemptions are approved; and	Application	Appendix R		
76	5.1.7(5)(b)	the approval of any modification or exemption is subject to conditions or requirements that must be met by the CPP applicant.	Application	Appendix R		
77	5.1.8	**Information on modification or exemption of information requirements**				
78		Where a CPP applicant elects to apply a modification or exemption approved by the Commission in accordance with clause 5.1.7, it must include as part of its CPP application—	Application	Chapter 3, Appendix S	Section 3.5	
79	5.1.8(a)	a copy of the Commission's approval;	Application	Appendix R		

80	5.1.8(b)	a list of the approved modifications or exemptions which the CPP applicant has elected to apply in its CPP application;	Application	Chapter 3, Appendix S	Section 3.5	
81	5.1.8(c)	evidence that any conditions or requirements of the approval have been met; and	Application	Chapter 3, Appendix S	Section 3.5	
82	5.1.8(d)	an indication, at the relevant locations within the document or documents comprising the CPP application, as to where the modifications or exemptions have been applied.	Application Financial/Model report	Chapter 3, Appendix S Chapter 2.1	Section 3.5 Table 2.1	
83	**SUBPART 2 Commission assessment of a customised price-quality path proposal**					
84	5.2.1	**Evaluation criteria**	N / A			
85		The Commission will use the following evaluation criteria to assess each CPP proposal:	N / A			
86	5.2.1(a)	whether the CPP proposal is consistent with the input methodologies specified in Part 5;	N / A			
87	5.2.1(b)	the extent to which a CPP in accordance with the CPP proposal would promote the purpose of Part 4 of the Act;	N / A			
88	5.2.1(c)	whether data, analysis, and assumptions underpinning the CPP proposal are fit for the purpose of the Commission determining a CPP under s 53V, including consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement;	N / A			
89	5.2.1(d)	whether proposed capital expenditure and operating expenditure meet the expenditure objective;	N / A			
90	5.2.1(e)	the extent to which any proposed quality standard variation provided in a CPP proposal better reflects the realistically achievable performance of the EDB over the CPP regulatory period, taking into account either or both-	N / A			
91	5.2.1(e)(i)	statistical analysis of past SAIDI and SAIFI performance; and	N / A			
92	5.2.1(e)(ii)	the level of investment provided for in proposed maximum allowable revenue before tax,	N / A			
93		as the case may be; and	N / A			
94	5.2.1(e)(f)	the extent to which-	N / A			
95	5.2.1(e)(f)(i)	the CPP applicant has consulted with consumers on its CPP proposal; and	N / A			
96	5.2.1(e)(f)(ii)	the CPP proposal is supported by consumers, where relevant.	N / A			
97	**SUBPART 3 Commission assessment of a customised price-quality path proposal**					
98	**SECTION 1 Determination of annual allowable revenues**					
99	5.3.1	**Annual allowable revenues**	Financial/Model report	Chapters 4, 5		
100		Amounts for-				
101	5.3.1(a)	building blocks allowable revenue before tax for the next period;	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$H$15:$N$15		
102	5.3.1(b)	building blocks allowable revenue after tax for the next period;	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$H$17:$N$17		
103	5.3.1(c)	maximum allowable revenue before tax for the CPP regulatory period; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$J$19:$N$19		
104	5.3.1(d)	maximum allowable revenue after tax for the CPP regulatory period,	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$J$21:$N$21		
105		will be determined.				
106	5.3.2	**Building blocks allowable revenue before tax**	Financial/Model report	Chapter 5		
107	5.3.2(1)	'Building blocks allowable revenue before tax' for each disclosure year of the next period is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]BBARx'!$H$37:$N$37		In addition, refer to Section 5.1 of Chapter 5 in the Financial/Model Report
108		(regulatory investment value × cost of capital + total value of commissioned assets × (TF_{VCA} - 1) + term credit spread differential allowance × TF - total revaluation) ÷ (TF_{rev} - corporate tax rate × TF)				
109		+ (total depreciation × (1 – corporate tax rate × TF)				

110		+ forecast operating expenditure × TF × (1 – corporate tax rate)				
111		+ (closing deferred tax – opening deferred tax) × (TF – 1)				
112		+ (permanent differences + regulatory tax adjustments - utilised tax losses) × corporate tax rate × TF) ÷ (TF_{rev} - corporate tax rate × TF).				
113	5.3.2(2)	'Regulatory investment value' means the amount obtained in accordance with the formula-	Financial/Model report	Chapter 5	Section 5.2	
114		total opening RAB value + opening deferred tax.	Financial/Model report	Chapter 5	Section 5.2	
115	5.3.2(3)	For the purpose of subclause (1) 'total value of commissioned assets' means, in relation to a disclosure year, the sum of closing RAB values for all commissioned assets calculated in accordance with clause 5.3.6(3)(b).	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$17:$N$17		The value of commissioned assets throughout the model is the sum of closing RAB values in the year that they are acquired (noting that revaluations and depreciation are only applied to opening RAB values and a commissioned asset does not have an opening RAB value in the year it is commissioned). In addition, refer to Section 7.3 in
116	5.3.2(4)	For the purpose of subclause (1) –	Financial/Model report	Chapter 9	Section 9.1	
117	5.3.2(4)(a)	'TF' is determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$14:$S$14		
118		(1 + cost of capital)182/365;				
119	5.3.2(4)(b)	'TFrev' is determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$15:$S$15		
120		(1 + cost of capital)148/365;				
121	5.3.2(4)(c)	'TFVCA' is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$33:$N$33		
122		PVVCA × (1 + cost of capital) ÷ total value of commissioned assets; and				
123	5.3.2(4)(d)	'PVVCA' means the sum of the present value of closing RAB values for commissioned assets calculated in accordance with clause 5.3.6(3)(b), where each present value is determined by discounting each closing RAB value by the cost of capital from the relevant commissioning date to the commencement of the relevant disclosure year.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$17:$S$17		
124	5.3.2(5)	For the purpose of this clause, 'cost of capital' has the meaning specified in clause 5.3.22.	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$15:$N$15		In addition, refer to Section 5.3 of Chapter 5 in the Financial/Model Report
125	5.3.2(6)	'Forecast operating expenditure' means, in relation to a CPP proposal -	Financial/Model report	Chapter 6		
126	5.3.2(6)(a)	that has not been assessed by the Commission, the amount of operating expenditure for the relevant disclosure year included by the CPP applicant in its opex forecast; or	Financial/Model report	Chapter 6		
127	5.3.2(6)(b)	undergoing assessment by the Commission, the amount of operating expenditure determined for the relevant disclosure year by the Commission after assessment of the amount in paragraph (a) against the expenditure objective.	Financial/Model report	Chapter 6		Forecast operating expenditure reflects our operating expenditure forecast for the forecast period in accordance with clause 5.3.2(6)(a) of the IMs. This has not yet been assessed by the Commission against the expenditure
128	5.3.2(7)	For the purpose of this clause, all values and amounts are expressed in nominal terms unless otherwise specified.	Financial Model	Included within '[1. CPP Financial Model vProposal.xlsm]'		
129	5.3.3	**Building blocks allowable revenue after tax**	Financial/Model report	Chapter 5	Section 5.1	
130	5.3.3(1)	'Building blocks allowable revenue after tax' is building blocks allowable revenue before tax less forecast regulatory tax allowance.	Financial Model	[1. CPP Financial Model vProposal.xlsm]BBARx'!$H$43:$N$43		
131	5.3.3(2)	For the purpose of this clause, all values and amounts are expressed in nominal terms.	Financial Model	Included within '[1. CPP Financial Model vProposal.xlsm]'		

132	5.3.4	**Price path**	Financial/Model report	Chapter 4		
133	5.3.4(1)	The present value of the series of values of maximum allowable revenue after tax must equal the present value of the series of building blocks allowable revenue after tax, adjusted for the present value of any claw-back for the CPP regulatory period, where present values are determined in accordance with subclause (3).	Financial Model	0		In addition, refer to Section 4.1 of Chapter 4 in the Financial/Model Report
134	5.3.4(2)	In subclause (1)-				
135	5.3.4(2)(a)	the reference to claw-back is a reference to claw-back, determined by the Commission pursuant to s 53V(2)(b), in the case of a CPP determination made-	Financial Model	0		The model can accommodate a claw-back input into the MAR calculations but no claw-back is forecast
136	5.3.4(2)(a)(i)	after deferral of the relevant CPP proposal in accordance with s 53Z(2) of the Act;				
137	5.3.4(2)(a)(ii)	in response to a CPP proposal made in accordance with provisions in a DPP determination relating to the submission of CPP proposals in response to a catastrophic event; or				
138	5.3.4(2)(a)(iii)	as a result of a reconsideration of the price-quality path in accordance with clause 5.6.7(1) and an amendment made to the price-quality path after reconsideration under clause 5.6.8(1); and				
139	5.3.4(2)(b)	each reference to a series of values is a reference to the value determined in respect of each disclosure year of the CPP regulatory period.				
140	5.3.4(3)	For the purpose of subclause (1), the present value of each series must be determined using the cost of capital as specified in clause 5.3.22.	Financial Model	[1. CPP Financial Model vProposal.xlsm]MARx '!$J$45:$N$45, [1. CPP Financial Model vProposal.xlsm]MARx '!$J$50:$N$50		
141	5.3.4(4)	For the avoidance of doubt, where claw-back is determined where-				
142	5.3.4(4)(a)	subclause (2)(a)(i) applies, it will only be determined in respect of the period between the date when the CPP would have taken effect had deferral not occurred and the date the CPP determination will come into effect; and				
143	5.3.4(4)(b)	subclause (2)(a)(ii) applies, it will only be determined in respect of the period between the date of the catastrophic event and the date the CPP determination will come into effect.				
144	5.3.4(5)	For the purpose of this subpart, the 'maximum allowable revenue before tax' for the first disclosure year of the CPP regulatory period is the amount of maximum allowable revenue before tax in the first disclosure year of the CPP regulatory period required for subclause (1) to be satisfied.	Financial Model	88,012,508		
145	5.3.4(6)	For the purpose of this subpart, the 'maximum allowable revenue before tax' for each disclosure year of the CPP regulatory period except the first must equal-	Financial Model	[1. CPP Financial Model vProposal.xlsm]MARx '!$J$20:$N$20		
146		$MAR_{y-1} \times (1 + \Delta CPI) \times (1 - X)$,				
147		where-				
148		MAR_{y-1} is the maximum allowable revenue before tax in the preceding disclosure year;				
149		ΔCPI is the CPP inflation rate; and				
150		X is any X factor applying to the EDB.				
151	5.3.4(7)	'Maximum allowable revenue after tax' is maximum allowable revenue before tax less forecast regulatory tax allowance.	Financial Model	[1. CPP Financial Model vProposal.xlsm]MARx '!$J$26:$N$26		In addition, refer to Section 4.1 of Chapter 4 in the Financial/Model Report
152	5.3.4(8)	For the purpose of subclause (7), 'forecast regulatory tax allowance' means-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$17:$N$17		
153	5.3.4(8)(a)	where opening tax losses are nil in every disclosure year of the next period, forecast regulatory tax allowance; and				

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154	5.3.4(8)(b)	in all other cases, the amount calculated in accordance with clause 5.3.13 with the modification that the reference in clause 5.3.13(4) to 'building blocks allowable revenue before tax' is substituted with 'maximum allowable revenue before tax'.				
155	5.3.4(9)	'CPP Inflation rate' means the amount determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$J$17:$N$17		In addition, refer to Section 4.3.1 of Chapter 4 in the Financial/Model Report
156		$[(CPI_1 + CPI_2 + CPI_3 + CPI_4) \div (CPI_1^{-4} + CPI_2^{-4} + CPI_3^{-4} + CPI_4^{-4})] -1$,				
157		where-				
158		CPI_n means forecast CPI for the nth quarter of the disclosure year in question; and				
159		CPI_n^{-4} means forecast CPI for the equivalent quarter in the preceding disclosure year.				
160	**SECTION 2 Cost allocation and asset valuation**		**N / A**	**N / A**	**N / A**	
161	5.3.5	**Allocating forecast values of operating costs not directly attributable**	Financial/Model report	Chapter 6	Section 6.1	
162	5.3.5(1)	Operating costs forecast in each disclosure year of the next period must, in the case of an operating cost for which disclosure pursuant to an ID determination has-	Financial/Model report	Chapter 6	Section 6.1	
163	5.3.5(1)(a)	been made for the last disclosure year of the current period, be consistent with the operating costs allocated to electricity distribution services in that disclosure; and	Financial/Model report	Chapter 6	Section 6.1	As explained in Section 6.1 of the Information Report, we have sought a variation to this IM requirement for the purpose of this CPP application.
164	5.3.5(1)(b)	not been so made, be consistent with an allocation of operating costs to electricity distribution services carried out in respect of the most recent disclosure made for the current period in accordance with clause 2.1.1.	Financial/Model report	Chapter 6	Section 6.1	As explained in Section 6.1 of the Information Report, we have sought a variation to this IM requirement for the purpose of this CPP application.
165	5.3.5(2)	Where a sale of the assets used to supply electricity distribution services and either or both-	Financial/Model report	Chapter 7	Section 7.2.1	Not applicable - there are no forecast asset sales that meet the defintion of
166	5.3.5(2)(a)	an other regulated service; and	N / A			
167	5.3.5(2)(b)	an unregulated service,	N / A			
168		is	N / A			
169	5.3.5(2)(c)	completed between the start of the assessment period and the time the CPP application is made; or	N / A			
170	5.3.5(2)(d)	highly probable,	N / A			
171		operating costs attributable to electricity distribution services, in respect of each operating cost not directly attributable affected by the sale, is determined as the value allocated to electricity distribution services as a result of applying clause 2.1.1 in respect of the last disclosure year of the assessment period.	N / A			
172	5.3.6	**RAB roll forward**	Financial/Model report	Chapter 7	Section 7.2	
173	5.3.6(1)	The opening RAB value of an asset in relation to-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx'!$H$13:$N$13		
174	5.3.6(1)(a)	the disclosure year 2010, is the initial RAB value; and				
175	5.3.6(1)(b)	a disclosure year thereafter, is, where the disclosure year-				
176	5.3.6(1)(b)(i)	follows a disclosure year in respect of which disclosure pursuant to an ID determination relating to that asset has been made, that asset's disclosed closing RAB value;				
177	5.3.6(1)(b)(ii)	is the first disclosure year of the next period for which disclosure pursuant to an ID determination relating to that asset for the preceding disclosure year has not been made, determined in accordance with subclause (2); or				
178	5.3.6(1)(b)(iii)	is any other disclosure year, the closing RAB value for the preceding disclosure year.				
179	5.3.6(2)	For the purpose of subclause (1)(b)(ii), the opening RAB value of an asset to which this subclause applies is determined as the value allocated to electricity distribution services as a result of applying clause 2.1.1 to its unallocated closing RAB value for the preceding disclosure year.	Financial/Model report	Chapter 7	Section 7.2.1	Not applicable - there are no shared asset acquistions during the forecast period
180	5.3.6(3)	Closing RAB value means, subject to subclause (4), for an asset-	Financial/Model report	Chapter 7	Section 7.1	
181	5.3.6(3)(a)	with an opening RAB value, the value determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx'!$H$18:$N$18		

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182		opening RAB value - depreciation + revaluation;				
183	5.3.6(3)(b)	having or forecast to have a commissioning date in that disclosure year, where the asset-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$17:$N$17		
184	5.3.6(3)(b)(i)	has been commissioned by the date the CPP application is made, its value of commissioned asset; or				
185	5.3.6(3)(b)(ii)	has not been commissioned by the date the CPP application is made, its forecast value of commissioned asset,				
186		but only to the extent that the value would be included in the closing RAB value consistent with application of clause 2.1.1; or				
187	5.3.6(3)(c)	that is or is forecast to be a disposed asset, nil.	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$15:$N$15		
188	5.3.6(4)	For the purpose of subclause (3), where a sale of the assets used to supply electricity distribution services and either or both-	Financial/Model report	Chapter 7	Section 7.2.1	Not applicable - there are no forecast asset sales that meet the defintion of 5.3.6(4)
189	5.3.6(4)(a)	an other regulated service; and	N / A			
190	5.3.6(4)(b)	an unregulated service,	N / A			
191		is	N / A			
192	5.3.6(4)(c)	completed between the start of the assessment period and the time the CPP application is made; or	N / A			
193	5.3.6(4)(d)	highly probable,	N / A			
194		closing RAB value in respect of each asset not directly attributable affected by the sale is determined as the value allocated to electricity distribution services as a result of applying clause 2.1.1 in respect of its unallocated closing RAB value of the last disclosure year of the assessment period.	N / A			
195	5.3.6(5)	The unallocated opening RAB value of any asset in relation to-	Financial/Model report	Chapter 7	Section 7.1	Aurora only has a very small amount of shared assets. For most assets, the asset-level RAB roll-forward in the model reflects both the 'allocated' and 'unallocated' RAB. For the shared assets, the model includes a RAB roll-forward of the allocated value, and a roll-forward of the amount not allocated to electricity distribution. At an aggregate level, RAB is calculated by summing all asset-level RAB roll-forwards excluding that for shared assets not allocated to electricity distribution, and unallocated RAB is calculated as RAB plus the roll-forward
196	5.3.6(5)(a)	the disclosure year 2010, is the unallocated initial RAB value;				
197	5.3.6(5)(b)	a disclosure year thereafter, is, where the disclosure year-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'!$L$60:$S$60		
198	5.3.6(5)(b)(i)	follows a disclosure year in respect of which disclosure pursuant to an ID determination relating to that asset has been made, that asset's disclosed unallocated closing RAB value; and	Financial Model	447122975.1		
199	5.3.6(5)(b)(ii)	is any other disclosure year, its unallocated closing RAB value in the preceding disclosure year.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'!$N$60:$S$60		
200	5.3.6(6)	Unallocated closing RAB value means, in relation to-				Refer to the comment above in relation to clause 5.3.6(5).
201	5.3.6(6)(a)	an asset that is or is forecast to be a disposed asset, nil;	Financial/Model report	Chapter 7	Section 7.6	
202	5.3.6(6)(b)	any other asset with an unallocated opening RAB value, the value determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'!$L$65:$S$65		
203		unallocated opening RAB value - unallocated depreciation + unallocated revaluation; and				

204	5.3.6(6)(c)	any other asset-				
205	5.3.6(6)(c)(i)	that has a commissioning date between the commencement of the disclosure year in which the CPP application is made and the application's submission, its value of commissioned asset; or				
206	5.3.6(6)(c)(ii)	forecast to have a commissioning date thereafter, its forecast value of commissioned asset.				
207	5.3.6(7)	The total opening RAB value in relation to-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$13:$N$13		
208	5.3.6(7)(a)	the disclosure year 2010, is the sum of all initial RAB values; and				
209	5.3.6(7)(b)	any disclosure year thereafter, is the total closing RAB value in the preceding disclosure year.				
210	5.3.6(8)	For the purpose of subclause (7), 'total closing RAB value' means, in relation to a disclosure year, the sum of closing RAB values for all assets.	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$18:$N$18		
211	5.3.7	**Depreciation**	Financial/Model report	Chapter 7	Section 7.4	
212	5.3.7(1)	Total depreciation means the sum of depreciation calculated for existing CPP assets under subclause (2)(a) and for additional CPP assets under subclause (2)(b).	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$52:$N$52		
213	5.3.7(2)	For the purpose of subclause (1)-				
214	5.3.7(2)(a)	‘depreciation’, in the case of existing CPP assets with an opening RAB value, is determined, subject to subclause (3) and clauses 5.3.6 and 5.3.8, in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$52:$N$52		The average remaining asset life has been calculated for each disclosure year. This is then applied to the total opening RAB value to calculate total
215		[1 ÷ remaining asset life for existing CPP assets] × opening RAB value.				
216	5.3.7(2)(b)	‘depreciation’, in the case of additional CPP assets with an opening RAB value, is determined, subject to subclause (3) and clauses 5.3.6 and 5.3.8, in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$52:$N$52		The average remaining asset life has been calculated for each disclosure year. This is then applied to the total opening RAB value to calculate total
217		[1 ÷ remaining asset life for additional assets] × opening RAB value for additional CPP assets.				
218	5.3.7(3)	For the purposes of subclauses (1) and (2)-	Financial/Model report	Chapter 7	Section 7.4	
219	5.3.7(3)(a)	depreciation is nil in the case of-	Financial/Model report	Chapter 7	Section 7.4	No depreciation on land, easements or spares are calculated in the financial
220	5.3.7(3)(a)(i)	land; and	Financial/Model report	Chapter 7	Section 7.4	
221	5.3.7(3)(a)(ii)	an easement other than a fixed life easement; and	Financial/Model report	Chapter 7	Section 7.4	
222	5.3.7(3)(a)(iii)	network spare in respect of the period before which depreciation for the network spare in question commences under GAAP; and	Financial/Model report	Chapter 7	Section 7.4	
223	5.3.7(3)(b)	in all other cases, where the asset's physical asset life at the end of the disclosure year is nil-				
224	5.3.7(3)(b)(i)	unallocated depreciation is the asset's unallocated opening RAB value; and	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'! $M$204:$S$210		
225	5.3.7(3)(b)(ii)	depreciation is the asset's opening RAB value.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'! $M$204:$S$210		
226	5.3.7(4)	For the purpose of subclause (2)-				
227	5.3.7(4)(a)	‘remaining asset life for existing CPP assets’ means, for each asset, the value determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'! $H$161:$S$161		
228		opening RAB value ÷ depreciation for the last year of the current period,				
229		less the number of disclosure years from the last year of the current period to the disclosure year in question; and				
230	5.3.7(4)(b)	‘remaining asset life for additional assets’ means the asset life for CPP commissioned assets for an asset category less the number of disclosure years from the disclosure year in which the additional assets are forecast to be commissioned.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'! $M$850:$S$850		

231	5.3.8	**Depreciation - alternative depreciation method**	Financial/Model report	Chapter 7	Section 7.4	Alternative depreciation not applied
232	5.3.8(1)	Depreciation and, subject to clause 5.3.9, unallocated depreciation may be determined in respect of a CPP regulatory period using an alternative depreciation method, provided the Commission is satisfied that the result of applying the alternative depreciation method would better promote the purpose of Part 4 than the result of applying the standard depreciation method.	N / A			
233	5.3.8(2)	For the avoidance of doubt, subclause (1) does not apply to the determination of depreciation or unallocated depreciation in the assessment period.	N / A			
234	5.3.9	**Unallocated depreciation constraint**	Financial/Model report	Chapter 7	Section 7.4	
235		For the purposes of clauses 5.3.7 and 5.3.8, the sum of unallocated depreciation of an asset calculated over its asset life may not exceed the sum of-	Financial/Model report	Chapter 7	Section 7.4	
236	5.3.9(a)	all unallocated revaluations applying to that asset in all disclosure years; and	Financial/Model report	Chapter 7	Section 7.4	
237	5.3.9(b)	in the case of an asset-	Financial/Model report	Chapter 7	Section 7.4	
238	5.3.9(b)(i)	in the initial RAB, its unallocated initial RAB value; and	Financial/Model report	Chapter 7	Section 7.4	
239	5.3.9(b)(ii)	not in the initial RAB, its value of commissioned asset or forecast value of commissioned asset, as the case may be.	Financial/Model report	Chapter 7	Section 7.4	
240	5.3.10	**Revaluation**	Financial/Model report	Chapter 7	Section 7.5	
241	5.3.10(1)	Unallocated revaluation, subject to subclause (3), is determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RAB'!$L$62:$S$62		For the purposes of the financial model, unallocated revaluation is calculated as the sum of allocated revaluation and revaluation on assets that are not
242		unallocated opening RAB value × revaluation rate.				
243	5.3.10(2)	Revaluation, subject to subclause (3), is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx'!$H$46:$N$46		
244		opening RAB value × revaluation rate.				
245	5.3.10(3)	For the purposes of subclauses (1) and (2), where-	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx'!$H$42:$N$43		
246	5.3.10(3)(a)	the asset's physical asset life at the end of the disclosure year is nil; or				
247	5.3.10(3)(b)	the asset is a-				
248	5.3.10(3)(b)(i)	disposed asset; or				
249	5.3.10(3)(b)(ii)	lost asset,				
250		unallocated revaluation and revaluation are nil.				
251	5.3.10(4)	Revaluation rate means, in respect of a disclosure year, the amount determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$71:$N$71		
252		(CPI4 ÷ CPI4-4) -1,				
253		where-				
254		CPI4 means forecast CPI for CPP revaluation for the quarter that coincides with the end of the disclosure year; and				
255		CPI4-4 means forecast CPI for CPP revaluation for the quarter that coincides with the end of the preceding disclosure year.				
256	5.3.10(5)	Forecast CPI for CPP revaluation means, for the purpose of subclause (4), when calculating the revaluation rate-				
257	5.3.10(5)(a)	in the CPP regulatory period and up to the end of the DPP regulatory period, as for forecast CPI for DPP revaluation in accordance with clause 4.2.3(4)(a); and	Financial Model	[CPI-model-EDB-DPP3-final-determination-27-November-2019.xlsx]Output'!$H$8:$N$8		
258	5.3.10(5)(b)	for each later quarter for which a forecast of the change in headline CPI has been included in the Monetary Policy Statement last issued by the Reserve Bank of New Zealand prior to the date for which the vanilla WACC applicable to the relevant DPP regulatory period was determined, the CPI last applying under paragraph (a) extended by the forecast change; and	Financial Model	[CPI-model-EDB-DPP3-final-determination-27-November-2019.xlsx]Output'!$H$8:$N$8		

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259	5.3.10(5)(c)	in respect of later quarters, the forecast last applying under paragraph (b), adjusted such that an equal increment or decrement made to that forecast for each of the following three years results in the forecast for the last of those years being equal to the target midpoint for the change in headline CPI set out in the Monetary Policy Statement referred to in paragraph (b).	Financial Model	[CPI-model-EDB-DPP3-final-determination-27-November-2019.xlsx]Output'!$H$8:$N$8		
260	5.3.11	**Forecast value of commissioned assets**	Financial/Model report	Chapter 7	Section 7.3	
261	5.3.11(1)	'Forecast value of commissioned asset', in relation to an asset for which capital expenditure is included in forecast capital expenditure (including an asset in respect of which capital contributions are or are forecast to be received, or a vested asset) means the forecast cost of the asset to an EDB determined by applying GAAP to the asset as on its forecast commissioning date, except that, subject to subclauses (2) and (3), the cost of-	Financial/Model report	Chapter 7	Section 7.3.1	
262	5.3.11(1)(a)	an intangible asset, unless it is-	Financial/Model report	Chapter 7	Section 7.3.1	
263	5.3.11(1)(a)(i)	a finance lease; or	Financial/Model report	Chapter 7	Section 7.3.1	
264	5.3.11(1)(a)(ii)	an identifiable non-monetary asset,	Financial/Model report	Chapter 7	Section 7.3.1	
265		is nil;	Financial/Model report	Chapter 7	Section 7.3.1	
266	5.3.11(1)(b)	an easement, is limited to its forecast market value as on its forecast commissioning date as determined by a valuer;	Financial/Model report	Chapter 7	Section 7.3.1	
267	5.3.11(1)(c)	easement land is nil;	Financial/Model report	Chapter 7	Section 7.3.1	
268	5.3.11(1)(d)	a network spare-	Financial/Model report	Chapter 7	Section 7.3.1	
269	5.3.11(1)(d)(i)	which is not required, in light of the historical reliability and number of the assets it is held to replace; or	Financial/Model report	Chapter 7	Section 7.3.1	
270	5.3.11(1)(d)(ii)	whose cost is not treated as the cost of an asset under GAAP, whether wholly or in part,	Financial/Model report	Chapter 7	Section 7.3.1	
271		is nil;	Financial/Model report	Chapter 7	Section 7.3.1	
272	5.3.11(1)(e)	an asset-	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - our expenditure forecasts do not include any forecast acquisitions from other regulated entities that have been used by that regulated supplier in the supply of regulated goods or services
273	5.3.11(1)(e)(i)	to be acquired from another regulated supplier; and	Financial/Model report	Chapter 7	Section 7.3.1	
274	5.3.11(1)(e)(ii)	used by that regulated supplier in the supply of regulated goods or services,	Financial/Model report	Chapter 7	Section 7.3.1	
275		is limited to its value determined in accordance with input methodologies applicable to the services supplied by that other regulated supplier as on the forecast commissioning date;	Financial/Model report	Chapter 7	Section 7.3.1	
276	5.3.11(1)(f)	an asset that was previously used by an EDB in its supply of other regulated services is limited to its value determined in accordance with input methodologies applicable to those other regulated services as on the day before the forecast commissioning date;	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - we do not provide any other regulated services
277	5.3.11(1)(g)	an asset or assets, or components of assets, forecast to be acquired in a related party transaction, and forecast to be commissioned during any disclosure year of the CPP regulatory period other than assets to which paragraphs (e) or (f) apply, is the forecast cost specified in subclause (7);	Financial/Model report	Chapter 7	Section 7.3.1	
278	5.3.11(1)(h)	an asset in respect of which capital contributions are or are forecast to be received where such contributions are not taken into account when applying GAAP, is the cost of the asset by applying GAAP reduced by the amount of the capital contributions;	Financial/Model report	Chapter 7	Section 7.3.1	
279	5.3.11(1)(i)	a vested asset in respect of which its fair value is or would be treated as its cost under GAAP, must exclude any amount of the fair value of the asset determined under GAAP that exceeds the amount of consideration provided or forecast to be provided by the EDB;	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - our forecast does not include any value for vested assets that exceeds the amount of consideration provided or forecast to be provided
280	5.3.11(1)(j)	for the purpose of subclause (a)(i), a finance lease excludes the value of any asset for which annual charges are a recoverable cost under clause 3.1.3(1)(c); and	Financial/Model report	Chapter 7	Section 7.3.1	
281	5.3.11(1)(k)	An asset part of the cost of which has been or has been forecast to be recovered as a recoverable cost by being drawn down by an EDB from its innovation project allowance, is the cost or the forecast cost of the asset by applying GAAP, reduced by the amount of the recoverable cost or forecast recoverable cost that the Commission has specified as capex in its approval of the draw down from the innovation project allowance.	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - we have not forecast any innovation project allowance

282	5.3.11(2)	Where an asset forecast to be commissioned is forecast to be used to supply either or both an other regulated service and an unregulated service, its regulated service asset value borne by regulated services, in aggregate-	Financial/Model report	Chapter 7	Section 7.3.3	Not applicable - all assets forecast to be commissioned are directly attributable
283	5.3.11(2)(a)	may not exceed the total value of the asset that would be allocated to regulated services, in aggregate, using ACAM; and	N / A			
284	5.3.11(2)(b)	must be based only on forecast changes in the EDB's business of supplying electricity distribution services.	N / A			
285	5.3.11(3)	When applying GAAP for the purposes of subclause (1), the cost of financing is-	Financial/Model report	Chapter 7	Section 7.3.6	
286	5.3.11(3)(a)	applicable only in respect of the period commencing on the date the asset becomes or is forecast to become a works under construction and terminating on its commissioning date or forecast commissioning date, as the case may be; and	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$M$111:$S$111		
287	5.3.11(3)(b)	calculated using a rate not greater than the EDB's forecast weighted average of borrowing costs for each applicable disclosure year.	Financial/Model report	Chapter 7	Section 7.3.6	
288	5.3.11(4)	For the purposes of subclause (3)(b), the 'forecast weighted average of borrowing costs' is calculated for a disclosure year using principles set out in GAAP, taking into account:	Financial/Model report	Chapter 7	Section 7.3.6	
289	5.3.11(4)(a)	the cost of financing rate is the forecast weighted average of the costs applicable to borrowings in respect of capex that are forecast to be outstanding during the disclosure year;	Financial/Model report	Chapter 7	Section 7.3.6	
290	5.3.11(4)(b)	the total costs applicable to borrowings outstanding as used in calculating the weighted average must include costs of borrowings made or forecast to be made specifically for the purpose of any particular –	Financial/Model report	Chapter 7	Section 7.3.6	
291	5.3.11(4)(b)(i)	capex projects; or	Financial/Model report	Chapter 7	Section 7.3.6	
292	5.3.11(4)(b)(ii)	capex programmes; and	Financial/Model report	Chapter 7	Section 7.3.6	
293	5.3.11(4)(c)	the amount of borrowing costs forecast to be capitalised during the disclosure year must not exceed the amount of borrowing costs forecast to be incurred during the disclosure year;	Financial/Model report	Chapter 7	Section 7.3.6	
294	5.3.11(4)(d)	where a capital contribution is received by an EDB, the relevant asset will become works under construction for the purposes of calculating the cost of financing;	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no expenditure on capital contributions is forecast to incur financing costs
295	5.3.11(4)(e)	subject to subclause (i), a capital contribution will reduce the cost of works under construction for the purpose of the calculation of the finance cost, even if the resulting value of works under construction is negative;	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no expenditure on capital contributions is forecast to incur financing costs
296	5.3.11(4)(f)	subject to subclause (g), where the value of works under construction will be negative in accordance with subclause (e), the cost of financing for the period ending on the forecast commissioning date will be negative;	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no expenditure on capital contributions is forecast to incur financing costs
297	5.3.11(4)(g)	where the cost of financing an asset which is works under construction is negative under subclause (f), it will reduce the forecast value of the relevant asset or assets by that negative amount where such a reduction is not otherwise made under GAAP;	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no expenditure on capital contributions is forecast to incur financing costs
298	5.3.11(4)(h)	for the purpose of subclause (d), works under construction includes assets that are forecast to be enhanced or acquired; and	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - expenditure on capital contributions is forecast to incur financing costs
299	5.3.11(4)(i)	where the cost of financing is forecast to be derived as income in relation to works under construction and is-	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no income is forecast from assets while they are in works under construction
300	5.3.11(4)(i)(i)	negative; and	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no income is forecast from assets while they are in works under construction
301	5.3.11(4)(i)(ii)	included in regulatory income under an ID determination,	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no income is forecast from assets while they are in works under construction

302		it will not reduce the forecast value of the relevant asset or assets where such reduction would not otherwise be made under GAAP.	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no income is forecast from assets while they are in works under construction
303	5.3.11(5)	For the avoidance of doubt-				
304	5.3.11(5)(a)	revenue derived or forecast to be derived in relation to works under construction that is not included in regulatory income under an ID determination reduces the cost of an asset by the amount of the revenue where such reduction is not otherwise made under GAAP; and	Financial/Model report	Chapter 7	Section 7.3.6	Not applicable - no income is forecast from assets while they are in works under construction
305	5.3.11(5)(b)	where expenditure on an asset which forms or is forecast to form part of the cost of that asset under GAAP is incurred or forecast to be incurred by an EDB after that asset is commissioned or forecast to be commissioned, such expenditure is treated as relating to a separate asset.	Financial/Model report	Chapter 7	Section 7.3	
306	5.3.11(6)	In this clause, 'forecast capital expenditure' means, in relation to a CPP proposal-	Financial/Model report	Chapter 7	Section 7.3.1	
307	5.3.11(6)(a)	that has not been assessed by the Commission, the amount of capital expenditure for the relevant disclosure year of the next period included by the CPP applicant in its capex forecast; and	Financial/Model report	Chapter 7	Section 7.3.1	
308	5.3.11(6)(b)	undergoing assessment by the Commission, the amount of capital expenditure determined for the relevant disclosure year of the next period by the Commission after assessment of the amount in paragraph (a) against the expenditure objective.	Financial/Model report	Chapter 7	Section 7.3.1	
309	5.3.11(7)	For the purpose of paragraph 5.3.11(1)(g), the forecast cost of any commissioned assets, or components of assets, forecast to be acquired in a related party transaction, must be set on the basis that–	Financial/Model report	Chapters 6, 7	Sections 6.4, 7.3.1, 7.7	
310	5.3.11(7)(a)	the forecast cost of a commissioned asset or a component of a commissioned asset forecast to be acquired in the related party transaction must be given a value not greater than if that transaction had the terms of an arm's-length transaction;	Financial/Model report	Chapters 6, 7	Sections 6.4, 7.3.1, 7.7	
311	5.3.11(7)(b)	an objective and independent measure must be used in determining the terms of an arm's-length transaction for the purpose of paragraph (a); and	Financial/Model report	Chapters 6, 7	Sections 6.4, 7.3.1, 7.7	
312	5.3.11(7)(c)	for the purpose of paragraph (a), where a forecast commissioned asset or a component of a commissioned asset is forecast to be acquired in the related party transaction, the forecast value that will qualify for recognition as the forecast cost of a commissioned asset or a component of a commissioned asset must not exceed the forecast amount expected to be charged to the EDB by the related party.	Financial/Model report	Chapters 6, 7	Sections 6.4, 7.3.1, 7.7	
313	5.3.11(8)	For the purpose of subclause (7)(a), a related party transaction will be treated as if it had the terms of an arm's-length transaction if the commissioned asset, or component of the commissioned asset, forecast to be acquired from a related party is valued at the forecast cost expected to be incurred by the related party, provided that this would-	Financial/Model report	Chapter 7	Section 7.7	Not applicable - as set out in section 7.7, arm's length value has already been supported on the basis that forecasts are either determined using a base-step-trend forecast approach or apply independently determined unit rates that represent market values
314	5.3.11(8)(a)	be fair and reasonable to the EDB; and	N / A			
315	5.3.11(8)(b)	be substantially the same as any such forecast cost expected to be incurred by the related party in providing the same type of asset to third parties.	N / A			
316	5.3.12	**Works under construction**	Financial/Model report	Chapter 7	Section 7.3.7	
317	5.3.12(1)	Opening works under construction means, in respect of-	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$15:$S$15		
318	5.3.12(1)(a)	the first disclosure year of the next period where that year is consecutive to a disclosure year in respect of which disclosure pursuant to an ID determination-				
319	5.3.12(1)(a)(i)	has not been made, initial works under construction; and				
320	5.3.12(1)(a)(ii)	has been made, the value of works under construction last disclosed in accordance with the ID determination to the extent that it is intended to be included in a closing RAB value; and				

321	5.3.12(1)(b)	any year other than the first disclosure year of the next period, closing works under construction of the preceding disclosure year.				
322	5.3.12(2)	For the purpose of subclause (1)(a)(i), 'initial works under construction' means expenditure incurred on works under construction as of the first day of the disclosure year in question, calculated in accordance with clause 5.3.11, modified in that references in that clause to "forecast commissioning date" are substituted with "forecast date that expenditure is incurred".				
323	5.3.12(3)	Closing works under construction is the amount determined in accordance with the formula-	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$18:$S$18		The works under construction roll forward excludes right-of-use assets. ROU assets are included in capital expenditure and commissioned assets in the same year.
324		opening works under construction + sum of capital expenditure - (sum of value of commissioned assets + sum of forecast value of commissioned assets),				
325		where-				
326	5.3.12(3)(a)	the sum of value of commissioned assets only includes values to the extent that they are included in closing RAB values disclosed pursuant to an ID determination; and				
327	5.3.12(3)(b)	the sum of forecast value of commissioned assets only includes values to the extent that they are included in the sum of closing RAB values provided pursuant to clause 5.4.11(b)(ii).				
328	**SECTION 3 Treatment of taxation**					
329	5.3.13	**Forecast regulatory tax allowance**	Financial/Model report	Chapter 8	Key points	
330	5.3.13(1)	Forecast regulatory tax allowance is, where forecast regulatory net taxable income is-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$17:$N$17		
331	5.3.13(1)(a)	nil or a positive number, the tax effect of forecast regulatory net taxable income; and				
332	5.3.13(1)(b)	a negative number, nil.				
333	5.3.13(2)	Regulatory net taxable income means regulatory taxable income less utilised tax losses.	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$15:$N$15		
334	5.3.13(3)	Regulatory taxable income is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$24:$N$24		
335		regulatory profit / (loss) before tax + permanent differences + regulatory tax adjustments.				
336	5.3.13(4)	Regulatory profit / (loss) before tax means the value determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$31:$N$31		
337		building blocks allowable revenue before tax - operating expenditure - total depreciation.				
338	5.3.14	**Tax losses**	Financial/Model report	Chapter 8	Section 8.4	Not applicable - there are no opening or current period tax losses and we have not forecast any tax loses during the forecast period
339	5.3.14(1)	Utilised tax losses means opening tax losses, subject to subclause (2).	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$37:$N$37		
340	5.3.14(2)	For the purpose of subclause (1), utilised tax losses may not exceed regulatory taxable income.				
341	5.3.14(3)	Opening tax losses in relation to-				
342	5.3.14(3)(a)	the first disclosure year of the next period, is nil, subject to subclause (4); and				
343	5.3.14(3)(b)	subsequent disclosure years of the next period, is closing tax losses for the preceding disclosure year.				
344	5.3.14(4)	For the purpose of subclause (3)(a), if the Commission is satisfied that an EDB will incur forecast tax losses, opening tax losses is the amount of losses in respect of which the Commission is satisfied.				

345	5.3.14(5)	For the purpose of subclause (3)(b), 'closing tax losses' means the amount determined in accordance with the following formula, in which each term is an absolute value:	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$38:$N$38		
346		opening tax losses + current period tax losses - utilised tax losses.				
347	5.3.14(6)	In this clause, 'current period tax losses' is, where regulatory taxable income is-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$36:$N$36		
348	5.3.14(6)(a)	nil or a positive number, nil; and				
349	5.3.14(6)(b)	a negative number, regulatory taxable income.				
350	5.3.15	**Permanent differences**	Financial/Model report	Chapter 8	Section 8.2	
351	5.3.15(1)	Permanent differences is the amount determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$45:$N$45		
352		positive permanent differences - discretionary discounts and customer rebates - negative permanent differences.				
353	5.3.15(2)	For the purpose of subclause (1), 'positive permanent differences' means, subject to subclause (3), the sum of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$33:$S$33		
354	5.3.15(2)(a)	all amounts of income-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$27:$S$27		
355	5.3.15(2)(a)(i)	treated as taxable were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
356	5.3.15(2)(a)(ii)	not included as amounts of income in determining regulatory profit / (loss) before tax; and				
357	5.3.15(2)(b)	all amounts of expenditure or loss-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$31:$S$31		
358	5.3.15(2)(b)(i)	included as amounts of expenditure or loss in determining regulatory profit / (loss) before tax; and				
359	5.3.15(2)(b)(ii)	not treated as deductions were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services,				
360		if the difference in treatment of amounts of-				
361	5.3.15(2)(c)	income under paragraph (a)(i) and paragraph (a)(ii); or				
362	5.3.15(2)(d)	expenditure or loss under paragraph (b)(i) and paragraph (b)(ii),				
363		is a difference that is not -				
364	5.3.15(2)(e)	a reversal or partial reversal of a difference for a prior disclosure year; and				
365	5.3.15(2)(f)	forecast to reverse in a subsequent disclosure year.				
366	5.3.15(3)	For the purpose of subclause (2), positive permanent differences excludes any amounts that are-				
367	5.3.15(3)(a)	amortisation of initial differences in asset values; or				
368	5.3.15(3)(b)	amortisation of revaluations.				
369	5.3.15(4)	For the purpose of subclause (1), 'negative permanent differences' means, subject to subclause (5), the sum of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$45:$S$45		
370	5.3.15(4)(a)	all amounts of income-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$39:$S$39		
371	5.3.15(4)(a)(i)	included as amounts of income in determining regulatory profit / (loss) before tax; and				

372	5.3.15(4)(a)(ii)	not treated as taxable were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
373	5.3.15(4)(b)	all amounts of expenditure or loss-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$43:$S$43		
374	5.3.15(4)(b)(i)	treated as deductions were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
375	5.3.15(4)(b)(ii)	not included as amounts of expenditure or loss in determining regulatory profit / (loss) before tax,				
376		if there are differences between the values in-				
377	5.3.15(4)(c)	paragraph (a)(i) and paragraph (a)(ii); and				
378	5.3.15(4)(d)	paragraph (b)(i) and paragraph (b)(ii),				
379	5.3.15(4)	and such differences are not-				
380	5.3.15(4)(e)	the reversal of a difference in a prior disclosure year; and				
381	5.3.15(4)(f)	forecast to reverse in a subsequent disclosure year.				
382	5.3.15(5)	For the purpose of subclause (4), negative permanent differences excludes any amounts that are-				
383	5.3.15(5)(a)	discretionary discounts and customer rebates;				
384	5.3.15(5)(b)	expenditure or loss determined in accordance with the tax rules that is-				
385	5.3.15(5)(b)(i)	interest; or				
386	5.3.15(5)(b)(ii)	forecast to be incurred in borrowing money; and				
387	5.3.15(5)(c)	any-				
388	5.3.15(5)(c)(i)	tax losses; and				
389	5.3.15(5)(c)(ii)	subvention payment made or received by an EDB.				
390	5.3.16	**Regulatory tax adjustments**	Financial/Model report	Chapter 8	Section 8.3	
391	5.3.16(1)	Regulatory tax adjustments are determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$67:$N$67		
392		amortisation of initial differences in asset values + amortisation of revaluations - notional deductible interest.				
393	5.3.16(2)	For the purpose of subclause (1), 'notional deductible interest' means the amount determined in accordance with the formula–	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$65:$N$65		
394		(((regulatory investment value + RAB proportionate investment) x leverage x cost of debt) + term credit spread differential allowance)				
395		÷				
396		√(1 + cost of debt).				
397	5.3.16(3)	For the purpose of subclause (2), 'RAB proportionate investment' means the sum of the proportionate value of each asset forecast to be commissioned less the sum of the proportionate value of each disposed asset.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$28:$S$28		
398	5.3.16(4)	For the purpose of subclause (3), 'proportionate value' means for-				
399	5.3.16(4)(a)	an asset forecast to be commissioned, its forecast value of commissioned asset multiplied by the proportion of that disclosure year in question from the forecast commissioning date to the end of that disclosure year out of the whole disclosure year; and	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$26:$S$26		
400	5.3.16(4)(b)	a disposed asset, its opening RAB value multiplied by the proportion of that disclosure year from the date of sale or transfer to the end of that disclosure year out of the whole disclosure year.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$27:$S$27		
401	5.3.17	**Amortisation of initial differences in asset values**	Financial/Model report	Chapter 8	Section 8.3.1	As noted below, the Commission has granted an exemption to clause 5.4.22(1) to allow us to disclose the total opening unamortised balance rather than disclosing the asset values by asset category. As per IM clause 5.3.17, the annual roll-forward is derived at an aggregate level, rather than being built up from asset-level information.

402	5.3.17(1)	Amortisation of initial differences in asset values is, subject to subclause (4), determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$72:$N$72		
403		opening unamortised initial differences in asset values ÷ opening weighted average remaining useful life of relevant assets.				
404	5.3.17(2)	For the purpose of this clause, 'opening unamortised initial differences in asset values' means, in respect of-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$71:$N$71		
405	5.3.17(2)(a)	the disclosure year 2010, initial differences in asset values; and				
406	5.3.17(2)(b)	each disclosure year thereafter, subject to subclause (4), closing unamortised initial difference in asset values for the preceding disclosure year.				
407	5.3.17(3)	For the purpose of subclause (2)(a), 'initial differences in asset values' means, subject to subclause (4), the sum of initial RAB values less the sum of regulatory tax asset values on the first day of the disclosure year 2010.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other' !$H$46:$L$46		For the purposes of the financial model, the opening balance of initial differences in asset values is disclosed from the start of RCP2 to the end of the CPP period
408	5.3.17(4)	For the purpose of subclause (1), 'opening weighted average remaining useful life of relevant assets' means	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other' !$H$45:$L$45		
409		q = a - b				
410		where:				
411		a = the 2010 weighted average remaining asset life of assets included in the initial RAB calculated by using initial RAB values as weightings				
412		b = disclosure year less 2010.				
413	5.3.17(5)	For the purpose of subclauses (1) and (2)-				
414	5.3.17(5)(a)	no account may be taken of unamortised initial differences in asset values of sold assets from the date of sale; and	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other' !$M$57:$S$57		
415	5.3.17(5)(b)	account must be taken of unamortised initial differences in asset values of acquired assets from the date of acquisition.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other' !$M$56:$S$56		
416	5.3.17(6)	For the purpose of subclause (2)(b), 'closing unamortised initial difference in asset values' is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$74:$N$74		
417		Opening unamortised initial differences in asset values - amortisation of initial difference in asset values				
418	5.3.18	**Amortisation of revaluations**	Financial/Model report	Chapter 8	Section 8.3.2	
419		Amortisation of revaluations in relation to an EDB for a disclosure year is calculated in accordance with the formula	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$54:$N$54		
420		total depreciation - adjusted depreciation.				
421	5.3.19	**Deferred tax**	Financial/Model report	Chapter 8	Section 8.6	
422	5.3.19(1)	Opening deferred tax means -	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$14:$N$14		
423	5.3.19(1)(a)	in respect of the disclosure year 2010, nil; and				
424	5.3.19(1)(b)	subject to paragraph (c), in respect of each disclosure year thereafter, closing deferred tax for the preceding disclosure year; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$12:$N$12		
425	5.3.19(1)(c)	in respect of each disclosure year after the disclosure year 2010, for assets for which there is no regulatory tax asset value, the opening deferred tax balance under GAAP for those assets at the date when those assets are forecast to be commissioned.".	Financial Model	]1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$13:$N$13		ROU assets have no RTAV. The deferred tax balance for these assets have been calculated in accordance with GAAP
426	5.3.19(2)	For the purpose of subclause (1)(b), 'closing deferred tax' is determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$30:$N$30		In addition, refer to Table 8.7 in Chapter 8 of the Financial/Model report

427		opening deferred tax + tax effect of temporary differences - tax effect of amortisation of initial difference in asset values + deferred tax balance relating to assets acquired in the disclosure year in question – deferred tax balance relating to assets disposed of in the disclosure year in question + cost allocation adjustment.				
428	5.3.19(3)	For the purpose of subclause (2), 'deferred tax balance relating to assets acquired in the disclosure year in question' means the amount of deferred tax associated with the assets acquired by the EDB from another regulated supplier, excluding the reversal of temporary adjustments arising as a consequence of the sale, as determined in accordance with input methodologies applicable to the regulated services that the assets in question were used to supply.	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$27:$N$27		Not applicable - no assets are forecast to be acquired from another regulated supplier
429	5.3.19(4)	For the avoidance of doubt, the amount referred to in subclause (3) must include proportionate adjustments for-				
430	5.3.19(4)(a)	the tax effect of temporary differences; and				
431	5.3.19(4)(b)	the amortisation of initial differences in asset values,				
432		up to the date the assets in question were acquired.				
433	5.3.19(5)	For the purpose of subclause (2), 'cost allocation adjustment' means the tax effect of the dollar value difference between the change in the sum of regulatory tax asset values on the last day of the disclosure year and the change in the sum of closing RAB values as a result only of applying-	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$28:$N$28		
434	5.3.19(5)(a)	the result of asset allocation ratios to the tax asset value in accordance with clause 5.3.21(1); and				
435	5.3.19(5)(b)	Clause 2.1.1 to the unallocated closing RAB value, where either or both clauses 5.3.6(1)(b)(ii) and 5.3.6(3) apply.				
436	5.3.19(6)	For the purpose of subclause (2), 'deferred tax balance relating to assets disposed of in the disclosure year in question' means the amount of deferred tax associated with the assets disposed of by the EDB and, where that deferred tax balance is a deferred tax liability, it must have a negative value.	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$18:$N$18		
437	5.3.20	**Temporary differences**	Financial/Model report	Chapter 8	Sections 8.6.1 - 8.6.2	
438	5.3.20(1)	Temporary differences is the amount determined in accordance with the formula-	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$26:$N$26		
439		depreciation temporary differences + positive temporary differences - negative temporary differences.				
440	5.3.20(2)	For the purpose of this clause, 'depreciation temporary differences' is adjusted depreciation less tax depreciation.	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$23:$N$23		In addition, refer to Section 8.6.1 in Chapter 8 of the Financial/Model report
441	5.3.20(3)	For the purpose of subclause (2) 'tax depreciation' is the sum of the amounts determined for all assets by application of the tax depreciation rules to the regulatory tax asset value of each asset.	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$22:$N$22		
442	5.3.20(4)	For the purpose of subclause (1), 'positive temporary differences' means the sum of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$67:$S$67		In addition, refer to Section 8.6.2 in Chapter 8 of the Financial/Model report
443	5.3.20(4)(a)	all amounts of income-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$64:$S$64		
444	5.3.20(4)(a)(i)	treated as taxable if the tax rules were applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
445	5.3.20(4)(a)(ii)	not included as amounts of income in determining regulatory profit / (loss) before tax; and				
446	5.3.20(4)(b)	all amounts of expenditure or loss-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$65:$S$66		

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447	5.3.20(4)(b)(i)	included as amounts of expenditure or loss in determining regulatory profit / (loss) before tax; and				
448	5.3.20(4)(b)(ii)	not treated as deductions were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services,				
449		less any amount that is depreciation temporary differences, if there are differences between the values in-				
450	5.3.20(4)(c)	paragraph (a)(i) and paragraph (a)(ii); and				
451	5.3.20(4)(d)	paragraph (b)(i) and paragraph (b)(ii),				
452		and such differences-				
453	5.3.20(4)(e)	are the reversal of a difference in a prior disclosure year; or				
454	5.3.20(4)(f)	are forecast to reverse in a subsequent disclosure year.				
455	5.3.20(5)	For the purpose of subclause (1), 'negative temporary differences' means the sum of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$81:$S$81		In addition, refer to Section 8.6.2 in Chapter 8 of the Financial/Model report
456	5.3.20(5)(a)	all amounts of income-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$L$73:$S$73		
457	5.3.20(5)(a)(i)	included as amounts of income in determining regulatory profit / (loss) before tax; and				
458	5.3.20(5)(a)(ii)	not treated as taxable were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
459	5.3.20(5)(b)	all amounts of expenditure or loss-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$L$77:$S$77		
460	5.3.20(5)(b)(i)	treated as deductions were the tax rules applied to determine income tax payable in respect of the EDB's supply of electricity distribution services; and				
461	5.3.20(5)(b)(ii)	not included as amounts of expenditure or loss in determining regulatory profit / (loss) before tax,				
462		less any amount that is depreciation temporary differences, if there are differences between the values in-				
463	5.3.20(5)(c)	paragraph (a)(i) and paragraph (a)(ii); and				
464	5.3.20(5)(d)	paragraph (b)(i) and paragraph (b)(ii),				
465		and such differences-				
466	5.3.20(5)(e)	are the reversal of a difference in a prior disclosure year; or				
467	5.3.20(5)(f)	are forecast to reverse in a subsequent disclosure year.				
468	5.3.21	**Regulatory tax asset value**	Financial/Model report	Chapter 8	Section 8.6.3	
469	5.3.21(1)	Regulatory tax asset value, in relation to an asset, means the value determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV' !$M$30:$S$30		For the purposes of the financial model, we have modelled the RTAV and the tax asset value of shared assets seperately. The RTAV of the shared assets can be calculated as the tax asset value for shared assets x result of the asset allocation ratio.
470		tax asset value x result of asset allocation ratio.				
471	5.3.21(2)	Tax asset value means, in respect of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV' !$M$41:$S$41		
472	5.3.21(2)(a)	an asset-				
473	5.3.21(2)(a)(i)	in the initial RAB where, in the disclosure year 2010, the sum of unallocated initial RAB values is less than the sum of the adjusted tax values of all assets in the initial RAB;				
474	5.3.21(2)(a)(ii)	acquired from a regulated supplier who used it to supply regulated goods or services; or				
475	5.3.21(2)(a)(iii)	acquired or transferred from a related party,				
476		the value of the asset determined by applying the tax depreciation rules to its notional tax asset value; and				
477	5.3.21(2)(b)	any other asset, its forecast adjusted tax value.				
478	5.3.21(3)	'Notional tax asset value' means, for the purpose of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV' !$M$41:$S$41		

479	5.3.21(3)(a)	subclause (2)(a)(i), adjusted tax value of the asset in the disclosure year 2010 adjusted to account proportionately for the difference between the-				
480	5.3.21(3)(a)(i)	sum of the unallocated initial RAB values; and				
481	5.3.21(3)(a)(ii)	sum of the adjusted tax values,				
482		of all assets in the initial RAB;				
483	5.3.21(3)(b)	subclause (2)(a)(ii), value after applying the tax depreciation rules to the tax asset value (as 'tax asset value' is defined in the input methodologies applying to the regulated goods or services in question) in respect of the disclosure year in which the asset was acquired; and				
484	5.3.21(3)(c)	subclause (2)(a)(iii), value in respect of the disclosure year in which the asset was acquired or transferred that is-				
485	5.3.21(3)(c)(i)	consistent with the tax rules; and				
486	5.3.21(3)(c)(ii)	limited to its value of commissioned asset or, if relevant capital contributions are treated for tax purposes in accordance with section CG 8 of the Income Tax Act 2007 (or subsequent equivalent provisions), limited to the value of commissioned asset plus any taxed capital contributions applicable to the asset.				
487	5.3.21(4)	For the purpose of subclause (1), 'result of asset allocation ratio' means, where an asset or group of assets maintained under the tax rules-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$347:$S$347		
488	5.3.21(4)(a)	has a matching asset or group of assets maintained for the purpose of Part 2 Subpart 2, the value obtained in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$347:$S$347		
489		opening RAB value or sum of opening RAB values, as the case may be				
490		÷				
491		unallocated opening RAB value or sum of unallocated opening RAB values, as the case may be,				
492		applying the formula in respect of the asset or smallest group of assets maintained for the purpose of Part 2 Subpar 2 that has a matching asset or group of assets maintained under the tax rules; and				
493	5.3.21(4)(b)	does not have a matching asset or group of assets maintained for the purpose of Part 2 Subpar 2, the value of the asset allocated to the supply of electricity distribution services were clause 2.1.1 to apply to the asset or group of assets.				
494	**SECTION 4 Cost of Capital**					
495	5.3.22	Methodology for estimating the weighted average cost of capital	Financial/Model report	Chapter 5	Section 5.3	
496	5.3.22(1)	Where the Commission takes into account the cost of capital in making a CPP determination, the Commission will use the 67th percentile estimate of WACC that was used for the DPP applying at the start of the CPP regulatory period in accordance with clause 4.4.7(1).	Financial/Model report	Chapter 5	Section 5.3	
497	5.3.22(2)	Where there has been a WACC change, the cost of capital for the CPP is the DPP WACC referenced in clause 5.6.7(4)(a), which has effect in the remaining years of the CPP regulatory period.	Financial/Model report	Chapter 5	Section 5.3	There is not expected to be a WACC change during the 3 year CPP
498	5.3.23	**Methodology for estimating term credit spread differential**	Financial/Model report	Chapter 5	Section 5.1	Not applicable - no TCSD allowance is forecast
499	5.3.23(1)	'Term credit spread differential' is the amount determined for a qualifying supplier in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other'!$M$94:$S$94		
500		(A ÷ B) × C ×D,				
501		where-				
502	5.3.23(1)(a)	'A' is the sum of the term credit spread difference and debt issuance cost re-adjustment;	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other'!$M$80:$S$80		
503	5.3.23(1)(b)	'B' is the book value of the qualifying supplier's total interest-bearing debt as at the balance date of the supplier's financial statements audited and published in the disclosure year in question relate;	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other'!$M$88:$S$88		

504	5.3.23(1)(c)	'C' is leverage; and	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$90:$S$90		
505	5.3.23(1)(d)	'D' is, in relation to the qualifying supplier, the average of-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$92:$S$92		
506	5.3.23(1)(d)(i)	the sum of opening RAB values; and				
507	5.3.23(1)(d)(ii)	the sum of closing RAB values.				
508	5.3.23(2)	For the purpose of subclause (1)(a), 'debt issuance cost re-adjustment' is the amount determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$70:$S$70		
509		(0.01 ÷ original tenor of the qualifying debt - 0.002) × book value in New Zealand dollars of the qualifying debt at its date of issue,				
510		which amount, for the avoidance of doubt, will be a negative number.				
511	5.3.24	**Term credit spread difference**	Financial/Model report	Chapter 5	Section 5.1	Not applicable - no TCSD allowance is forecast
512	5.3.24(1)	'Term credit spread difference' is determined in accordance with the formula-	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$62:$S$62		
513		T × U,				
514		where-				
515	5.3.24(1)(a)	'T' is the amount determined in accordance with the formula-				
516		0.00075 × (original tenor of the qualifying debt – 5);				
517	5.3.24(1)(b)	'U' is the book value in New Zealand dollars of the qualifying debt at its date of issue.				
518	5.3.24(2)	For the purpose of this clause, where the qualifying debt is issued to a related party, 'original tenor of the qualifying debt' means the-				
519	5.3.24(2)(a)	tenor of the qualifying debt; or				
520	5.3.24(2)(b)	period from the qualifying debt's date of issue to the earliest date on which its repayment is or may be required,				
521		whichever is the shorter.				
522	5.3.25	**Interpretation of terms relating to term credit spread differential**	Financial/Model report	Chapter 5	Section 5.1	Not applicable - no TCSD allowance is forecast
523	5.3.25(1)	'Qualifying debt' means a line of debt-				
524	5.3.25(1)(a)	with an original tenor greater than 5 years; and				
525	5.3.25(1)(b)	issued by a qualifying supplier.				
526	5.3.25(2)	'Qualifying supplier' means a regulated supplier whose debt portfolio, as at the date of that supplier's most recently published audited financial statements, has a weighted average original tenor greater than 5 years.				
527	**SECTION 5 Alternative methodologies with equivalent effect**					
528	5.3.26	**Alternative methodologies with equivalent effect**	Application	Appendix V		Not applicable - We do not propose any AMWEEs in our CPP proposal
529	5.3.26(1)	A CPP applicant, in making a CPP application, may apply an alternative methodology to that specified for—	N / A	N / A	N / A	
530	5.3.26(1)(a)	cost allocation and asset valuation in Section 2;	N / A	N / A	N / A	
531	5.3.26(1)(b)	treatment of taxation in Section 3; or	N / A	N / A	N / A	
532	5.3.26(1)(c)	the estimation of term credit spread differentials in Section 4.	N / A	N / A	N / A	
533	5.3.26(2)	The Commission, in evaluating a CPP proposal and in determining a CPP for an EDB, may apply the alternative methodology elected by the CPP applicant.	N / A	N / A	N / A	
534	5.3.26(3)	An alternative methodology applied by either an EDB or the Commission in accordance with this clause must:	N / A	N / A	N / A	
535	5.3.26(3)(a)	produce an equivalent effect within the CPP regulatory period to the methodology that would otherwise apply; and	N / A	N / A	N / A	
536	5.3.26(3)(b)	not detract from the promotion of the purpose of Part 4 of the Act.	N / A	N / A	N / A	
537	**SUBPART 4 INFORMATION REQUIRED IN A CPP PROPOSAL**					
538	**SECTION 1 General Matters**					
539	5.4.1	**Application of this subpart**				
540	5.4.1(1)	Subject to subclause (2), a CPP proposal must contain, in all material respects, the information specified in this subpart.	Application	Chapter 4		

541	5.4.1(2)	For the purpose of subclause (1), where a CPP proposal is made in accordance with provisions in a DPP determination relating to the submission of CPP proposals in response to a catastrophic event, the information specified in clause 5.4.3 is not required.	Application	Appendix V		Not applicable - CPP not submitted in response to a catastrophic event
542	5.4.2	**Reasons for the proposal**				
543		A CPP proposal must contain a-				
544	5.4.2 (a)	detailed description of the CPP applicant's rationale for seeking a CPP; and	Application	Chapter 1	Section 1.2	
545	5.4.2 (b)	summary of the key evidence in the proposal supporting that rationale.	Application	Chapter 1	Section 1.2	
546	5.4.3	**Information regarding priority of proposal**				
547	5.4.3(1)	A CPP proposal must contain an explanation as to why the proposal deserves to be prioritised for assessment before other CPP proposals, were the Commission to exercise its prioritisation powers under s 53Z of the Act.	Application	Chapter 3, Appendix S, Appendix R	Section 3.5	The Commission has approved an exemption from this requirement in its approval letter dated 5 June 2020.
548	5.4.3(2)	For the purpose of subclause (1), a CPP applicant must address the prioritisation criteria specified in paragraphs (b) and (c) of s 53Z(3) of the Act, viz.-	N / A			
549	5.4.3(2)(a)	urgency of any proposed additional investment (compared to historic rates of investment) required to meet consumer requirements on quality, in accordance with subclause (3); and	N / A			
550	5.4.3(2)(b)	materiality of the proposal relative to the size and revenues of the applicant in accordance with subclause (4).	N / A			
551	5.4.3(3)	For the purpose of subclause (2)(a), the CPP applicant must explain-	N / A			
552	5.4.3(3)(a)	how any proposed investment-	N / A			
553	5.4.3(3)(a)(i)	compares with historic rates of investment; and	N / A			
554	5.4.3(3)(a)(ii)	relates to meeting consumer requirements on quality; and	N / A			
555	5.4.3(3)(b)	the optimal timing of any proposed investment, including any timeframes that would apply to the process of undertaking that proposed investment.	N / A			
556	5.4.3(4)	For the purpose of subclause (2)(b), the CPP applicant must-	N / A			
557	5.4.3(4)(a)	explain the current size of its business and how the proposed CPP would affect the size of its business; and	N / A			
558	5.4.3(4)(b)	describe its revenue under the DPP and explain how its revenue under the proposed CPP would differ, if at all, from that revenue.	N / A			
559	5.4.4	**Duration of regulatory period**	N / A			
560		Where a CPP applicant seeks a CPP of 3 years' or 4 years' duration-	Application	Chapter 4	Section 4.1	
561	5.4.4(a)	the duration of the CPP sought must be stated in the CPP proposal; and	Application	Chapter 4	Section 4.1	
562	5.4.4(b)	the CPP proposal must contain an explanation as to why that duration better meets the purpose of Part 4 of the Act than 5 years.	Application	Chapter 4	Section 4.1	
563	**SECTION 2 Information regarding quality**					
564	5.4.5	**Information on proposed quality standard variation**				
565		Where a CPP applicant seeks a quality standard variation as part of a CPP proposal, the CPP proposal must contain the following information:				
566	5.4.5(a)	The different values of either or both of-	Application	Appendix L	Section L.7	
567	5.4.5(a)(i)	the parameters relating quality standards, including any boundary value;	Application	Appendix L	Section L.7	
568	5.4.5(a)(ii)	the parameters relating to any incentives for the EDB to maintain or improve its quality of supply;	Application	Appendix L	Section L.7	
569		to those which would be determined in accordance with the methodology as specified in the DPP determination;	Application	Appendix L	Section L.7	
570	5.4.5(b)	an explanation of the reasons for the proposed quality standard variation;	Application	Appendix L	Section L.7	
571	5.4.5(c)	demonstration of the extent to which the quality standard variation better reflects the realistically achievable performance of the EDB over the CPP regulatory period based on either or both of-	Application	Appendix L		
572	5.4.5(c)(i)	statistical analysis of past SAIDI and SAIFI performance; and	Application	Appendix L	Section L.2	
573	5.4.5(c)(ii)	the level of investment provided for in proposed maximum allowable revenue before tax; and	Application	Appendix L	Section L.11	

574	5.4.5(d)	demonstration of the estimated effect of the proposed quality standard variation by use of historic data, by contrast with the quality standards specified in the DPP determination.	Application	Appendix L	Section L.7	
575	**SECTION 3 Price path information**					
576	5.4.6	**Interpretation**				
577	5.4.6(1)	In this section, the meanings of defined terms that are values or amounts to be determined by the Commission when making a CPP determination are modified to mean the values or amounts proposed by the CPP applicant, subject to any other provision to the contrary.				
578	5.4.6(2)	Any values and amounts used by a CPP applicant to determine the quantum of allowances, amounts, sums or values required by this section must be consistent with other information provided in accordance with this part.				
579	5.4.7	**Proposed building blocks allowable revenue**	Application Financial/Model report	Chapter 4 Chapter 5	Section 4.2	
580	5.4.7(1)	A CPP proposal must contain amounts for-				
581	5.4.7(1)(a)	building blocks allowable revenue before tax for each disclosure year of the next period; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$H$15:$N$15		
582	5.4.7(1)(b)	building blocks allowable revenue after tax for each disclosure year of the next period.	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$H$17:$N$17		
583	5.4.7(2)	Subject to subclause (4), a CPP proposal must contain all data, information, calculations and assumptions used to determine the amounts required by subclause (1), including but not limited to-	Application	Chapter 4	Section 4.2	
584	5.4.7(2)(a)	forecasts of-				
585	5.4.7(2)(a)(i)	regulatory investment value;	Financial Model	[1. CPP Financial Model vProposal.xlsm]BBARx'!$H$49:$N$49		
586	5.4.7(2)(a)(ii)	total value of commissioned assets determined in accordance with clause 5.3.2(3);	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$17:$N$17		
587	5.4.7(2)(a)(iii)	total depreciation; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$14:$N$14		
588	5.4.7(2)(a)(iv)	total revaluation;	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$16:$N$16		
589	5.4.7(2)(b)	all data, information, calculations and assumptions used to derive amounts or forecasts of TFVCA, PVVCA, TF, and TFrev determined in accordance with clause 5.3.2(4);	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Other '!$M$14:$S$17		
590	5.4.7(2)(c)	forecast operating expenditure; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$27:$N$27		
591	5.4.7(2)(d)	any proposed term credit spread differential allowance.	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$21:$N$21		
592	5.4.7(3)	All calculations, values and amounts required by this clause must be presented in a spreadsheet which -				
593	5.4.7(3)(a)	clearly demonstrates how building blocks allowable revenue before tax and building blocks allowable revenue after tax for each disclosure year of the next period have been derived using the formulae specified in clauses 5.3.2 and 5.3.3; and	Financial Model	Included within '[1. CPP Financial Model vProposal.xlsm]BBARx'		
594	5.4.7(3)(b)	where data has been computed or derived from other values on the spreadsheet through the use of formulae, makes the underlying formulae accessible.	Financial Model			The model has been submitted with all formulas visible
595	5.4.7(4)	Where the information specified in subclause (2) is included in a CPP proposal in a spreadsheet format-				

596	5.4.7(4)(a)	the information must be cross-referenced in the text of the CPP proposal document; and	Application	Chapter 4	Section 4.2	
597	5.4.7(4)(b)	the spreadsheet(s) must-				
598	5.4.7(4)(b)(i)	provide cross-references to any CPP information requirement input methodology that the spreadsheet satisfies;	Application Financial Model	Appendix T		This requirement is met using this compliance checklist (Appendix T of the Application). In addition, the Financial Model provides cross-references to the IM requirements
599	5.4.7(4)(b)(ii)	use terms and labels, consistent with the terminology in the input methodologies;	Financial Model			The Financial Model uses terms and labels consistent with the terminology in the input methodologies
600	5.4.7(4)(b)(iii)	identify and explain the source inputs, and outputs, of each spreadsheet;	Financial Model			Standard model structure is adopted in the CPP Financial Model
601	5.4.7(4)(b)(iv)	produce all of the intermediate outputs, as set out in Part 5, Subpart 3 and Part 5, Subpart 4; and	Financial Model			The Financial Model produces all of the intermediate outputs, as set out in Part 5, Subparts 3 and 4
602	5.4.7(4)(b)(v)	demonstrate links and interdependencies between source inputs, intermediate calculations and outputs.	Financial Model			The Financial Model demonstrates links and interdependencies between source inputs, intermediate calculations and outputs
603	5.4.8	**Maximum Allowable Revenues**	Financial/Model report	Chapter 4		
604	5.4.8(1)	A CPP proposal must contain amounts for-				
605	5.4.8(1)(a)	maximum allowable revenue before tax for each disclosure year of the CPP regulatory period; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$J$19:$N$19		
606	5.4.8(1)(b)	maximum allowable revenue after tax for each disclosure year of the CPP regulatory period.	Financial Model	[1. CPP Financial Model vProposal.xlsm]General '!$J$21:$N$21		
607	5.4.8(2)	For the purpose of subclauses (1)(a) and (1)(b), the CPP applicant must -				
608	5.4.8(2)(a)	apply an X factor; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]MARx '!$K$19:$N$19		In addition, refer to Section 4.3.2 of Chapter 4 in the Financial/Model Report
609	5.4.8(2)(b)	state the value of the X factor.	Financial Model	(0)		In addition, refer to Section 4.3.2 of Chapter 4 in the Financial/Model Report
610	5.4.8(3)	For the purpose of subclause (2) the X factor is that defined in the CPP applicant's DPP determination, subject to subclause (4).	Financial/Model report Application	Chapter 4 Chapter 4	Section 4.3.2 Section 4.3	
611	5.4.8(4)	For the purpose of subclause (3), a different X factor or factors may be used, provided that the CPP proposal contains an explanation and supporting evidence as to why that would better meet the purpose of Part 4 of the Act.	Financial/Model report Application	Chapter 4 Chapter 4	Section 4.3.2 Section 4.3	
612	5.4.8(5)	All calculations and values required by this clause must be presented in a spreadsheet format which clearly demonstrates how maximum allowable revenue before tax and maximum allowable revenue after tax for each disclosure year of the CPP regulatory period have been derived from building blocks allowable revenue after tax and the variables in clause 5.4.7.	Financial Model	Included within '[1. CPP Financial Model vProposal.xlsm]MARx '		
613	5.4.8(6)	For the purpose of subclause (5), the spreadsheet must be provided in a format that-	Financial Model	Included within '[1. CPP Financial Model vProposal.xlsm]MARx '		
614	5.4.8(6)(a)	shows clearly how the values required by subclause (1) were derived in accordance with the formulae specified in clauses 5.3.2 to 5.3.4; and				
615	5.4.8(6)(b)	where data has been computed or derived from other values on the spreadsheet through the use of formulae, makes the underlying formulae accessible.				
616	**SECTION 4 Cost allocation information**		**N / A**			
617	5.4.9	**Cost allocation information**	Financial/Model report Application	Chapter 6 Chapter 4	Section 6.1 Section 4.4	
618	5.4.9(1)	Where a CPP applicant-				
619	5.4.9(1)(a)	makes allocations of operating costs not directly attributable pursuant to clause 5.3.5(1); or	Application	Chapter 4, Appendix N	Section 4.4	
620	5.4.9(1)(b)	determines opening RAB values pursuant to clause 5.3.6(1)(b)(ii),	Application	Chapter 4, Appendix N	Section 4.4	

621		the CPP proposal must contain the information specified in subclause (2).	Application	Chapter 4, Appendix N	Section 4.4	
622	5.4.9(2)	For the purpose of subclause (1), the information is that specified in the applicable tables in Schedule B, subject to subclause (4), which tables comprise-	Application	Chapter 4, Appendix N	Section 4.4	
623	5.4.9(2)(i)	Table 1: Allocation of asset values;	Application	Chapter 4, Appendix N	Section 4.4	
624	5.4.9(2)(ii)	Table 2: Report supporting allocations of asset values (non-public);	Application	Chapter 4, Appendix N	Section 4.4	
625	5.4.9(2)(iii)	Table 3: Allocation of operating costs;	Application	Chapter 4, Appendix N	Section 4.4	
626	5.4.9(2)(iv)	Table 4: Report supporting allocation of operating costs (non-public); and	Application	Chapter 4, Appendix N	Section 4.4	
627	5.4.9(2)(v)	Table 5: Rationale for selecting proxy allocator.	Application	Chapter 4, Appendix N	Section 4.4	Not applicable - only causal allocators are applied
628	5.4.9(3)	Subject to subclause (7), in respect of-	Financial/Model report	Chapter 7	Section 7.2.1	Not applicable - There are no forecast asset sales that meet the definition of 5.3.5(2) or 5.3.6(4)
629	5.4.9(3)(a)	operating costs not directly attributable allocated to electricity distribution services in accordance with clause 5.3.5(2); or	N / A			
630	5.4.9(3)(b)	closing RAB values determined in accordance with clause 5.3.6(4),	N / A			
631		the CPP proposal must contain the information specified in Schedule C, subject to subclause (4), which tables comprise-	N / A			
632	5.4.9(3)(c)	Table 1: Revised allocation of regulated asset values;	N / A			
633	5.4.9(3)(d)	Table 2: Report supporting revised allocations of asset values (non-public);	N / A			
634	5.4.9(3)(e)	Table 3: Revised allocation of operating costs; and	N / A			
635	5.4.9(3)(f)	Table 4: Report supporting revised allocation of operating costs (non-public); and	N / A			
636	5.4.9(3)(g)	Table 5: Rationale for selecting proxy allocator.	N / A			
637	5.4.9(4)	For the purpose of this clause-	Financial Model	Included within '[2. Supporting Model - Other vProposal.xlsx]' – Schedule B tables		
638	5.4.9(4)(a)	the information specified in the tables of the schedules referred to must be provided on spreadsheets;	Financial Model	Included within '[3. Supporting Model - Expenditure vProposal.xlsx]' – Schedule E tables		
639	5.4.9(4)(b)	where data has been computed or derived from other values on the spreadsheet through the use of formulae, all underlying formulae must be accessible;	Financial Model			All underlying formulae are accessible.
640	5.4.9(4)(c)	the information specified in Table 2 and Table 4 of Schedule B and Table 2 and Table 4 of Schedule C may be provided by way of non-public disclosure to the Commission; and				
641	5.4.9(4)(d)	the information in Schedule B must be provided-	Financial/Model report Application	Chapter 6 Appendix S & Appendix N	Section 6.1.2	As set out in Section 6.1 of the Financial Model Information Report, the Commission has granted a modification to this requirement so that our CPP proposal provides: • for the Schedule B information that relates to asset allocations, the information for RY19 instead of RY20; and • for the Schedule B information that relates to operational expenditure allocations, the information for RY19 as disclosed and forecast information for each of RY20 to RY26. We will provide actual RY20 information as soon as possible, and no later than 1 September 2020. As set out in Section 6.1.2 of the Financial Model Information Report, we also confirm that the allocation methodology used to forecast closing RAB value and forecast operating expenditure for RY20 will be the same as the allocation methodology used for the closing RAB value and operating expenditure for RY19.

642	5.4.9(4)(d)(i)	for the disclosure year prior to submitting the CPP proposal if it has not been disclosed in accordance with an ID determination; and	Financial/Model report Application	Chapter 6 Appendix S & Appendix N	Section 6.1.2	Refer to comment above in relation to clause 5.4.9(4)(d).
643	5.4.9(4)(d)(ii)	for the next period where a value in units in an allocator metric has been changed by at least 5% from the value used in the disclosure year referred to in (i).	Financial/Model report Application	Chapter 6 Appendix S & Appendix N	Section 6.1.2	Refer to comment above in relation to clause 5.4.9(4)(d).
644	5.4.9(5)	Where the CPP applicant has used a proxy cost allocator to provide the information specified in subclauses (2) or (3), the CPP applicant must explain in the CPP proposal, for each proxy cost allocator used-	Financial/Model report	Chapter 7	Section 7.2	Not applicable - only causal allocators are applied
645	5.4.9(5)(a)	why a causal relationship cannot be established; and	N / A			Not applicable - only causal allocators are applied
646	5.4.9(5)(b)	the rationale for the quantifiable measure used for that proxy cost allocator.	N / A			Not applicable - only causal allocators are applied
647	5.4.9(6)	Where the CPP applicant has used a proxy asset allocator to provide the information specified in subclauses (2) or (3), the CPP applicant must explain in the CPP proposal, for each proxy asset allocator used-	N / A			Not applicable - only causal allocators are applied
648	5.4.9(6)(a)	why a causal relationship cannot be established; and	N / A			Not applicable - only causal allocators are applied
649	5.4.9(6)(b)	the rationale for the quantifiable measure used for that proxy cost allocator.	N / A			Not applicable - only causal allocators are applied
650	5.4.9(7)	The information in Schedule C is not required where the value of the assets to be sold as specified in clause 5.3.6(4) is less than 5% of the unallocated closing RAB value for the last disclosure year of the assessment period.	N / A			Not applicable - there are no forecast asset sales the meet the definition of 5.3.6(4)
651	5.4.10	**Certification requirements**				
652	5.4.10(1)	Where any arm's-length deduction was applied for the purpose of this Section, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in the following terms, where words in bold bear the meanings specified in this determination:	Application	Appendix V		Not applicable - no arm's length deduction was applied for the purpose of this section
653		"I, [insert name], **director** of [insert name of Supplier of **services** regulated under Part 4 of the Commerce Act] certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information [information required by clause 5.4.9(2)] for the purpose of the supplier's **CPP proposal**, it was appropriate to make the **arm's-length deductions** the amount and nature of which are detailed in the tables below, **namely**:	N / A			
654		Table 4 of Schedule B / Table 5 of Schedule B / Table 3 of Schedule C / Table 4 of Schedule C [delete as appropriate]."	N / A			
655	5.4.10(2)	Where, in relation to regulated service asset values, OVABAA was applied for the purpose of this clause in accordance with Subpart 3 Section 2, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in respect of its application in the following terms, where words in bold bear the meanings specified in this determination:	Application	Appendix V		OVABAA not used
656		"I, [insert name], **director** of [insert name of Supplier of **services** regulated under Part 4 of the Commerce Act] certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information (being information required by clause 5.4.9(2)) for the purpose of the supplier's **CPP proposal**-	N / A			
657		(a) the attached information is accurate;	N / A			
658		(b) the **OVABAA** was applicable in accordance with clause 2.1.2; and	N / A			
659		(c) the following **unregulated services** would be **unduly deterred** had adjustments to allocations of **regulated service asset values** (in accordance with clause 2.1.4) not been made: [list relevant **unregulated services**]."	N / A			
660	5.4.10(3)	Where, in relation to operating costs provided in a CPP proposal in accordance with subclause 5.4.8(1) and Schedule C, the OVABAA was applied, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in respect of application of the OVABAA in the following terms:	Application	Appendix V		OVABAA not used

661		"I, [insert name], **director** of [insert name of Supplier of **services** regulated under Part 4 of the Commerce Act] certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information (being information required by clause 5.4.9(2)) for the purpose of the supplier's **CPP proposal**-	N / A			
662		(a) the attached information is accurate;	N / A			
663		(b) the **OVABAA** was applicable in accordance with clause 2.1.2; and	N / A			
664		(c) the following **unregulated services** would be **unduly deterred** had adjustments to allocations of **operating costs** (in accordance with clause 2.1.4) not been made: [list relevant **unregulated services**]."	N / A			
665	**SECTION 5 RAB roll forward information**		**N / A**			
666	5.4.11	**RAB roll forward information**	Financial/Model report	Chapter 7		
667		For each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, provide values, in accordance with Subpart 3 Section 2, for the-				
668	5.4.11(a)	total opening RAB value; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$13:$N$13		
669	5.4.11(b)	sum of each of the following things:				
670	5.4.11(b)(i)	forecast value of commissioned assets; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$17:$N$17		
671	5.4.11(b)(ii)	closing RAB values.	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$18:$N$18		
672	5.4.12	**Depreciation information**	Financial/Model report	Chapter 7	Section 7.4	
673	5.4.12(1)	In respect of each disclosure year of the CPP regulatory period, the CPP applicant must provide the information specified in this clause.	Financial/Model report	Chapter 7	Section 7.4	
674	5.4.12(2)	The sum of depreciation				
675	5.4.12(2)(a)	by either asset category or each type of asset for which the proposed method of determining depreciation is the standard depreciation method; and	Financial Model	Included in '[2. Supporting Model - Other vProposal.xlsx]RAB'		Sum of depreciation is calculated using the standard depreciaiton method by asset category
676	5.4.12(2)(b)	for each type of asset where the proposed method of determining depreciation is an alternative depreciation method.	N / A			Not applicable - alternative depreciation not used
677	5.4.12(3)	For each type of asset to which subclause (2)b) applies-	N / A			
678	5.4.12(3)(a)	a description of the type of asset;	N / A			
679	5.4.12(3)(b)	a description of the proposed depreciation method;	N / A			
680	5.4.12(3)(c)	where the proposed asset life is different to the physical asset life, the proposed asset life for the type of asset;	N / A			
681	5.4.12(3)(d)	where the proposed asset life for the type of asset is different to the physical asset life, the proposed remaining asset life;	N / A			
682	5.4.12(3)(e)	forecast depreciation over the asset life for the type of asset, including details of all assumptions made;	N / A			
683	5.4.12(3)(f)	forecast depreciation over the asset life for the type of asset determined in accordance with the standard depreciation method;	N / A			
684	5.4.12(3)(g)	evidence to demonstrate that the proposed depreciation method including, where applicable, any proposed asset life different to the physical asset life, better meets the purpose of Part 4 of the Act than the standard depreciation method; and	N / A			
685	5.4.12(3)(h)	a description of any consultation undertaken with consumers on the proposed depreciation method, including-	N / A			
686	5.4.12(3)(h)(i)	the extent of any consumer disagreement; and	N / A			
687	5.4.12(3)(h)(ii)	the EDB's view in response.	N / A			
688	5.4.12(4)	For each asset or type of asset for which a different physical asset life to the standard physical asset life is proposed-	N / A			Not applicable - Aurora's CPP does not propose a different physical asset life to the standard physical asset life for any assets
689	5.4.12(4)(a)	a description of the assets or types of asset;	N / A			

690	5.4.12(4)(b)	to which clauses 2.2.8(1)(c) and 2.2.8(1)(i)(v) apply, an engineer's report addressing the suitability of the proposed physical asset life; and	N / A			
691	5.4.12(4)(c)	any other evidence to demonstrate that the requirements of clause 2.2.8 in respect of the particular type of asset are met.	N / A			
692	5.4.13	**Revaluation information**	Financial/Model report	Chapter 7	Table 7.13	
693	5.4.13(1)	For each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, provide the following:				
694	5.4.13(1)(a)	sum of opening RAB values;	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx'!$H$13:$N$13		
695	5.4.13(1)(b)	forecast CPI for CPP revaluation for the last quarter of the disclosure year;	Financial Model	[CPI-model-EDB-DPP3-final-determination-27-November-2019.xlsx]Output'!$H$8:$N$8		We have used the values from the Commission's CPI model for the DPP3 Final Determination
696	5.4.13(1)(c)	forecast CPI for CPP revaluation for the last quarter of the preceding disclosure year; and	Financial Model	[CPI-model-EDB-DPP3-final-determination-27-November-2019.xlsx]Output'!$H$8:$N$8		We have used the values from the Commission's CPI model for the DPP3 Final Determination
697	5.4.13(1)(d)	revaluation rate.	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$71:$N$71		
698	5.4.14	**Commissioned assets information**	Financial/Model report	Chapter 7	Section 7.3	
699	5.4.14(1)	For each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, provide the-	Financial/Model report	Chapter 7	Section 7.3	
700	5.4.14(1)(a)	sum of value of commissioned assets; and	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$67		
701	5.4.14(1)(b)	sum of forecast value of commissioned assets,	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$I$67:$N$67		
702		in respect of each of the following groups of assets:	Financial/Model report	Chapter 7	Section 7.3	
703	5.4.14(1)(c)	assets-	Financial/Model report	Chapter 7	Section 7.3	
704	5.4.14(1)(c)(i)	acquired or intended to be acquired from a related party; or	Financial/Model report Application	Chapters 6, 7 Appendix O	Sections 6.4, 7.3.1, 7.7	
705	5.4.14(1)(c)(ii)	transferred from a part of the EDB that supplies unregulated services;	Financial/Model report	Chapter 7	Section 7.3.1	
706	5.4.14(1)(d)	assets-	Financial/Model report	Chapters 6, 7	Section 7.3.1 and 6.4	
707	5.4.14(1)(d)(i)	acquired or intended to be acquired from another regulated supplier and used by that regulated supplier in the supply of regulated services; or	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - our expenditure forecasts do not include any forecast acquisitions from other regulated entities that have been used by that regulated supplier in the supply of regulated goods or services
708	5.4.14(1)(d)(ii)	transferred or intended to be transferred from a part of the EDB that supplies other regulated services;	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - we do not provide any other regulated services
709	5.4.14(1)(e)	network spares; and	Financial/Model report	Chapter 7	Section 7.3.1	Not applicable - our forecast value of commissioned assets does not include any network spares
710	5.4.14(1)(f)	all other assets having a commissioning date or forecast to have a commissioning date in that period.	Financial/Model report Application	Chapter 7 Appendix O	Section 7.3.1	
711	5.4.14(2)	In respect of each value provided in accordance with subclause (1) provide-				
712	5.4.14(2)(a)	all data, information, calculations and assumptions used to derive it from relevant data provided in the capex forecast; and	Financial/Model report	Chapter 7	Section 7.3.7	

713	5.4.14(2)(b)	where capital contributions are taken into account in any value disclosed pursuant to subclause (1)-	Application 2020 AMP	Appendix G Chapters 5, 6 and Appendix B	Sections 5.3.1 and 6.8.2	Capital contributions are separately identified for consumer connections and asset relocations in AMP schedules 11a(ii) and 11a(v), set out in Appendix B to the AMP.
714	5.4.14(2)(b)(i)	the amount of such capital contributions, with respect to asset types and quantities; and	Application 2020 AMP	Appendix G Chapters 5, 6 and Appendix B	Sections 5.3.1 and 6.8.2	Capital contributions are separately identified for consumer connections and asset relocations in AMP schedules 11a(ii) and 11a(v), set out in Appendix B to the AMP.
715	5.4.14(2)(b)(ii)	policies relevant to such capital contributions.	SharePoint data room	IPL758 AE-S010-Capital Contributions-v1.3		Refer to Aurora's capital contributions policy
716	5.4.14(3)	In respect of each asset to which subclause (1)(c) applies, provide—	Financial/Model report	Chapter 7, Appendix B	Section 7.7	
717	5.4.14(3)(a)	the name of the relevant person or other part of the EDB, as the case may be; and	Financial/Model report	Chapter 7, Appendix B	Section 7.7	
718	5.4.14(3)(b)	where the acquisition was or is intended to be from a related party, a description of the relationship between the EDB and that person.	Financial/Model report	Chapter 7, Appendix B	Section 7.7	
719	5.4.14(4)	In respect of the likely vendor of each asset to which subclause (1)(d) applies, provide—	N / A			Not applicable as subclause 1(d) does not apply: We do not provide any other regulated services and our expenditure forecasts do not include any forecast acquisitions from other regulated entities that have been used by that regulated supplier in the supply of regulated goods or services
720	5.4.14(4)(a)	the name of the vendor;	N / A			
721	5.4.14(4)(b)	a description of each asset likely to be acquired from that vendor; and	N / A			
722	5.4.14(4)(c)	the forecast closing RAB value of each asset in the vendor's regulatory asset base for the disclosure year in which the acquisition is intended.	N / A			
723	5.4.15	**Asset disposals information**	Financial/Model report	Chapter 6	Section 7.6	
724	5.4.15(1)	For each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, in respect of each of the following groups of assets:	Financial/Model report	Chapter 6	Section 7.6	
725	5.4.15(1)(a)	assets likely to be-	Financial/Model report	Chapter 6	Section 7.6	
726	5.4.15(1)(a)(i)	sold to a related party; or	Financial/Model report	Chapter 6	Section 7.6	Not applicable - no assets are forecast to be sold to a related party or transferred to another part of the EDB.
727	5.4.15(1)(a)(ii)	transferred to another part of the EDB; and	Financial/Model report	Chapter 6	Section 7.6	Not applicable - no assets are forecast to be sold to a related party or transferred to another part of the EDB.
728	5.4.15(1)(b)	all other disposed assets,	Financial/Model report	Chapter 6	Section 7.6	
729		provide the-				
730	5.4.15(1)(c)	sum of unallocated opening RAB values; and	Financial Model	Included in '[2. Supporting Model - Other vProposal.xlsx]Assets		
731	5.4.15(1)(d)	sum of opening RAB values.	Financial Model	Included in '[2. Supporting Model - Other vProposal.xlsx]Assets		
732	5.4.15(2)	In respect of each asset to which the values provided pursuant to subclause (1) relate, provide—	N / A			Not applicable - no assets are forecast to be sold to a related party or transferred to another part of the EDB.
733	5.4.15(2)(a)	the name of the relevant person or other part of the EDB, as the case may be; and	N / A			
734	5.4.15(2)(b)	where the disposal is proposed to be to a related party, a description of the relationship between the EDB and that person.	N / A			
735	5.4.16	**Works under construction information**	Financial/Model report	Chapter 7	Section 7.3.7	
736		For each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, provide-				

737	5.4.16(a)	opening works under construction;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$15:$S$15		The works under construction roll forward excludes right-of-use assets. ROU assets are included in capital expenditure and commissioned assets in the same year.
738	5.4.16(b)	sum of capital expenditure;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$16:$S$16		
739	5.4.16(c)	sum of value of commissioned assets but only to the extent that values are included in closing RAB values disclosed pursuant to an ID determination;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$17:$M$17		
740	5.4.16(d)	sum of forecast value of commissioned assets but only to the extent that values are included in the sum of closing RAB values provided pursuant to clause 5.4.11(b)(ii); and	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$N$17:$S$17		
741	5.4.16(e)	sum of closing works under construction.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Works under construction'!$L$18:$S$18		
742	**SECTION 6 Tax information**					
743	5.4.17	**Interpretation**				
744		In this section, a term that is not emboldened but is defined for the purpose of a specific clause in Subpart 3 Section 3 bears the same meaning as it does in the clause of Subpart 3 Section 3 in which it is defined.				
745	5.4.18	**Period in respect of which tax information to be provided**	Financial/Model report	Chapter 8		
746		A CPP proposal must contain the information specified in this section for each disclosure year, after the last disclosure made under an ID determination, until the last disclosure year of the next period, in accordance with Subpart 3 Section 3.	Financial/Model report	Chapter 8		
747	5.4.19	**Regulatory tax allowance information**	Financial/Model report	Chapter 8		
748	5.4.19(1)	forecast regulatory tax allowance and particulars of how it was calculated	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$17:$N$17		
749	5.4.19(2)	other regulated income	Financial/Model report Application	Chapter 8 Chapter 3, Appendix S	Section 8.1 Section 3.5	The Commission has approved an exemption from the requirement to provide information regarding other regulated income
750	5.4.19(3)	sum of discretionary discounts and customer rebates;	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$50:$S$50		Not applicable - Aurora does not have any discretionary discounts or customer rebates, and is not forecasting to have any during the CPP period In addition, refer to Section 8.2 in Chapter 8 of the Financial/Model report
751	5.4.19(4)	notional deductible interest and the cost of debt assumptions relied upon in its calculation	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx'!$H$65:$N$65		In addition, refer to Section 8.3.3 in Chapter 8 of the Financial/Model report
752	5.4.20	**Tax losses information**	Financial/Model report	Chapter 8	Section 8.4	Not applicable - there are no opening or current period tax losses and we have not forecast any tax loses during the forecast period
753	5.4.20(1)	amount of opening tax losses (if any) and particulars of how it was calculated	N / A	N / A	N / A	

754	5.4.20(2)	information describing the nature and amounts of significant items giving rise to any opening tax losses	N / A	N / A	N / A	
755	5.4.20(3)	information demonstrating that any opening tax losses arose from the supply of electricity distribution services	N / A	N / A	N / A	
756	5.4.21	**Permanent differences information**	Financial/Model report	Chapter 8	Section 8.2	
757	5.4.21(1)	sum of positive permanent differences	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$13:$S$13		
758	5.4.21(2)	sum of negative permanent differences	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Regulatory tax '!$M$14:$S$14		
759	5.4.21(3)	amounts and nature of items used to determine-	Financial/Model report	Chapter 8	Section 8.2	
760	5.4.21(3)(a)	positive permanent differences; and	Financial/Model report	Chapter 8	Section 8.2	
761	5.4.21(3)(b)	negative permanent differences	Financial/Model report	Chapter 8	Section 8.2	
762	5.4.22	**Amortisation of initial differences in asset values information**	Financial/Model report	Chapter 8	Section 8.3.1	
763	5.4.22(1)	opening unamortised balance of the initial differences in asset values by asset category	Financial/Model report Application	Chapter 8 Chapter 3, Appendix S	Section 8.3.1 Section 3.5	A modification has been approved to allow Aurora to provide the opening unamortised balance of the initial differences in asset values at an aggregated level.
764	5.4.22(2)	amortisation in respect of the disclosure year	Financial Model	[1. CPP Financial Model vProposal.xlsm]TAXx '!$H$49:$N$49		
765	5.4.22(3)	average weighted remaining useful life of the assets relevant to calculation of the initial regulatory tax asset value	Financial Model	[1. CPP Financial Model vProposal.xlsm]General'!$H$47:$N$47		
766	5.4.23	**Amortisation of revaluations information**	Financial/Model report	Chapter 8	Section 8.3.2	
767	5.4.23(1)	unamortised balance of revaluations to date	Financial/Model report Application	Chapter 8 Chapter 3, Appendix S	Section 8.3.2 Section 3.5	An exemption has been approved from the requirements in sub-clauses (1), (3), and (4).
768	5.4.23(2)	adjusted depreciation	Financial Model	[1. CPP Financial Model vProposal.xlsm]RABx '!$H$66:$N$66		
769	5.4.23(3)	average weighted remaining useful life of the assets used to determine the amortisation of revaluations	Financial/Model report Application	Chapter 8 Chapter 3, Appendix S	Section 8.3.2 Section 3.5	An exemption has been approved from the requirements in sub-clauses (1), (3), and (4).
770	5.4.23(4)	particulars of how the average weighted remaining useful life was calculated	Financial/Model report Application	Chapter 8 Chapter 3, Appendix S	Section 8.3.2 Section 3.5	An exemption has been approved from the requirements in sub-clauses (1), (3), and (4).
771	5.4.24	**Deferred tax information**	Financial/Model report	Chapter 8	Section 8.6	
772	5.4.24(1)	opening deferred tax	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$14:$N$14		
773	5.4.24(2)	analysis of temporary differences and other adjustments by nature that give rise to opening deferred tax value	Financial/Model report	Chapter 8	Section 8.6	
774	5.4.24(3)	closing deferred tax	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$30:$N$30		
775	5.4.24(4)	reconciliation of opening deferred tax to closing deferred tax by nature of temporary differences and other adjustments	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'		

776	5.4.25	**Temporary differences information**	Financial/Model report	Chapter 8	Section 8.6.2	
777	5.4.25(1)	description of the methodology and depreciation rates by asset category used to determine the forecast tax depreciation	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Assets'!$D$336:$D$404		
778	5.4.25(2)	amounts and nature of other forecast temporary differences	Financial/Model report	Chapter 8	Section 8.6.2	
779	5.4.25(3)	particulars of the calculation of the tax effect of temporary differences showing tax rates used	Financial Model	[1. CPP Financial Model vProposal.xlsm]DTAX x'!$H$26:$N$26		
780	5.4.26	**Regulatory tax asset value information**	Financial/Model report	Chapter 8	Section 8.6.3	
781	5.4.26(1)	sum of tax asset values at the start of the disclosure year	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$37:$S$37		
782	5.4.26(2)	sum of regulatory tax asset values at the start of the disclosure year	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$26:$S$26		
783	5.4.26(3)	weighted average remaining tax life of assets employed	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$D$431:$D$499		The Commission has granted a modification to the requirement to provide information supporting the tax asset value to enable the specification of diminishing value rates, rather than useful lives, where appropriate. For further detail on this modification, refer to Section 3.5 of Chapter 3 and Appendix S of the Application. Note that regulatory tax asset values have been calculated in accordance with the modification to this clause.
784	5.4.26(4)	tax depreciation methodology employed	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$431:$S$499		
785	5.4.26(5)	particulars of the calculation used to derive the regulatory tax asset values at the start of the disclosure year from the tax asset values at the start of the disclosure year	N / A			Not applicable - regulatory tax asset values have been calculated in accordance with the modification to 5.4.26(3)
786	5.4.26(6)	sum of regulatory tax asset values at the end of the disclosure year	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$30:$S$30		
787	5.4.26(7)	reconciliation between the sum of regulatory tax asset values at the start of the disclosure year in accordance with subclause (2) and the sum of regulatory tax asset values at the end of the disclosure year in accordance with subclause (6) showing the values of capital additions, disposals, tax depreciation and other asset adjustments including cost allocation adjustments.	Financial Model	[2. Supporting Model - Other vProposal.xlsx]RTAV'!$M$27:$S$30		In addition, refer to Section 8.6.3 of Chapter 8 of the Financial/Model report
788	**SECTION 7 Cost of capital information**					
789	5.4.27	**Information regarding WACC and TCSD allowance**	Financial/Model report	Chapter 5	Section 5.3	
790	5.4.27(1)	A CPP proposal must, subject to subclause (2), identify the 67th percentile estimate of WACC used for the purpose of clause 5.4.7(1).	Financial Model	[2. Supporting Model - Other vProposal.xlsx]Cost of capital '!$N$40:$S$40		
791	5.4.27(2)	For the purpose of subclause (1), the identified 67th percentile estimate of WACC is the applicable cost of capital specified in clause 5.3.22.	Financial/Model report	Chapter 5	Section 5.3	
792	5.4.27(3)	Where a term credit spread differential allowance is proposed, a CPP proposal must contain all data, information, calculations, and assumptions used to determine any proposed term credit spread differential.	N / A	N / A	N / A	Not applicable - no term credit spread differential is applied
793	**Section 8 Expenditure information**					
794	5.4.28	**Capex, opex, demand and network qualitative information**				
795		The information specified in Schedule D must be-				
796	5.4.28(a)	contained in a CPP proposal; and	Application	Chapter 4, Appendix U	Section 4.5	
797	5.4.28(b)	provided in accordance with the requirements of that schedule.	Application	Chapter 4, Appendix U	Section 4.5	

798	5.4.29	**Capex, opex, demand and network quantitative information**	Application	Chapter 4, Appendix H	Section 4.6	
799	5.4.29(1)	A CPP proposal must contain the information specified in the regulatory templates and that information must be-				
800	5.4.29(1)(a)	in spreadsheet format whereby each item of data is linked between all cells to which it is relevant, irrespective of whether such cells are on the same or different tabs; and	Financial Model			This requirement is met using the Financial Model
801	5.4.29(1)(b)	provided in accordance with the instructions specified in clause 5.4.30.	Financial Model			This requirement is met using the Financial Model
802	5.4.29(2)	'Regulatory templates' means the tables included in Schedule E named-				
803	5.4.29(2)(a)	Table 1: Projects and programmes;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 1		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
804	5.4.29(2)(b)	Table 2: Capex summary;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 2		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
805	5.4.29(2)(c)	Table 3: Opex summary;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 3		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
806	5.4.29(2)(d)	Table 4: Capex projects and programmes;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 4		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
807	5.4.29(2)(e)	Table 5: Capex by asset categories;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 5		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
808	5.4.29(2)(f)	Table 6: Opex projects and programmes;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 6		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
809	5.4.29(2)(g)	Table 7: Non-network opex;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 7		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
810	5.4.29(2)(h)	Table 8: Aggregate forecast commissioned assets by asset categories;	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 8		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
811	5.4.29(2)(i)	Table 9: Cost escalation factors; and	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 9		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
812	5.4.29(2)(j)	Table 10: Network demand forecasts.	SharePoint data room	S-10 Schedule E Table 10.xlsx		In addition, refer to Appendix O and Section 4.6 of Chapter 4 of the Application
813	5.4.29(3)	Where data provided in accordance with subclause (1) has been computed or derived from other amounts or values on the spreadsheet through the use of formulae, the underlying formulae for the cells containing the data must be accessible.	Financial Model			The underlying formulae for the cells containig the data are accessible
814	5.4.29(4)	For the purpose of subclause (1), terms used in the regulatory templates must be interpreted in the same way as those terms are defined for the purpose of Schedule D.				
815	5.4.30	**Instructions for completion of the regulatory templates**				
816	5.4.30(1)	Provide the information specified in Table 1: Projects and programmes of the regulatory templates for all projects or programmes that form part of the CPP proposal.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 1		In addition, refer to Appendix O of the Application
817	5.4.30(2)	Provide the information specified in Table 2: Capex summary of the regulatory templates using the information provided in Table 4: Capex projects and programmes of the regulatory templates, where-	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 2		In addition, refer to Appendix O of the Application
818	5.4.30(2)(a)	the values in Table 2: Capex summary must reconcile with the total values in Table 4: Capex projects and programmes and Table 8: Aggregate forecast commissioned assets by asset categories of the regulatory templates; and	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 2		In addition, refer to Appendix O of the Application

819	5.4.30(2)(b)	the total forecast value of capex resulting in commissioned assets in Table 2c of Schedule E must reconcile with the total value of commissioned assets in Table 2d of Schedule E.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 2		In addition, refer to Appendix O of the Application
820	5.4.30(3)	Provide the information in Table 3: Opex summary of the regulatory templates using the information provided in Table 6: Opex projects and programmes of the regulatory templates.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 3		In addition, refer to Appendix O of the Application
821	5.4.30(4)	Provide the information specified in Table 4: Capex projects and programmes and Table 6: Opex projects and programmes of the regulatory templates for each project and for each programme.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 4','[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 6		In addition, refer to Appendix O of the Application
822	5.4.30(5)	Provide the information specified in Table 5: Capex by asset categories of the regulatory templates.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 5		In addition, refer to Appendix O of the Application
823	5.4.30(6)	Provide the information specified in Table 7: Non-network opex of the regulatory templates in respect of system operation and network support opex and business support opex.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 7		In addition, refer to Appendix O of the Application
824	5.4.30(7)	Provide the information specified in Table 8: Aggregate forecast commissioned assets by asset categories of the regulatory templates.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 8		In addition, refer to Appendix O of the Application
825	5.4.30(8)	Provide the information specified in Table 9: Cost escalation factors of the regulatory templates for each of the cost escalators used to convert real prices to nominal prices.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 9		In addition, refer to Appendix O of the Application
826	5.4.30(9)	Provide the information specified in Table 10: Network demand forecasts of the regulatory templates.	SharePoint data room	S-10 Schedule E Table 10.xlsx		In addition, refer to Appendix O of the Application
827	5.4.30(10)	For the purpose of specifying the relevant capex category or opex category in accordance with subclause (4), where expenditure within each project or programme is relevant to more than one capex category or opex category-	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 4		In addition, refer to Appendix O of the Application
828	5.4.30(10)(a)	select the capex category or opex category that is most relevant based on the nature of the expenditure; or	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]		In addition, refer to Appendix O of the Application
829	5.4.30(10)(b)	redefine the project or programme into two or more new projects or programmes and reallocate the expenditure so as to resolve the overlap.	Financial Model	[3. Supporting Model - Expenditure vProposal.xlsx]Sch E table 4		In addition, refer to Appendix O of the Application
830	**SECTION 9 Information relevant to prices**		**N / A**			
831	5.4.31	**Information on proposed new pass-through costs**	Financial/Model report	Chapter 11	Section 11.2.1	Not applicable - No new pass-through costs are proposed that haven't already been included in the Commission's DPP decision
832		A CPP proposal must contain details of any cost not specified in clause 3.1.2(2) that is sought to be specified as a new pass-through cost in accordance with clause 3.1.2(1)(b), including information on-	N / A	N / A	N / A	
833	5.4.31(a)	how the cost is likely to arise;	N / A	N / A	N / A	
834	5.4.31(b)	who the cost would be payable to;	N / A	N / A	N / A	
835	5.4.31(c)	how the cost would be calculated;	N / A	N / A	N / A	
836	5.4.31(d)	any good or service the EDB would receive in exchange; and	N / A	N / A	N / A	
837	5.4.31(e)	how the cost meets the criteria specified in clause 3.1.2(3).	N / A	N / A	N / A	
838	5.4.32	**Information on proposed recoverable costs relating to costs of making CPP application**				
839		Where a CPP applicant seeks specification in the CPP determination of a recoverable cost to which clause 3.1.3(1)(j), 3.1.3(1)(k), or 3.1.3(1)(l) applies, it must provide, in relation to each auditor, verifier or engineer who was engaged to provide an opinion on some aspect of the CPP proposal in accordance with a requirement of this Part-				

840	5.4.32(a)	any document making a public or limited circulation request for proposals to carry out the work;	Financial/Model report Application SharePoint dataroom	Chapter 11, Appendix C Chapter 3 S-02 - 20171221 Verifier RFP Final S-03 - 20190205 Verifier - Updated RFP	Section 11.2.2 Sections 3.2 & 3.3	Note that as Audit NZ is our required auditor, no tender process was used in relation to the auditor
841	5.4.32(b)	the terms of reference for the work;	Financial/Model report Application SharePoint dataroom	Chapter 11, Appendix C Chapter 3 S-04 - 20190617 Verifier Terms of Engagement (Executed) S-05 - 20191001 Aurora CPP Engagement Letter [Signed Copy] S	Section 11.2.2 Sections 3.2 & 3.3	
842	5.4.32(c)	invoices for services undertaken in respect of the work; and	Financial/Model report Application SharePoint dataroom	Chapter 11, Appendix C Chapter 3 S-06 - Audit NZ invoices S-08 - Farrierswier invoices	Section 11.2.2 Sections 3.2 & 3.3	
843	5.4.32(d)	receipts for payment by the CPP applicant.	Financial/Model report Application SharePoint dataroom	Chapter 11, Appendix C Chapter 3 S-07 - Audit NZ payments S-09 - Farrierswier payments	Section 11.2.2 Sections 3.2 & 3.3	
844	**SECTION 10 Information relevant to alternative methodologies**					
845	5.4.33	**Demonstration that alternative methodologies have equivalent effect**	Application	Appendix V		Not applicable - We do not propose any AMWEEs in our CPP proposal
846	5.4.33(1)	Where a CPP applicant applies alternative methodologies in accordance with clause 5.3.26, it must provide:	N / A			
847	5.4.33(1)(a)	a list and description of each alternative methodology applied;	N / A			
848	5.4.33(1)(b)	an indication, at the relevant locations within the CPP application, as to where the alternative methodologies have been applied;	N / A			
849	5.4.33(1)(c)	reasons why each of the alternative methodologies have been applied; and	N / A			

850	5.4.32(a)	any document making a public or limited circulation request for proposals to carry out the work;	Financial/Model report Application SharePoint dataroom	Chapter 11, Appendix C Chapter 3 S-02 - 20171221 Verifier RFP Final S-03 - 20190205 Verifier - Updated RFP	Section 11.2.2 Sections 3.2 & 3.3	Note that as Audit NZ is our required auditor, no tender process was used in relation to the auditor
851	5.4.33(2)	Paragraph (1)(d) may be satisfied by submitting a certificate signed by an senior manager of the CPP applicant setting out the factual basis on which he or she believes each alternative methodology complies with clause 5.3.26(3).	N / A			
852	**SUBPART 5 Consumer consultation, verification, audit and certification**					
853	5.5.1	**<u>Consumer consultation</u>**				Refer to Section 2.7 of the Consultation Report which sets out how Aurora fulfilled the regulatory requirements for consultation.
854	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-	Consultation Report Application	Chapters 3 & 4 Appendix C	Section 3.4	In May 2017, we signalled our intention to apply for a CPP and communicated that to 80,000 households throughout our network region via newsletter drop. Our engagement process comprised five phases. A summary of these phases is set out in section 2.4, with more detailed information at Chapter 4.
855	5.5.1(1)(a)	that it intends to make a CPP proposal;	Consultation Report *Your Network, Your Say* Consultation Document	Chapters 3 & 4, Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document.	Page 7 of Consultation Document	
856	5.5.1(1)(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;	Consultation Report *Your Network, Your Say* Consultation Document 22 October 2019 Customer Advisory Panel Stakeholder briefings	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document. Minutes and slide deck of 22 October 2019 Customer Advisory Panel are available on SharePoint at IP1260 and IP1280. Slide deck for stakeholder briefings are available on SharePoint at IP1254 to IP1255 and IP1262 to IP1265.	Pages 24 - 27 of Consultation Document	

857	5.5.1(1)(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;	Consultation Report *Your Network, Your Say* Consultation Document	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document.	Pages 44 - 47 of Consultation Document	
858	5.5.1(1)(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;	Consultation Report Your Network, Your Say Consultation Document 25 November 2019 Customer Advisory Panel 26, 27 and 28 November 2019 Customer Voice Panels Stakeholder briefings	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document. The slide deck of 25 November 2019 Customer Advisory Panel are available on SharePoint at IP1125 (refer pages 32 - 34). Slide deck for stakeholder briefings are available on SharePoint at IP1254 to IP1255 and IP1262 to IP1265.	Pages 24 - 25, 44 - 47 of Consultation Document	
859	5.5.1(1)(e)	where and how further information in respect of the intended CPP proposal may be obtained;	Consultation Report *Your Network, Your Say* Consultation Document	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document.	Pages 2, 48, 51 of Consultation Document	Also refer to https://yoursay.auroraenergy.co.nz/
860	5.5.1(1)(f)	of the process for making submissions to the EDB in respect of the intended CPP proposal; and	Consultation Report *Your Network, Your Say* Consultation Document	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document.	Pages 2, 7, 49 - 51 of Consultation Document	Also refer to https://yoursay.auroraenergy.co.nz/

861	5.5.1(1)(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.	Consultation Report *Your Network, Your Say* Consultation Document *Your Network, Your Say* Consultation Summary Stakeholder and media updates on 17, 24 and 27 January and 6 March 2020	Appendix G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document. Consultation Summary found at Aurora's website. The stakeholder and media updates are found at pages 206 - 214 of the "Consultation Report Appendices" document.	Pages 12, 15 of Consultation Document Page 1 of Consultation Summary	Also refer to https://yoursay.auroraenergy.co.nz/
862	5.5.1(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.	N / A			Not applicable. As set out at section 2.5 of the Consultation Report, we used a range of engagement channels to communicate with customers, including Customer Voice Panels, Customer Advisory Panel, stakeholder briefings, the *Your Network, Your Say* website, published consultation document and drop-in sessions. Regardless, hard copies of the consultation document were also readily available at 12 locations and mailed on request.
863	5.5.1(3)	For the purpose of subclause (1), the CPP applicant must-	Consultation Report *Your Network, Your Say* Consultation Document *Your Network, Your Say* Consultation Summary Customer voice panels Customer advisory panel Stakeholder briefings Drop-in sessions Media communications	Chapters 3 - 4 & Appendices F - G Consultation Document found at pages 150 - 214 of "Consultation Report Appendices" document. Consultation Summary found at Aurora's website here. Summaries, minutes and slide decks for customer voice panels, customer advisory panel, stakeholder briefings, drop-in sessions and media communications are available on the SharePoint data room from IP1254 to IP1325.		Also refer to https://yoursay.auroraenergy.co.nz/

864	5.5.1(3)(a)	provide all relevant information;	Consultation Report Application Appendix 3	Chapters 3 - 4 & Appendices F - G		Refer to documents referenced under clause 5.5.1(3)
865	5.5.1(3)(b)	provide information in a manner that promotes consumer engagement;	Consultation Report	Chapters 3 - 4 & Appendices F - G		Refer to documents referenced under clause 5.5.1(3)
866	5.5.1(3)(c)	make best endeavours to express information clearly, including by use of plain language and the avoidance of jargon; and	Consultation Report	Chapters 3 - 4 & Appendices F - G		Refer to documents referenced under clause 5.5.1(3)
867	5.5.1(3)(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.	Consultation Report Direct email to stakeholders Customer voice panels Customer advisory panel Stakeholder briefings Drop-in sessions Media communications Print and digital advertising	Appendix G The stakeholder and media updates are found at pages 206 - 214 of the "Consultation Report Appendices" document. Summaries, minutes and slide decks for customer voice panels, customer advisory panel, stakeholder briefings, drop-in sessions and media communications are available on the SharePoint data room from IP1254 to IP1325.		As set out at section 2.5 of the Consultation Report, we used a range of engagement channels to communicate with customers, including Customer Voice Panels, Customer Advisory Panel, stakeholder briefings, the Your Network, Your Say website, published consultation document and drop-in sessions. Also refer to https://yoursay.auroraenergy.co.nz/
868		Examples:				Refer to comment above in relation to clause 5.5.1(3)(d)
869	5.5.1(3)(d)(i)	*by placing the information on the EDB's website;*				Refer to comment above in relation to clause 5.5.1(3)(d)
870	5.5.1(3)(d)(ii)	*by providing the information to groups or organisations that represent the consumers' relevant interests;*				Refer to comment above in relation to clause 5.5.1(3)(d)
871	5.5.1(3)(d)(iii)	*by including the information in consumers' or electricity retailers' bills; and/or*				Refer to comment above in relation to clause 5.5.1(3)(d)
872	5.5.1(3)(d)(iv)	*by placing advertisements in local newspapers.*				Refer to comment above in relation to clause 5.5.1(3)(d)

873	5.5.2	**Verification**				
874	5.5.2(1)	A CPP proposal must be verified by a verifier.	IV Report	Appendix H		
875	5.5.2(2)	The verifier must be engaged in accordance with Schedule F.	Application SharePoint data room	Appendix C S-04- 20190617 Verifier Terms of Engagement (Executed)	Section C.2	Parties: Aurora Energy Limited / Farrier Swier Consulting Pty Ltd. Executed on 11 June 2019 Refer to the Terms of Engagement with the Verifier
876	5.5.2(3)	The CPP applicant must provide the verifier with-	IV Report Application	Appendix I, Chapter 2 Chapter 3, Appendix C	Section 2.3 Sections 3.2, C.2.2	This requirement was met through data and documents uploaded to a SharePoint site. Appendix I of the IV Report lists all of the information provided. Chapter 2.3 describes the process of document and information submission to the Verifier.
877	5.5.2(3)(a)	the materials-	IV Report	Appendix I, Chapter 2	Section 2.3	
878	5.5.2(3)(a)(i)	required by the verifier to verify the CPP proposal in accordance with the terms of his, her or its engagement and Schedule G; and	IV Report	Appendix I, Chapter 2	Section 2.3	This requirement was met through data and documents uploaded to a SharePoint site. Appendix I of the IV Report lists all of the information provided. Chapter 2.3 describes the process of document and information submission to the Verifier.
879	5.5.2(3)(a)(ii)	that it intends to submit to the Commission as a CPP proposal;	IV Report	Appendix I, Chapter 2	Section 2.3	
880	5.5.2(3)(b)	subject to paragraph (c), the materials referred to in paragraph (a) prior to the verifier commencing verification in accordance with Schedule G;	IV Report	Appendix I, Chapter 2	Section 2.3	
881	5.5.2(3)(c)	upon the verifier’s request, the information described in clause D10 pertaining to identified programmes after the verifier has notified the CPP applicant of its selection of identified programmes;	IV Report	Appendices C & I, Chapter 2	Section 2.3	Appendix C of the IV Report lists the selected projects, including the relevant documents for each selected project.
882	5.5.2(3)(d)	any information requested by the verifier pursuant to the verifier's right to ask for such information pursuant to his, her or its deed of engagement, as specified in clause F6(2)(d); and	IV Report	Appendix I, Chapter 2	Section 2.3	This requirement was met through data and documents uploaded to a SharePoint site. Appendix I of the IV Report lists all of the information provided. In particular, Table I.2 sets out Aurora's responses to questions provided via the SharePoint dataroom that the Verifier has relied upon when developing its report and Table I.3 sets out Aurora's responses to the Verifier's draft report provided via the SharePoint dataroom which the Verifier has considered in completing the final report.
883	5.5.2(3)(e)	in advance of the verifier’s selection of identified programmes, summary information on the forecast projects and programmes, in the format specified in Table 1: Projects and programmes of the regulatory templates.	SharePoint data room	IPC-1120 Identified Programme Analysis for IV .xlsx		Note that the Verifier requested additional information about our forecast projects and programmes beyond the information set out in Table 1 of the Schedule E regulatory templates, such as percentage uplifts and references to the overall CPP justification. Accordingly, we provided information on the forecast projects and programmes in spreadsheet format rather than using the format specified in Table 1 of the Schedule E regulatory templates. However, the information we provided to the Verifier included all the information required by the Schedule E templates.

884	5.5.3	**Audit and assurance**				
885	5.5.3(1)	A CPP application must include a report by an auditor that states whether or not:	Application	Chapter 3, Appendix Q	Section 3.3	
886	5.5.3(1)(a)	as far as appears from an examination of them, proper records to enable the compilation of information required by Subpart 4 have been kept by the CPP applicant;	Application	Chapter 3, Appendix Q	Section 3.3	
887	5.5.3(1)(b)	in the case of actual financial information relating to the current period, that information has been prepared in all material respects in accordance with the input methodologies set out in this determination, and that it has been audited in accordance with applicable auditing standards issued by the External Reporting Board in accordance with its functions under the Financial Reporting Act 2013 or any equivalent standards that replace these standards;	Application	Chapter 3, Appendix Q	Section 3.3	
888	5.5.3(1)(c)	in the case of forecast financial information relating to the next period, that information has been compiled in all material respects in accordance with the input methodologies set out in this determination, and that it has been examined in accordance with applicable assurance engagement standards issued by the External Reporting Board in accordance with its functions under the Financial Reporting Act 2013 or any equivalent standards that replace these standards or other appropriate standards;	Application	Chapter 3, Appendix Q	Section 3.3	
889	5.5.3(1)(d)	in the case of quantitative historical information provided in spreadsheets, the information is properly compiled on the basis of the relevant underlying source information; and	Application	Chapter 3, Appendix Q	Section 3.3	
890	5.5.3(1)(e)	in the case of quantitative forecast information provided in spreadsheets, the information is properly compiled on the basis of relevant and reasonable disclosed assumptions.	Application	Chapter 3, Appendix Q	Section 3.3	
891	5.5.3(2)	For the avoidance of doubt, the auditor must provide an opinion as to whether-	Application	Chapter 3, Appendix Q	Section 3.3	
892	5.5.3(2)(a)	in respect of operating costs not directly attributable, the opex forecast was provided by the CPP applicant as specified in clause 5.3.5; and	Application	Chapter 3, Appendix Q	Section 3.3	
893	5.5.3(2)(b)	in respect of regulated service asset values not directly attributable, the forecast value of commissioned assets were provided by the CPP applicant in accordance with clause 5.3.6(3)(b) and as specified in clause 5.3.11(2)(b).	Application	Chapter 3, Appendix Q	Section 3.3	
894	5.5.4	**Certification**				
895	5.5.4(1)	In the case of all information of a quantitative nature, other than forecast information, provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-	Application	Chapter 3, Appendix A	Section 3.4	
896	5.5.4(1)(a)	the information was derived and is provided in accordance with the relevant requirements; and	Application	Chapter 3, Appendix A	Section 3.4	
897	5.5.4(1)(b)	it properly represents the results of financial or non-financial operations as the case may be.	Application	Chapter 3, Appendix A	Section 3.4	

898	5.5.4(2)	In the case of all information of a qualitative nature, other than forecast information, provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-	Application	Chapter 3, Appendix A	Section 3.4	
899	5.5.4(2)(a)	the information is provided in accordance with the relevant requirements; and	Application	Chapter 3, Appendix A	Section 3.4	
900	5.5.4(2)(b)	it properly represents the events that occurred during the current period.	Application	Chapter 3, Appendix A	Section 3.4	
901	5.5.4(3)	In the case of all forecast information provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-	Application	Chapter 3, Appendix A	Section 3.4	
902	5.5.4(3)(a)	the information was derived and is provided in accordance with the relevant requirements; and	Application	Chapter 3, Appendix A	Section 3.4	
903	5.5.4(3)(b)	the assumptions made are reasonable.	Application	Chapter 3, Appendix A	Section 3.4	
904	5.5.4(4)	No fewer than 2 directors of the CPP applicant must certify in writing-	Application	Chapter 3, Appendix A	Section 3.4	
905	5.5.4(4)(a)	that, to the best of his or her knowledge, the verifier was engaged by the CPP applicant in accordance with Schedule F;	Application	Chapter 3, Appendix A	Section 3.4	
906	5.5.4(4)(b)	that, to the best of his or her knowledge, the CPP applicant provided the verifier with all the information specified in Part 5, including its schedules, relevant to Schedule F;	Application	Chapter 3, Appendix A	Section 3.4	
907	5.5.4(4)(c)	that, to the best of his or her knowledge, the information described in clause 5.5.2(3)(e) was provided to the verifier in advance of the verifier's selection of identified programmes;	Application	Chapter 3, Appendix A	Section 3.4	
908	5.5.4(4)(d)	a description of any information not provided to the verifier following the verifier's request;	Application	Chapter 3, Appendix A	Section 3.4	
909	5.5.4(4)(e)	reasons, which, in his or her opinion, justified any non-provision of such information;	Application	Chapter 3, Appendix A	Section 3.4	
910	5.5.4(4)(f)	that, to the best of his or her knowledge, the-	Application	Chapter 3, Appendix A	Section 3.4	
911	5.5.4(4)(f)(i)	matters the auditor was engaged to audit included the matters specified in clause 5.5.3; and	Application	Chapter 3, Appendix A	Section 3.4	
912	5.5.4(4)(f)(ii)	auditor was instructed to report on at least the matters described in clause 5.1.4; and	Application	Chapter 3, Appendix A	Section 3.4	
913	5.5.4(4)(g)	that the-	Application	Chapter 3, Appendix A	Section 3.4	
914	5.5.4(4)(g)(i)	audit report provided pursuant to clause 5.1.4;	Application	Chapter 3, Appendix A	Section 3.4	
915	5.5.4(4)(g)(ii)	verification report; and	Application	Chapter 3, Appendix A	Section 3.4	
916	5.5.4(4)(g)(iii)	other certifications required by this clause,	Application	Chapter 3, Appendix A	Section 3.4	
917		all relate to the same CPP proposal.	Application	Chapter 3, Appendix A	Section 3.4	
918	5.5.4(5)	Where-	N / A			Not applicable (obligation arises post submission)
919	5.5.4(5)(a)	a director has certified a matter of opinion in accordance with this clause; and	N / A			
920	5.5.4(5)(b)	his or her opinion has changed before the Commission's determination of the CPP in question,	N / A			
921		that director must notify the Commission as soon as reasonably practicable.	N / A			
922	5.5.4(6)	Where-	N / A			Not applicable (obligation arises post submission)
923	5.5.4(6)(a)	a director has certified a matter of fact in accordance with this clause; and	N / A			
924	5.5.4(6)(b)	before the Commission's determination of the CPP in question he or she-	N / A			
925	5.5.4(6)(b)(i)	becomes aware that the fact is untrue; or	N / A			
926	5.5.4(6)(b)(ii)	has significant cause to doubt the accuracy of that fact,	N / A			
927		that director must notify the Commission as soon as reasonably practicable.	N / A			
928	5.5.4(7)	For the avoidance of doubt, the certifications required by the different subclauses of this clause may be made by the same or different directors.	N / A			
929	**SCHEDULE G Terms of reference for verifiers**					
930	G1	**Interpretation**				
931	G1(1)	Words in bold in this schedule that are defined in another schedule bear the same meanings as specified in that other schedule.				

Compliance Checklist (IM Part 5)

932	G1(2)	Any requirement to provide an opinion, report on or consider a particular matter must be construed as-				
933	G1(2)(a)	requiring consideration only of the material identified by the requirement in question; and				
934	G1(2)(b)	a requirement to provide the opinion or report on the matter in the verification report.				
935	G2	**Verifier's role, purpose and obligations**				
936		The verifier's role, purpose and obligations include-				
937	G2(a)	engaging with the CPP applicant in an independent manner in accordance with this Terms of Reference;	IV Report	Appendix H		
938	G2(b)	assessing the extent to which the CPP applicant's policies allow the CPP applicant to meet the expenditure objective;	IV Report	Chapter 1, 4 & 5	Sections 1.5.2 to 1.5.5, 4.2, 5.2	
939	G2(c)	assessing the extent to which the CPP applicant's policies have been implemented;	IV Report	Chapter 1	Section 1.5.2	
940	G2(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);	IV Report	Chapter 1	Section 1.5.2	
941	G2(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;	IV Report	Chapter 1	Sections 1.5.2 to 1.5.5	
942	G2(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;	IV Report	Chapter 1	Section 1.5.2, 1.5.6	
943	G2(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	IV Report	Chapter 1	Sections 1.5.2, 1.5.8, 3.3.1, 3.3.2, 3.3.3, 3.3.4	
944	G2(h)	providing a list of the key issues which it considers the Commission should focus on when assessing the CPP proposal.	IV Report	Chapters 1, 7	Section 1.5.10, Table 7.1	
945	G3	**Service measures, levels and quality standards**				
946	G3(1)	The verifier must review, assess and report on-				
947	G3(1)(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;	IV Report	Chapter 3	Sections 3.1.2, 3.1.3, 3.1.4	
948	G3(1)(b)	whether the CPP applicant has undertaken an appropriate process to determine the service measures and service levels, such as consultation with relevant consumers;	IV Report	Chapter 3	Sections 3.1.2, 3.1.3, 3.1.4, 3.2.1, 3.2.2, 3.2.3, 3.2.4	
949	G3(1)(c)	whether any step change in any service level is explained and justified; and	IV Report	Chapter 3	Sections 3.2.2, 3.2.3, 3.2.4	
950	G3(1)(d)	the extent and effectiveness of a CPP applicant's consultation with its consumers, as specified in clause 5.5.1.	IV Report	Chapter 3	Sections 3.3.1, 3.3.2, 3.3.3, 3.3.4	
951	G3(2)	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.	IV Report	Chapter 3	Sections 3.4.1, 3.4.2, 3.4.3, 3.4.4	
952	G4	**Selection of identified programmes**				
953	G4(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 programmes to be 'identified programmes'.	IV Report	Appendix B		
954	G4(2)	In determining which, and how many, projects or programmes to select as identified programmes, the verifier must consider–	IV Report	Appendix B		
955	G4(2)(a)	the long term interests of consumers;	IV Report	Appendix B	Section B.3	
956	G4(2)(b)	the Commission's ability to effectively review whether the CPP applicant's capex forecast and opex forecast are consistent with the expenditure objective;	IV Report	Appendix B	Section B.3	
957	G4(2)(c)	the CPP applicant's rationale for seeking a CPP;	IV Report	Appendix B	Section B.3	
958	G4(2)(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-	IV Report	Appendix B	Section B.3	
959	G4(2)(d)(i)	in aggregate; and	IV Report	Appendix B	Section B.3	
960	G4(2)(d)(ii)	for each of the capex categories;	IV Report	Appendix B	Section B.3	
961	G4(2)(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-	IV Report	Appendix B	Section B.3	
962	G4(2)(e)(i)	in aggregate; and	IV Report	Appendix B	Section B.3	
963	G4(2)(e)(ii)	for each of the opex categories;	IV Report	Appendix B	Section B.3	

964	G4(2)(f)	its ability to assess any quality standard variation proposed; and	IV Report	Appendix B	Section B.3	
965	G4(2)(f)(g)	the materiality of the programmes or projects to the CPP proposal, the capex forecast and the opex forecast.	IV Report	Appendix B	Section B.3	
966	G4(3)	The identified programmes selected in accordance with subclause (1) must address-	IV Report	Appendix B	Section B.3	
967	G4(3)(a)	a key risk that the CPP applicant is exposed to;	IV Report	Appendix B	Section B.3	
968	G4(3)(b)	a key driver of the need to submit a CPP proposal; or	IV Report	Appendix B	Section B.3	
969	G4(3)(c)	an obligation that has a significant impact in the context of the CPP applicant's overall business.	IV Report	Appendix B	Section B.3	
970	G4(4)	The verifier must-	IV Report	Appendix B	Section B.2	
971	G4(4)(a)	notify the CPP applicant of its selected projects or programmes; and	IV Report	Appendix B	Section B.2	
972	G4(4)(b)	not change its selection after such notification.	IV Report	Appendix B	Section B.2	
973	G5	**Capex forecast**				
974	G5(1)	The verifier must-				
975	G5(1)(a)	provide an opinion as to whether the-	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
976	G5(1)(a)(i)	policies;	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
977	G5(1)(a)(ii)	planning standards; and	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
978	G5(1)(a)(iii)	key assumptions,	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
979		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;	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
980	G5(1)(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;	IV Report	Chapter 4, Appendix C	Sections 4.2.1, 4.2.2, 4.2.3	
981	G5(1)(c)	provide an opinion on the reasonableness of the key assumptions relevant to capex relied upon the CPP applicant including-	IV Report	Chapter 4, Appendix C	Sections 4.3.1, 4.3.2, 4.3.3, 6.4.1, 6.4.2, 6.4.3, 6.4.4	
982	G5(1)(c)(i)	the method and information used to develop them;	IV Report	Chapter 4, Appendix C	Sections 4.3.1, 4.3.2, 4.3.3, 6.4.1, 6.4.2, 6.4.3, 6.4.4	
983	G5(1)(c)(ii)	how they were applied; and	IV Report	Chapter 4, Appendix C	Sections 4.3.1, 4.3.2, 4.3.3, 6.4.1, 6.4.2, 6.4.3, 6.4.4	
984	G5(1)(c)(iii)	their effect or impact on the capex forecast by comparison to their effect or impact on actual capex;	IV Report	Chapter 4, Appendix C	Sections 4.3.1, 4.3.2, 4.3.3, 6.4.1, 6.4.2, 6.4.3, 6.4.4	
985	G5(1)(d)	report conclusions of a detailed review of identified programmes that are capex projects or capex programmes including, but not limited to assessment of-	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
986	G5(1)(d)(i)	whether relevant policies and planning standards were applied appropriately;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
987	G5(1)(d)(ii)	whether policies regarding the need for, and prioritisation of, the project or programme are reasonable and have been applied appropriately;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
988	G5(1)(d)(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 Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
989	G5(1)(d)(iv)	the approach used to prioritise capex projects over time including the application of that approach for the next period;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
990	G5(1)(d)(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;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
991	G5(1)(d)(vi)	the impact on other cost categories including the relationship with opex;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
992	G5(1)(d)(vii)	links with other projects;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
993	G5(1)(d)(viii)	cost control and delivery performance for actual capex;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
994	G5(1)(d)(ix)	the efficiency of the proposed approach to procurement; and	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	

995	G5(1)(d)(x)	whether it should be included as a contingent project or part of a contingent project;	IV Report	Chapter 4, Appendix C	Sections 4.4.1, 4.4.2, 4.4.3	
996	G5(1)(e)	provide an opinion as to overall deliverability of work covered by the capex categories in the next period; and	IV Report	Chapter 4, Appendix C	Sections 4.5.1, 4.5.2, 4.5.3	
997	G5(1)(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-	IV Report	Chapter 4, Appendix C	Sections 4.6.1, 4.6.2, 4.6.3	
998	G5(1)(f)(i)	the inputs used within the model; and	IV Report	Chapter 4, Appendix C	Sections 4.6.1, 4.6.2, 4.6.3	
999	G5(1)(f)(ii)	the methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.	IV Report	Chapter 4, Appendix C	Sections 4.6.1, 4.6.2, 4.6.3	
1000	G5(2)	Based on its analysis under this clause the verifier must provide its opinion on whether the applicant's forecast of total capex meets the expenditure objective and, if not identify-	IV Report	Chapter 4, Appendix C	Sections 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.4.1, 4.4.2, 4.4.3	
1001	G5(2)(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;	IV Report	Chapter 4, Appendix C	Sections 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.4.1, 4.4.2, 4.4.3	
1002	G5(2)(b)	which of the CPP applicant's forecast capex programmes for each capex category might warrant further assessment by the Commission; and	IV Report	Chapter 4, Appendix C	Sections 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.4.1, 4.4.2, 4.4.3	
1003	G5(2)(c)	what type of assessment would be the most effective.	IV Report	Chapter 4, Appendix C	Sections 4.1.1, 4.1.2, 4.1.3, 4.1.4, 4.4.1, 4.4.2, 4.4.3	
1004	G6	**Opex forecast**				
1005	G6(1)	The verifier must-				
1006	G6(1)(a)	provide an opinion as to whether the-	IV Report	Chapter 5, Appendix C	Sections 5.2.1, 5.2.2, 5.2.3	
1007	G6(1)(a)(i)	policies;	IV Report	Chapter 5, Appendix C	Sections 5.2.1, 5.2.2, 5.2.3	
1008	G6(1)(a)(ii)	planning standards; and	IV Report	Chapter 5, Appendix C	Sections 5.2.1, 5.2.2, 5.2.3	
1009	G6(1)(a)(iii)	key assumptions,	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1010		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;	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1011	G6(1)(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;	IV Report	Chapter 5, Appendix C	Sections 5.2.1, 5.2.2, 5.2.3	
1012	G6(1)(c)	provide an opinion on the reasonableness of the key assumptions relevant to opex relied upon by the CPP applicant including-	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1013	G6(1)(c)(i)	the method and information used to develop them;	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1014	G6(1)(c)(ii)	how they have been applied; and	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1015	G6(1)(c)(iii)	their effect or impact on the opex forecast by comparison to their effect or impact on actual opex;	IV Report	Chapter 5, Appendix C	Sections 5.3.1, 5.3.2, 5.3.3	
1016	G6(1)(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;	IV Report	Chapter 5, Appendix C	Sections 5.4.1, 5.4.2, 5.4.3	
1017	G6(1)(e)	provide an opinion as to the reasonableness of the methodology used in forecasting opex (such as cost benchmarking or internal historic cost trending), including the relationship between the opex forecast and capex forecast;	IV Report	Chapter 5, Appendix C	Sections 5.8.1, 5.8.2, 5.8.3	
1018	G6(1)(f)	provide an opinion as to the reasonableness of any opex reduction initiatives undertaken or planned during the current period or the next period;	IV Report	Chapter 5, Appendix C	Sections 5.6.1, 5.6.2, 5.6.3	
1019	G6(1)(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-	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1020	G6(1)(g)(i)	whether relevant policies and planning standards were applied appropriately;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1021	G6(1)(g)(ii)	whether policies regarding the need for, and prioritisation of, the project or programme are reasonable and have been applied appropriately;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	

1022	G6(1)(g)(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 Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1023	G6(1)(g)(iv)	the approach used to prioritise opex projects over time including the application of that approach for the next period;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1024	G6(1)(g)(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;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1025	G6(1)(g)(vi)	the impact on other cost categories including the relationship with capex;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1026	G6(1)(g)(vii)	links with other projects;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1027	G6(1)(g)(viii)	cost control and delivery performance for actual opex;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1028	G6(1)(g)(ix)	the efficiency of the proposed approach to procurement; and	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1029	G6(1)(g)(x)	whether it should be included as a contingent project or part of a contingent project;	IV Report	Chapter 5, Appendix C	Sections 5.5.1, 5.5.2, 5.5.3	
1030	G6(1)(h)	provide an opinion as to overall deliverability of work covered by the opex categories in the next period; and	IV Report	Chapter 5, Appendix C	Sections 5.7.1, 5.7.2, 5.7.3	
1031	G6(1)(h)(i)	provide an opinion as to the reasonableness and adequacy of any opex models used to prepare the opex forecast including an assessment of-	IV Report	Chapter 5, Appendix C	Sections 5.8.1, 5.8.2, 5.8.3	
1032	G6(1)(h)(i)(i)	the inputs used within the model; and	IV Report	Chapter 5, Appendix C	Sections 5.8.1, 5.8.2, 5.8.3	
1033	G6(1)(h)(i)(ii)	any methods the CPP applicant used to check the reasonableness of the forecasts and related expenditure.	IV Report	Chapter 5, Appendix C	Sections 5.8.1, 5.8.2, 5.8.3	
1034	G6(2)	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-	IV Report	Chapter 5, Appendix C	Sections 5.1.1, 5.1.2, 5.1.3, 5.1.4	
1035	G6(2)(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;	IV Report	Chapter 5, Appendix C	Sections 5.1.1, 5.1.2, 5.1.3, 5.1.4	
1036	G6(2)(b)	which of the CPP applicant's forecast opex programmes for each opex category might warrant further assessment by the Commission; and	IV Report	Chapter 5, Appendix C	Sections 5.1.1, 5.1.2, 5.1.3, 5.1.4	
1037	G6(2)(c)	what type of assessment would be the most effective.	IV Report	Chapter 5, Appendix C	Sections 5.1.1, 5.1.2, 5.1.3, 5.1.4	
1038	G7	**Capital contributions**				
1039		The verifier must provide an opinion as to whether the forecast of capital contributions-	IV Report	Chapter 6	Sections 6.1.1, 6.1.2, 6.1.3, 6.1.4	
1040	G7(a)	is reasonable; and	IV Report	Chapter 6	Sections 6.1.1, 6.1.2, 6.1.3, 6.1.4	
1041	G7(b)	consistent with other aspects of the CPP proposal, in particular-	IV Report	Chapter 6	Sections 6.1.1, 6.1.2, 6.1.3, 6.1.4	
1042	G7(b)(i)	the capex forecast; and	IV Report	Chapter 6	Sections 6.1.1, 6.1.2, 6.1.3, 6.1.4	
1043	G7(b)(ii)	forecast demand data provided in accordance with clause D6.	IV Report	Chapter 6	Sections 6.1.1, 6.1.2, 6.1.3, 6.1.4	
1044	G8	**Demand forecasts**				
1045	G8(1)	The verifier must provide an opinion as to whether-	IV Report	Chapter 6	Sections 6.2.1, 6.2.2, 6.2.3, 6.2.4	
1046	G8(1)(a)	the key assumptions, key input data and forecasting methods used in determining demand forecasts were reasonable; and	IV Report	Chapter 6	Sections 6.2.1, 6.2.2, 6.2.3, 6.2.4	
1047	G8(1)(b)	it was appropriate to use the demand forecasts resulting from these methods and assumptions to determine the-	IV Report	Chapter 6	Sections 6.2.1, 6.2.2, 6.2.3, 6.2.4	
1048	G8(1)(b)(i)	capex forecast; and	IV Report	Chapter 6	Sections 6.2.1, 6.2.2, 6.2.3, 6.2.4	
1049	G8(1)(b)(ii)	opex forecast.	IV Report	Chapter 6	Sections 6.2.1, 6.2.2, 6.2.3, 6.2.4	
1050	G9	**Assessment techniques**				
1051	G9(1)	When-	IV Report	Appendix A	Section A.1	
1052	G9(1)(a)	undertaking analysis and reviews of information; and	IV Report	Appendix A	Section A.1	
1053	G9(1)b)	considering the matters,	IV Report	Appendix A	Section A.1	
1054		required by this Schedule, the verifier must use some or all of the following assessment techniques:	IV Report	Appendix A	Section A.1	
1055	G9(1)(c)	process benchmarking;	IV Report	Appendix A	Section A.1	

1056	G9(1)(d)	process or functional modelling;	IV Report	Appendix A	Section A.1	
1057	G9(1)(e)	unit rate benchmarking;	IV Report	Appendix A	Section A.1	
1058	G9(1)(f)	trending or time-series analysis;	IV Report	Appendix A	Section A.1	
1059	G9(1)(g)	high level governance and process reviews;	IV Report	Appendix A	Section A.1	
1060	G9(1)(h)	internal benchmarking of forecast costs against costs in the current period;	IV Report	Appendix A	Section A.1	
1061	G9(1)(I)	capex category and opex category benchmarking;	IV Report	Appendix A	Section A.1	
1062	G9(1)(j)	project and programme sampling; and	IV Report	Appendix A	Section A.1	
1063	G9(1)(k)	critiques or independent development of-	IV Report	Appendix A	Section A.1	
1064	G9(1)(k)(i)	demand forecasts;	IV Report	Appendix A	Section A.1	
1065	G9(1)(k)(ii)	labour unit cost forecasts;	IV Report	Appendix A	Section A.1	
1066	G9(1)(k)(iii)	materials forecasts;	IV Report	Appendix A	Section A.1	
1067	G9(1)(k)(iv)	plant forecasts; and	IV Report	Appendix A	Section A.1	
1068	G9(1)(k)(v)	equipment unit cost forecasts.	IV Report	Appendix A	Section A.1	
1069	G9(2)	The verifier must explain why particular techniques listed in subclause (1) were applied and others were not applied.	IV Report	Appendix A	Section A.1	
1070	G9(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-	IV Report	Appendix A	Section A.1	
1071	G9(3)(a)	describe in the draft verification report its nature and source and the reason for wishing to rely on it;	IV Report	Appendix A	Section A.1	
1072	G9(3)(b)	subject to subclause (4), provide it to the CPP applicant;	IV Report	Appendix A	Section A.1	
1073	G9(3)(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	IV Report	Appendix A	Section A.1	
1074	G9(3)(d)	where, notwithstanding paragraph (c), the verifier continues to rely on it, describe in the verification report-	IV Report	Appendix A	Section A.1	
1075	G9(3)(d)(i)	the nature and source of the information relied upon and the reason for relying on it; and	IV Report	Appendix A	Section A.1	
1076	G9(3)(d)(ii)	the CPP applicant's concerns in respect thereof.	IV Report	Appendix A	Section A.1	
1077	G9(4)	Subclause (3)(b) does not apply if the verifier's terms of use of the information prevent such disclosure.	IV Report	Appendix A	Section A.1	
1078	G10	**Contingent projects**	Application	Appendix V		There are no contingent projects in our CPP proposal
1079	G10(1)	For each proposed contingent project, the verifier must provide an opinion as to whether that project satisfies the following criteria:	IV Report	Chapter 6	Section 6.3	
1080	G10(1)(a)	it is-	IV Report	Chapter 6	Section 6.3	
1081	G10(1)(a)(i)	reasonably required of an EDB in meeting the expenditure objective; and	IV Report	Chapter 6	Section 6.3	
1082	G10(1)(a)(ii)	one that associated assets are likely to be commissioned,	IV Report	Chapter 6	Section 6.3	
1083		during the CPP regulatory period;	IV Report	Chapter 6	Section 6.3	
1084	G10(1)(b)	a commencement date cannot be forecast with an appropriate degree of specificity by comparison with other proposed projects;	IV Report	Chapter 6	Section 6.3	
1085	G10(1)(c)	the total of capex forecast and opex forecast in relation to the project-	IV Report	Chapter 6	Section 6.3	
1086	G10(1)(c)(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;	IV Report	Chapter 6	Section 6.3	
1087	G10(1)(c)(ii)	is reasonable in dollar terms; and	IV Report	Chapter 6	Section 6.3	
1088	G10(1)(c)(iii)	would be likely, when forecast with reasonable certainty, to meet the expenditure objective.	IV Report	Chapter 6	Section 6.3	
1089	G10(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).	IV Report	Chapter 6	Section 6.3	
1090	G11	**Completeness of CPP proposal**				
1091		A verification report must-				
1092	G11(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;	IV Report	Chapter 7, Appendix I	Section 7.1	Appendix I of the IV Report lists the information provided by Aurora that the Verifier relied upon in preparing its verification report, including any information used that was not provided to the Verifier by Aurora (e.g. information disclosures published by the Commission).

1093	G11(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;	IV Report	Chapters 1, 3, 4, 5, 6, 7	Sections 1.5.9, 7.1	Each chapter in the IV Report on service measures, levels and quality standards, capex, opex, demand, capital contributions and contingent projects indenfies information the Verifier considers is omitted, incomplete or insufficient.
1094	G11(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;	IV Report	Chapters 1, 3, 4, 5, 6, 7	Sections 1.5.9, 7.1	Each chapter in the IV Report on service measures, levels and quality standards, capex, opex, demand, capital contributions and contingent projects indenfies the nature of any information required to fulfil the information requirements in question.
1095	G11(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	IV Report	Chapters 1, 3, 4, 5, 6, 7	Sections 1.5.9, 7.1	Each chapter in the IV Report on service measures, levels and quality standards, capex, opex, demand, capital contributions and contingent projects indenfies the extent to which the omission, incompleteness or insufficiency of information has impaired the Verifier's verification.
1096	G11(e)	explain why the verifier has selected the identified programmes in accordance with clause G4(1).	IV Report	Chapter 7, Appendix B	Sections 7.1, B.3	
1097	G12	**Overview of key issues and additional information requirements**				
1098		Based on its assessment, the verifier must, in the verification report-	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	
1099	G12(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;	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	
1100	G12(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	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	
1101	G12(c)	identify any other information it reasonably believes would-	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	
1102	G12(c)(i)	be held by the CPP applicant; and	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	
1103	G12(c)(ii)	assist the Commission’s assessment of the CPP proposal.	IV Report	Chapters 1, 7	Sections 1.5.10, 7.1	

Appendix U. Compliance Checklist (IM Schedule D)

993. This compliance matrix provides a look-up reference for information that is required to supplement the Commission's Information Disclosure requirements for Asset Management Plans. The reference numbers are consistent with the clause numbers in Schedule D of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated at 29 January 2020).

Compliance Checklist (IM Schedule D)

Index	IM Clause	Description	Addressed by	Document reference	Section reference	Comments
1	SCHEDULE D	CAPITAL AND OPERATING EXENDITURE INFORMATION				
2	D1	**Interpretation**				
3	D2	**Instructions relating to provision of information**				
4	D2(1)	CPP proposal must-				
5	D2(1)(a)	include all information required in-				
6	D2(1)(a)(i)	Attachment A of the ID determination or any successor to that Attachment A, except where limited by subclause (5); and	2020 AMP	Appendix G		
7	D2(1)(a)(ii)	this schedule;	Application	Appendix U		
8		unless the Commission has approved a modification or exemption from the CPP application requirements under clause 5.1.6 and has included the relevant information related to the exemption or modification as set out in clause 5.1.8;				
9	D2(1)(b)	contain a table that, in respect of each clause of this schedule-	Application	Appendix U		
10	D2(1)(b)(i)	provides a reference to the place where, in the CPP proposal, a response is provided; and	Application	Appendix U		
11	D2(1)(b)(ii)	gives the title and page reference to any separate document identified in response, including in the case where the document in question is provided in the CPP proposal.	Application	Appendix U		
12	D2(2)	Where information provided in accordance with these requirements differs from the most recent information provided by the EDB to the Commission in accordance with any obligation under Part 4 of the Act, a CPP proposal must-	2020 AMP	Appendix D	Table D.2	
13	D2(2)(a)	identify the differences; and	2020 AMP	Appendix D	Table D.2	
14	D2(2)(b)	give reasons for such differences.	2020 AMP	Appendix D	Table D.2	
15	D2(3)	Where information required by this schedule is omitted from a CPP proposal, the CPP proposal must contain an explanation for each such omission.	Application	Appendix V		Not applicable - no information required in Schedule D has been omitted from Aurora's CPP proposal
16	D2(4)	A CPP applicant may comply with subclause (1) by-				
17	D2(4)(a)	reproducing and providing its asset management plan with the additional material required by this schedule included; or	2020 AMP Application	Appendix G Appendix U		Appendix G of the AMP provides a look-up reference for each of the Commerce Commission's information disclosure requirements under Attachment A of the ID Determination. This table provides a look-up reference for each of the Commission's Schedule D IM requirements.
18	D2(4)(b)	providing the information required by this schedule separately from its asset management plan.	Application Financial/Model report SharePoint data room IV material (relied upon)			In order to comply with subclause (1) we have provided additional material required by this schedule in both our AMP and other documents (including Application, Financial/Model report and SharePoint data room).
19	D2(5)	For the purpose of subclause 3.4 of Attachment A of the ID determination, additional information required to be included in the CPP proposal need only apply to the-				
20	D2(5)(a)	current period;	Application	Appendices D to J		
21	D2(5)(b)	assessment period; and	2020 AMP Application	Chapter 1 Chapter 3, Appendices R and S	Section 1.1.2 Section 3.5	We note that the AMP covers a 10-year period from 1 April 2020 to 31 March 2030. This includes the assessment period and the next period. We note that the Commission has approved a modification to the definition of "assessment period" to mean the period between 31 March 2019 and the EDB's anticipated commencement date of the CPP (i.e. RY20 and RY21).
22	D2(5)(c)	next period.	2020 AMP	Chapter 1	Section 1.1.2	The AMP covers a 10-year period from 1 April 2020 to 31 March 2030. This includes the assessment period and the next period.

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23	D2(6)	Detailed information described in clause D10 in relation to identified programmes				
24	D2(6)(a)	need only be provided to the verifier upon the verifier's request; and	IV Report	Appendix I		All documents provided to the Verifier are in the SharePoint site and documented in the Independent Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. Chapter 2.3 describes the process of document and information submission
25	D2(6)(b)	where provided under (a), must be included in the CPP proposal as provided to the Commission in the CPP application.	IV Report	Appendices C & I		All documents provided to the Verifier are in the SharePoint site and documented in the Independent Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. Chapter 2.3 describes the process of document and information submission Appendix C of the IV Report lists the selected projects, including the relevant documents for each selected project.
26	D3	**Governance, organisation structure and business processes**				
27	D3(1)	In addition to the information required by clause 3.7 of Attachment A of the ID determination, provide-				
28	D3(1)(a)	the current organisational structure of the EDB and a description of any separate organisation used to manage capex and opex;	Application 2020 AMP	Chapter 4, Appendix P Chapter 2	Section 4.5	
29	D3(1)(b)	the number of full time equivalent employees, employed by the applicant, broken down by business units;	Application SharePoint Data Room	Chapter 4, Appendix P E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf	Section 4.5	Further information in relation to Aurora's organisation structure was provided to the Verifier in response to questions asked by the Verifier. Table I.2 of the Verifier Report sets out our responses to those questions.
30	D3(1)(c)	an explanation of the arrangements for undertaking system operations and network support activities, and the extent that these functions are centralised and outsourced;	2020 AMP	Chapters 5	Sections 5.2.2	
31	D3(1)(d)	where any cost is shared with organisational activities that do not involve providing regulated electricity distribution services, the basis on which these costs have been allocated and included in the forecast; and	Application Financial/Model report	Appendix N Section 6.1		
32	D3(1)(e)	a description of any anticipated changes during the next period to the organisational structure.	Application	Appendix P		We have no planned changes to our organisational structure during the next period, other than the secondments to the 12 Month Programme Team (Works Planning & Delivery), returning to their home division (Technology & Information)
33	D3(2)	In addition to the information required by clause 3.12 of Attachment A of the ID determination-				
34	D3(2)(a)	provide a commentary on the sources of asset management information; and	2020 AMP	Chapters 5, 9, Appendix E	Sections 5.2.3, 9.3	
35	D3(2)(b)	other relevant data that has been relied upon in preparing the forecasts, including-	2020 AMP	Chapters 5, 9, Appendix E	Sections 5.2.3, 9.3	
36	D3(2)(b)(i)	a description of the quality of this information and data; and	2020 AMP	Chapters 5, 9, Appendix E	Sections 5.2.3, 9.3	
37	D3(2)(b)(ii)	details of any assumptions that have been made to fill any information or data gaps.	2020 AMP	Chapters 5, 9, Appendix E	Sections 5.2.3, 9.3	
38	D3(3)	In addition to the information required by clause 3.13 of Attachment A of the ID determination, describe the procedures and processes used by the EDB to-				
39	D3(3)(a)	plan and develop;	2020 AMP Application	Chapter 6 Appendices B, D	Section 6.2.2 Sections B.5.4, D.3.1, D.4.1	

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40	D3(3)(b)	estimate the cost of;	Application 2020 AMP	Appendices D, E, F, G, H, I Chapter 6	Sections D.5, E.3.2, E.4.2, E.5.2, E.6.2, E.7.2, E.8.2, E.8.6, E.8.11, E.9.2, E.9.6, F.2.2, G.4.2, G.5.2, G.6.2, G.7.2, H.3.2, H.4.2, H.5.2, H.6.2, I.4.2, I.6.2, I.7.2, I.8.2, I.9.2, J.4.2 Section 6.2.2	
41	D3(3)(c)	approve;	Application	Appendices B, D	Sections B.3.1, B.3.3, D.3.1, D.4.1	
42	D3(3)(d)	implement; and	Application	Appendix M	Sections M.1 - M.4	
43	D3(3)(e)	monitor;	Application 2020 AMP	Appendices B, M Chapter 7	Sections B.4.1, M.4 Section 7.2.1	
44		the capex and opex projects and programmes described in the CPP proposal, and develop unit costs.				
45	D3(4)	In addition to the information required by clause 3.7 of Attachment A of the ID determination provide-				
46	D3(4)(a)	an overview of any internal challenge, review and approval process applied before the forecasts were finalised for inclusion in the CPP proposal;	Application	Appendix B	Section B.3.3	
47	D3(4)(b)	a statement as to whether or not the forecast includes provision for efficiency improvements over time and, if so, a description of how this provision is reflected in the forecasts; and	Application	Appendix D	Section D.5.8	
48	D3(4)(c)	a statement of how the approval process treats the risks on cost estimates and timing of projects due to deviations of forecast assumptions.	2020 AMP	Chapter 4	Section 4.8.3	
49	D4	**Network asset information**				
50		In relation to the information required by clause 4 of Attachment A of the ID determination-				
51	D4(a)	where information is based on estimates, this must be explicitly stated; and	2020 AMP	Chapters 3, 8	Section 3.7	An overview of network assets is provided in Section 3.7, with Chapter 8 providing a more detailed description for each fleet. Where information is based on estimates, this is indicated in Chapter 8.
52	D4(b)	quantities of assets must be presented in a way that clearly describes the size and scope of regulated assets, but need not include detailed lists or schedules as would be included in a complete asset register or inventory.	2020 AMP	Chapters 3, 8	Sections 3.7, 8.1.4, 8.1.12, 8.2.4, 8.2.11, 8.2.18, 8.3.4, 8.3.12, 8.3.19, 8.4.2.2, 8.4.4.2, 8.4.5.2, 8.4.6.2, 8.4.7.2, 8.5.2.2, 8.5.3.2, 8.5.4.2, 8.5.5.2, 8.5.6.2, 8.5.7.2, 8.6.4, 8.6.12, 8.6.20, 8.6.28, 8.7.4, 8.7.11, 8.7.18, 8.7.25	An overview of network assets is provided in Section 3.7, with Chapter 8 providing a more detailed description for each fleet.
53	D5	**Service Levels**				
54		Where not included in information provided in respect of clause 5 of Attachment A of the ID determination, provide-				

55	D5(a)	a description as to how each performance indicator and performance target described in accordance with clause 5 of Attachment A of the ID determination-	Application 2020 AMP	Appendix L Chapter 4	Section L.6 Sections 4.6.1, 4.6.2	
56	D5(a)(i)	relates to the EDB's relevant policies; and	Application 2020 AMP	Appendix L Chapter 4	Section L.6 Sections 4.6.1, 4.6.2	
57	D5(a)(ii)	reflects the expenditure objective;	Application 2020 AMP	Appendix L Chapter 4	Section L.11 Sections 4.6.1, 4.6.2	
58	D5(b)	for each performance indicator identified and defined in accordance with subclause (a):				
59	D5(b)(i)	the measured performance for each year of the current period; and	Application 2020 AMP SharePoint data room	Appendix L Chapter 4 IP-1246 Aurora-Energy-2018-AMP-UPDATED for 2019.pdf	Section L.2 Sections 4.6.1, 4.6.2	Note that a new system for recording and analysing health and safety incidents was established in July 2017, following our separation from Delta. The data for previous years was collected and analysed on a different basis from our current approach, and the results are not directly comparable with the data we have recorded since July 2017. Accordingly, it has not been possible to provide the measured performance for health and safety for years 2015 to 2017. For further information, refer to pages 70-71 of the 2018 AMP.
60	D5(b)(ii)	the target performance for each year of the next period;	Application 2020 AMP	Appendix L Chapter 4	Section L.7 Sections 4.6.1, 4.6.2	
61	D5(c)	a comparison and evaluation of each actual service level achieved for the disclosure years in the current period against each relevant performance target, including explanations for all significant variances.	Application	Appendix L	Section L.2	Refer to comment above at D5(b)(i) in relation to health and safety performance data for years 2015 to 2017.
62	D6	**Network development planning**				
63	D6(1)	The description of network development plans required in clause 11 of Attachment A of the ID determination must include the additional information specified in this clause.				
64	D6(2)	For system growth capex, connection capex, asset relocation capex and reliability, safety and environment capex-				
65	D6(2)(a)	identify all relevant documents, policies and consultants' reports that were taken into account in preparing these capex forecasts; and	SharePoint data room	IPC-980 AE-Policy-04 - Asset Management IPC-981 AE-Policy-01 - Health and Safety IPL758 AE-S010-Capital Contributions-v1.3 IPL-1200 Aurora Energy Network Evolution Roadmap-r11.pdf IP2-92 Demand Forecast Model_manual_v2.0.pdf		Refer to WSP's Independent Review of Electricity Networks - Aurora. A copy of this document is available on Aurora's website at: https://www.auroraenergy.co.nz/about/independent-review/ In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. We have provided examples of the relevant documents/policies/reports under the "document reference" column.
66	D6(2)(b)	where appropriate, identify their relevance to each category of capex.				

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67	D6(3)	In addition to the information required by clauses 11.1-11.6 of Attachment A of the ID determination, provide the rationale for the planning criteria and other key drivers and assumptions for network development for system growth capex, connection capex, asset relocation capex and reliability, safety and environment capex.	Application	Appendices F & G	Sections F.2.1, G.1, G.4.1, G.5.1, G.6.1	
68	D6(4)	In addition to the information required by clause 11.7 of Attachment A of the ID determination, provide the rationale for the prioritisation process and criteria.	2020 AMP	Chapter 6	Section 6.2.2	
69	D6(5)	In addition to the information on demand forecasts required by clause 11.8 of Attachment A of the ID determination-				
70	D6(5)(a)	describe and explain the methodology used to prepare the relevant forecasts, including-	2020 AMP	Chapter 6	Section 6.3.1	
71	D6(5)(a)(i)	any sensitivity analysis undertaken;	2020 AMP	Chapter 6	Section 6.3.1	
72	D6(5)(a)(ii)	any weather normalisation methodology used and how weather data has been used; and	2020 AMP	Chapter 6	Section 6.3.1	
73	D6(5)(a)(iii)	the models used (including each model's key inputs and assumptions); and	2020 AMP	Chapter 6	Section 6.3.1	
74	D6(5)(b)	provide-				
75	D6(5)(b)(i)	an outline of the treatment of very large loads, uncertain loads and significant loads transferred, or expected to be transferred, between different parts of the network (e.g. between zone substations and/or between feeders);	2020 AMP	Chapter 6	Section 6.3.1	
76	D6(5)(b)(ii)	details of the location, types and aggregate levels of any distributed generation and assumptions relating to the impact they may have on network forecasts; and	SharePoint data room 2020 AMP	IP2-92 Demand Forecast Model_manual_v2.0.pdf Chapter 3	Section 3.4	
77	D6(5)(b)(iii)	details of the effect that any demand management systems or initiatives and any other new or emerging technologies may have on the network forecasts and the extent that they have been included in the forecasts in the CPP proposal.	2020 AMP	Chapter 6	Sections 6.3.1, 6.4.1, 6.4.2	
78	D6(6)	For the forecasts of consumer connections, embedded generation and electricity volumes provided in the relevant templates in Schedule E-				
79	D6(6)(a)	describe and explain the methodology used to prepare the relevant forecasts including-	2020 AMP	Chapter 6	Section 6.3.4	
80	D6(6)(a)(i)	any sensitivity analysis undertaken;	2020 AMP	Chapter 6	Section 6.3.4	Not applicable - Aurora does not conduct sensitivity analysis for these forecasts
81	D6(6)(a)(ii)	any weather normalisation methodology used and how weather data has been used; and	2020 AMP	Chapter 6	Section 6.3.4	Not applicable - Aurora does not conduct weather normalisation / impact analysis for these forecasts
82	D6(6)(a)(iii)	the models used (including each model's key inputs and assumptions);	2020 AMP	Chapter 6	Section 6.3.4	
83	D6(7)	In addition to the information required by clause 11.9 of Attachment A of the ID determination, provide-				
84	D6(7)(a)	for system growth capex, a description of, and the rationale for, the planning standards, and key assumptions relied on by the EDB in determining the need to augment its network;	2020 AMP Application	Chapter 6 Appendix F	Section 6.2 .1 Section F.2	
85	D6(7)(b)	for reliability, safety and environment capex, a description of any models developed by or for the EDB to determine the reliability, safety and environment capex including the rationale for all key input assumptions; and	2020 AMP Application	Chapter 6 Appendix G	Section 6.7.1	
86	D6(7)(c)	for connection capex and asset relocation capex-	2020 AMP Application	Chapters 5, 6 Appendix G	Sections G.4 and G.5	

87	D6(7)(c)(i)	key assumptions and a list of policies relevant to apportioning costs, where costs are not fully recovered from a capital contribution;	2020 AMP Application SharePoint data room	Chapters 5, 6 Appendix G IPL758 AE-S010-Capital Contributions-v1.3	Sections 5.3.1 and 6.8 Sections G.4 and G.5	
88	D6(7)(c)(ii)	the rationale and basis for determining the forecast amount, including a description of any modelling used; and	2020 AMP Application	Chapters 5, 6 Appendix G	Sections 5.3.2 and 6.8.1, 6.8.2 Sections G.4 and G.5	
89	D6(7)(c)(iii)	provide this information separately for connection capex and for asset relocation capex.	2020 AMP Application	Chapters 5, 6 Appendix G	Sections 5.3 and 6.8 Sections G.4 and G.5	
90	D6(8)	In addition to the information required in clause 11.10 of Attachment A of the ID determination, for each system growth capex project and programme included in the capex forecast provide				
91	D6(8)(a)	a description of the project or programme, including the assumed number and ratings of significant new assets and, where appropriate, a single-line diagram showing how it is assumed that the assets will be integrated into the existing network;	2020 AMP	Chapter 6, Appendix F	Section 6.5	
92	D6(8)(b)	the estimated cost of the project or programme, disaggregated by disclosure year, including costs already incurred in the current period; and	SharePoint data room	S-17 Forecast Tracker - 12 June Submission.xlsx		
93	D6(8)(c)	details of the effect any new or emerging technologies may have and the extent that they have been considered.	2020 AMP	Chapter 6, Appendix F	Section 6.5	
94	D6(9)	In addition to the information required in clause 11.10 of Attachment A of the ID determination, for each reliability, safety and environment capex project and programme included in the capex forecast provide-				
95	D6(9)(a)	a description of the project or programme including the assumed number and ratings of significant new assets;	SharePoint data room	S-01 POD52 - RSE.pdf		There is no forecast RSE spend in the CPP period.
96	D6(9)(b)	a discussion of key assumptions and the rationale for making those assumptions;	SharePoint data room	S-01 POD52 - RSE.pdf		
97	D6(9)(c)	a description of models used and key input assumptions and data sources, including a discussion of relevant data systems and any limitations in the data;	SharePoint data room	S-01 POD52 - RSE.pdf		
98	D6(9)(d)	an indication of the project's or programme's current status in the planning process; and	SharePoint data room	S-01 POD52 - RSE.pdf		There is no forecast RSE spend in the CPP period.
99	D6(9)(e)	the estimated cost of the project or programme, disaggregated by disclosure year, including costs already incurred in the current period.	SharePoint data room	S-17 Forecast Tracker - 12 June Submission.xlsx		

100	D6(10)	In addition to the information required in clause 11.10 of Attachment A of the ID determination, for any consumer connection capex and asset relocation capex project and programme, provide a description and the estimated costs of any specific project or programme included in the forecast.	SharePoint data room	E-25 POD50 - Consumer Connection E-26 MOD50 - Consumer Connection Forecast Model V-112 P13 – Other Network Capex – Consumer Connection (presentation slide with Q&A) PR-5 MOD50 - Remarkables Upgrade Customised Estimate PR-7 Note regarding MOD50 – Consumer Connection Forecast Model PR-45 01 - Forecast Tracker - Post IV Review		
101	D6(11)	In addition to the information required by clause 11.12 of Attachment A of the ID determination, and, where not provided in response to subclause (2), identify the EDB's policies regarding the application of new or emerging technologies.	2020 AMP SharePoint data room	Chapter 6 IPL-1200 Aurora Energy Network Evolution Roadmap-r11.pdf	Section 6.6	Our network evolution plan aims to help prepare us for the wider adoption of distributed energy resources in the future
102	D7	**Lifecycle asset management planning (maintenance and renewal)**				
103	D7(1)	The description of Lifecycle Asset Management Planning required in clause 12 of Attachment A of the ID determination must include the additional information specified in this clause.				
104	D7(2)	In addition to information required by clauses 3.13 and 3.14 of Attachment A of the ID determination, describe the organisation that the EDB uses to manage network maintenance and associated expenditure, including the physical arrangements for undertaking these activities and the extent that these functions are centralised and outsourced.	2020 AMP Application	Chapter 4 Appendix M	Section 2.1.2, 4.8.2 Sections M.1, M.2	
105	D7(3)	In addition to the information required by clauses 12.1 and 12.2 of Attachment A of the ID determination, for each of service interruptions and emergencies opex, vegetation management opex and routine and corrective maintenance and inspection opex describe the approach used to prepare the expenditure forecast and provide-	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.2, H.4.2, H.5.2, H.6.2	

106	D7(3)(a)	details and a rationale for each relevant key assumption;	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive	Section H.3.2, H.4.2, H.5.2, H.6.2	
107	D7(3)(b)	a description of any models used;	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.2, H.4.2, H.5.2, H.6.2	
108	D7(3)(c)	a description of any new expenditure or forecast changes to the level of expenditure on existing network opex programmes over the course of the next period that will have a material effect on the network opex forecast, including-	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.3, H.4.3, H.5.3, H.6.3	

109	D7(3)(c)(i)	the rationale for and timing of these changes;	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.3, H.4.3, H.5.3, H.6.4	
110	D7(3)(c)(ii)	an assessment of the impact of these changes on the service levels provided by the EDB; and	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.3, H.4.3, H.5.3, H.6.5	
111	D7(3)(c)(iii)	the impact of these changes on the opex forecast.	Application SharePoint data room	Appendix H E-13 POD72 - Reactive Maintenance.pdf E-23 POD71 - Corrective Maintenance.pdf E-32 POD70 - Preventive Maintenance.pdf E-77 POD73 - Vegetation Management.pdf	Section H.3.3, H.4.3, H.5.3, H.6.5	

116	D7(6)	Identify all relevant documents, policies and consultants' reports that were taken into account in preparing the forecasts of asset replacement and renewal capex or asset replacement and renewal opex;	2020 AMP SharePoint data room	Chapters 5, 8 IP-1246 Aurora-Energy-2018-AMP-UPDATED for 2019.pdf V-40 RFI D293 - Aurora Pricebook Review Final 21 Jan 2020 IPC-980 AE-Policy-04 - Asset Management IPC-981 AE-Policy-01 - Health and Safety IP-12467 Aurora-Energy-2019-AMP-Update C-1326 191218 ISO 55001 summary IP2-97 01 - Pole Survivor Curve Model IPC-1075 AE-FA01-F01 - Compromised Pole Site Assessment IPC-1073 AE-FA01-F03 - Design - Structural Pole Assessment IPC-1039 AE-FR03-		Refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. We have provided examples of the relevant documents/policies/reports under the "document reference" column.
117	D7(7)	In addition to the information required by subclauses 12.3.3 – 12.3.5 of Attachment A of the ID determination, for each asset replacement and renewal capex or asset replacement and renewal opex project and programme provide-				
118	D7(7)(a)	a description of and the rationale for the projects and programmes;	2020 AMP Application	Chapter 8 Appendices E & H	Sections 8.1.3, 8.1.11, 8.2.3, 8.2.10, 8.2.17, 8.3.3, 8.3.11, 8.3.18, 8.4.2.1, 8.4.4.1, 8.4.5.1, 8.4.6.1, 8.4.7.1, 8.5.2.1, 8.5.3.1, 8.5.4.1, 8.5.5.1, 8.5.6.1, 8.5.7.1, 8.6.3, 8.6.11, 8.6.19, 8.6.27, 8.7.3, 8.7.10, 8.7.17, 8.7.24 Sections E.3.1, E.4.1, E.5.1, E.6.1, E.7.1, E.8.1, E.8.5, E.8.9, E.9.1, E.9.5, H.3.1, H.4.1, H.5.1, H.6.1	

119	D7(7)(b)	where relevant, an overview of any network and non-network alternatives considered and the basis for selecting the preferred solution;	2020 AMP	Chapter 8	Sections 8.1.8, 8.1.16, 8.2.8, 8.2.15, 8.2.22, 8.3.8, 8.3.16, 8.3.23, 8.4.3, 8.4.4.6, 8.4.6.6, 8.5.2.6, 8.5.3.6, 8.5.4.6, 8.5.5.6, 8.5.7.6, 8.6.8, 8.6.16, 8.6.24, 8.7.8, 8.7.15, 8.7.22	
120	D7(7)(c)	an indication of the project's or programme's current status in the planning process;	2020 AMP Application	Chapter 8 Appendices E & H	Sections 8.1.9, 8.1.17, 8.2.8.1, 8.2.15.1, 8.2.22.1, 8.3.9, 8.3.17, 8.3.24, 8.4.9, 8.5.2.7, 8.5.3.7, 8.5.4.7, 8.5.5.7, 8.5.6.7, 8.5.7.7, 8.6.9, 8.6.17, 8.6.25, 8.6.33, 8.7.8.1, 8.7.15.1, 8.7.22.1, 8.7.29.1 E.4.3, E.5.3, E.5.3, E.6.3, E.7.3, E.8.3, E.8.7, E.8.10, E.9.3, E.9.7, H.3.3, H.4.3, H.5.3, H.6.3	
121	D7(7)(d)	the actual and forecast expenditure on each project or programme described in subclause (a) disaggregated by regulatory year in both the current period and the next period; and	2020 AMP Application	Chapter 8 Appendices E & H	Sections 8.1.9, 8.1.17, 8.2.8.1, 8.2.15.1, 8.2.22.1, 8.3.9, 8.3.17, 8.3.24, 8.4.9, 8.5.2.7, 8.5.3.7, 8.5.4.7, 8.5.5.7, 8.5.6.7, 8.5.7.7, 8.6.9, 8.6.17, 8.6.25, 8.6.33, 8.7.8.1, 8.7.15.1, 8.7.22.1, 8.7.29.1 E.4.3, E.5.3, E.5.3, E.6.3, E.7.3, E.8.3, E.8.7, E.8.10, E.9.3, E.9.7, H.3.3, H.4.3, H.5.3, H.6.3	

122	D7(7)(e)	a description of the methodology used by the EDB to determine the forecast expenditure over the next period on the projects or programmes described in subclause (a) including where applicable-	2020 AMP Application	Chapter 8 Appendices E & H	Sections 8.1.9, 8.1.17, 8.2.8.1, 8.2.15.1, 8.2.22.1, 8.3.9, 8.3.17, 8.3.24, 8.4.9, 8.5.2.7, 8.5.3.7, 8.5.4.7, 8.5.5.7, 8.5.6.7, 8.5.7.7, 8.6.9, 8.6.17, 8.6.25, 8.6.33, 8.7.8.1, 8.7.15.1, 8.7.22.1, 8.7.29.1 E.3.2, E.4.2, E.5.2, E.6.2, E.7.2, E.8.2, E.8.6, E.8.11, E.9.2, E.9.6, H.3.2, H.4.2, H.5.2, H.6.2	
123	D7(7)(e)(i)	the key assumptions and the rationale for the key assumptions and policies;	2020 AMP Application	Chapter 8 Appendices E & H	Sections 8.1.9, 8.1.17, 8.2.8.1, 8.2.15.1, 8.2.22.1, 8.3.9, 8.3.17, 8.3.24, 8.4.9, 8.5.2.7, 8.5.3.7, 8.5.4.7, 8.5.5.7, 8.5.6.7, 8.5.7.7, 8.6.9, 8.6.17, 8.6.25, 8.6.33, 8.7.8.1, 8.7.15.1, 8.7.22.1, 8.7.29.1 E.3.2, E.4.2, E.5.2, E.6.2, E.7.2, E.8.2, E.8.6, E.8.11, E.9.2, E.9.6, H.3.2, H.4.2, H.5.2, H.6.2	
124	D7(7)(e)(ii)	any relevant modelling and the rationale for material model input assumptions; and	2020 AMP	Chapters 7, 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3.
125	D7(7)(e)(iii)	a commentary on the source of the unit costs or components of cost, the accuracy of the cost estimates and the treatment of cost uncertainty where there are not explicitly stated elsewhere.	2020 AMP	Chapters 7, 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3.
126	D7(8)	For an asset replacement and renewal capex project provide-	2020 AMP	Chapter 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3.
127	D7(8)(a)	assumed number and ratings of significant new assets; and	2020 AMP	Chapter 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. For example, refer to the following documents: E-20, E-40, E-41, E-42, E-43, E-44, E-45, E-46, E-47, E-48, E-49, E-50, E-51, E-52, E-9

128	D7(8)(b)	a single-line diagram showing how the project will be integrated into the existing network for projects involving a redesign of asset layout.	2020 AMP	Chapter 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. For example, refer to the following documents: E-20, E-40, E-41, E-42, E-43, E-44, E-45, E-46, E-47, E-48, E-49, E-50, E-51, E-52, E-9
129	D7(9)	Explain how any anticipated system growth associated with the replacement of assets before the end of their asset life has been taken into account in the asset replacement and renewal capex forecast for the next period.	2020 AMP	Chapters 5, 7, 8		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3.
130	D8	**Non-system fixed assets capital expenditure information**	N / A			Not applicable - the total non-network assets capex forecast is less than 5% of the total capex forecast
131	D8(1)	In addition to the information required by clause 13 of Attachment A of the ID determination, for non-network fixed assets capex in the capex forecast provide the rationale and the basis for determining the forecast amount, including a description of any modelling used for the expenditure in the largest two of the following expenditure categories by dollar value-	N / A			
132	D8(1)(a)	asset management systems;	N / A			
133	D8(1)(b)	information and technology systems;	N / A			
134	D8(1)(c)	motor vehicles;	N / A			
135	D8(1)(d)	office buildings, depots and workshops;	N / A			
136	D8(1)(e)	office furniture and equipment; and	N / A			
137	D8(1)(f)	tools, plant and machinery.	N / A			
138	D8(2)	The information required by subclause (1) need not be provided if the total nonnetwork assets capex forecast is less than 5% of the total capex forecast.	N / A			
139	D9	**Business support, system operations and network support operating expenditure**				
140	D9(1)	Provide sufficient details of the extent that business support and system operations and network support costs have been included in the capex forecast for each disclosure year of both the current period and next period.	SharePoint data room	V-119 RFI Nos D218 D236 and D468 - Capitalisation of Expenditure Standard.docx		
141	D9(2)	Identify all relevant documents, policies and consultants' reports that were taken into account in preparing these opex forecasts.	Application	Appendix I		In addition, refer to the documents provided to the Verifier. All documents provided to the Verifier are in the SharePoint data room and documented in the Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3.
142	D9(3)	Describe any anticipated material changes to the information provided in subclause (1) over the course of the next period and discuss-	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		
143	D9(3)(a)	the rationale for and timing of the changes; and	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		
144	D9(3)(b)	the impact of the changes on the opex forecast.	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		
145	D9(4)	Describe the approach used to prepare the relevant opex forecast including-	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		

146	D9(4)(a)	each relevant key assumption including the rationale for the assumption;	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		
147	D9(4)(b)	any models used; and	SharePoint data room	E82 MOD80 - SONS Forecast Model.xlsx E81 MOD81 - People Cost Forecast Model.xlsx		
148	D9(4)(c)	the rationale for any new expenditure or step change from current levels of expenditure over the next period.	SharePoint data room	E35 POD80 - SONS.pdf E36 - POD81 - PEOPLE.pdf		
149	D9(5)	Where appropriate, the information required by this clause should be provided separately for business support opex and for system operations and network support opex.				Business support opex portfolios are separate to our SONS opex portfolio
150	D10	**Identified programmes**				
151	D10(1)	Where not already required to be disclosed by Attachment A of the ID determination, for each identified programme provide-	SharePoint data room	E-11 POD31 - Arrowtown 33kV Ring Upgrade.pdf PR-34 POD31 - Arrowtown 33kV Ring Upgrade - Post IV Review.doc E-13 POD72 - Reactive Maintenance.pdf E-16 POD02 - Crossarms.pdf E-17 POD04 - Distribution Conductor.pdf E-19 POD24 - Protection.pdf E-22 POD34 - Riverbank Zone Substation Upgrade.pdf E-23 POD71 - Corrective Maintenance.pdf E-25 POD50 - Consumer Connection.pdf E-28 POD01 - Poles.pdf		All documents provided to the Verifier are in the SharePoint site and documented in the Independent Verifier Report in Appendix I, specifically Table I.1, Table I.2 and Table I.3. Chapter 2.3 describes the process of document and information submission Appendix C lists the identified programmes and the relevant documents for each selected programme.
152	D10(1)(a)	a description of the project or programme including-	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
153	D10(1)(a)(i)	what the project or programme will accomplish;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		

154	D10(1)(a)(ii)	the location of the project or, if relevant, the location of the programme;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
155	D10(1)(a)(iii)	assumed quantities and ratings of major assets, including the rationale for these assumptions;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
156	D10(1)(a)(iv)	where relevant, a high-level single-line diagram showing the assumed layout of the project and interfaces with the existing network; and	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
157	D10(1)(a)(v)	any other information consistent with the nature of the project or programme that is necessary to fully describe the scope of the project and what is involved in its implementation;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
158	D10(1)(b)	a description of the rationale for the project or programme including-	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
159	D10(1)(b)(i)	the extent that the project or programme meets the expenditure objective; and	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
160	D10(1)(b)(ii)	the impact of not progressing within the CPP regulatory period;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
161	D10(1)(c)	a statement as to the project's or programme's current status in the planning process;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
162	D10(1)(d)	an overview of potential alternatives, including non-network alternatives, and the basis for selecting the preferred option with the information provided to be commensurate with the project's or programme's current status in the planning process;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
163	D10(1)(e)	the rationale for the proposed timing of the project or, where relevant, the rational for the proposed timing of the programme;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
164	D10(1)(f)	where applicable, an assessment of the impact of the project or programme on the service levels provided by the EDB;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
165	D10(1)(g)	if a programme is a continuation or extension of an existing programme, the rationale for any material changes in the forecast expenditure from the level of expenditure on the programme during the current period;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
166	D10(1)(h)	a detailed breakdown of the estimate of the project or programme costs, disaggregated by disclosure year, including a similar breakdown of any project or programme costs incurred during the current period;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
167	D10(1)(i)	in addition to the breakdown provided in response to subclause (f)-	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
168	D10(1)(i)(i)	a description of the methodology used to prepare the estimate;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
169	D10(1)(i)(ii)	where applicable, the quantities provided for in the project or programme cost; and	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
170	D10(1)(i)(iii)	identification of scope or cost uncertainties and an explanation of how such uncertainties have been taken into account in the estimate;	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		

171	D10(1)(j)	details of how the EDB proposes to measure and manage the efficiency of the implementation of the project or programme; and	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
172	D10(1)(k)	a description of any cost benefit analyses relevant to the project or programme undertaken by or for the EDB.	SharePoint data room	Refer to documents referenced in relation to clause D10(1) above		
173	D11	**Risk management**				
174	D11(1)	In addition to the information required by clause 14.3 of Attachment A of the ID determination, for any proposed self-insurance allowance-	Application	Appendix V		Not applicable - no self-insurance allowance is proposed
175	D11(1)(a)	provide-	N / A			
176	D11(1)(a)(i)	a description of the uncertainties covered by the allowance;	N / A			
177	D11(1)(a)(ii)	the methodology used to calculate the self-insurance risk premium	N / A			
178		(e.g. probability multiplied by consequence);	N / A			
179	D11(1)(a)(iii)	a report on the calculation of each self-insurance risk premium from	N / A			
180		an actuary who is qualified to provide such advice; and	N / A			
181	D11(1)(a)(iv)	any quotes obtained from external insurers; and	N / A			
182	D11(1)(b)	explain why compensation should be provided for the uncertainty.	N / A			
183	D11(2)	In respect of each quote provided in accordance with subclause (1)(a)(iv)-	N / A			
184	D11(2)(a)	state-	N / A			
185	D11(2)(a)(i)	the amount insured for which the quote related (if not included in the quote itself);	N / A			
186	D11(2)(a)(ii)	the annual premium payable or paid by the EDB;	N / A			
187	D11(2)(a)(iii)	the size of any deductible;	N / A			
188	D11(2)(a)(iv)	the terms and conditions of the insurance; and	N / A			
189	D11(2)(a)(v)	why it is not considered suitable.	N / A			
190	D11(3)	Explain whether and, if so, how the costs of remediating the effects of each uncertainty for which the allowance is sought may be recovered through any other mechanism.	N / A			
191	D12	**Related Parties**				
192	D12(1)	Identify and describe all related parties in respect of whom costs are disclosed for the last disclosure year of the current period, and relationships with those related parties.	Financial/Model report	Appendix B		Note that a modification has been sought for the definition of "current period" to mean the 5 disclosure years from 1 April 2014 to 31 March 2019. Accordingly, the relevant information has been provided for RY19 (the last disclosure year of the current period).
193	D12(2)	Describe, at an aggregate level, the-				
194	D12(2)(a)	nature of the services undertaken by all related parties in the last year of the current period; and	Financial/Model report	Appendix B	Table B.1	
195	D12(2)(b)	processes for procuring services undertaken by related parties, or by anticipated related parties, during the last year of the current period and the assessment period.	Financial/Model report	Appendix B	Table B.1	
196	D12(3)	For services identified in subclause (2), describe-				
197	D12(3)(a)	whether similar services are expected to be provided by related parties, or by anticipated related parties, during the next period;	Financial/Model report	Appendix B	Table B.1	
198	D12(3)(b)	whether any additional services are expected to be provided by related parties, or by anticipated related parties, during the CPP regulatory period; and	Financial/Model report	Appendix B	Table B.1	
199	D12(3)(c)	the basis for establishing the related party transaction values for the purpose of the capex forecast and the opex forecast.	Financial/Model report	Chapters 6, 7, Appendix B	Sections 6.4 and 7.7	
200	D12(4)	Describe the nature of the contract for any periodic services, including the duration of any such contract.	Financial/Model report	Chapter 6, Appendix B	Section 6.4	The only relevant contract with a related party is the Field Services Agreement with Delta. That agreement has an initial term of three years.
201	D12(5)	For each service identified in accordance with subclause (2), provide an example of-				
202	D12(5)(a)	any tendering process used to procure the service;	Financial/Model report	Appendix B		

203	D12(5)(b)	relevant documents used to tender for the provision of the service, including, but not limited to, requests for tender, and tender submissions;	Financial/Model report SharePoint data room	Appendix B S-20 ARR Tender Example.pdf S-21 System Growth Tender Example.pdf		Aurora has legal advice that it is unable to disclose the tender submissions without the consent of the tendering parties. However, we have provided documents that summarise and evaluate the submissions and contain all the relevant information anticipated by this clause. This information is provided at the end of the tender example documents.
204	D12(5)(c)	explain-				
205	D12(5)(c)(i)	whether the service procured are provided under a discrete contract or provided as part of a broader operational contract (or similar); and	Financial/Model report	Appendix B		As above, the only relevant contract with a related party is the Field Services Agreement with Delta.
206	D12(5)(c)(ii)	whether the service was procured on a genuinely competitive basis and if not, why not; and	Financial/Model report	Chapters 6 & 7, Appendix B	Sections 6.4, 7.7	
207	D12(5)(d)	methodologies, consultants' reports, or key assumptions used to determine components of the costs included in the contract price.	Financial/Model report SharePoint data room	Appendix B S-18 SONS - example consultants report.pdf S-19 Systems growth - example consultants report.pdf		
208	D13	**Deliverability**				
209	D13(1)	In addition to clauses 14 and 16 of Attachment A of the ID determination provide an overview of, and description of outputs from, any deliverability risk assessment that the EDB has completed for part or all of the capex forecast and the opex forecast.	SharePoint data room	E-58 - Efficient Delivery of our CPP Work Programme - Explanatory Memo.pdf E-84 Technology and Digital Transformation Governance Group TOR.docx E-88 Quality Management Approach Template.docx E-90 Risk Management Approach Template.docx E-91 Project Close Report Template.docx E-93 Project Plan Template.docx E-95 Project Brief Template.docx E-96 Stage Plan Template.docx E-97 Project Initiation Template.docx IP-1239 AE-DF03-F02		
210	D13(2)	Where it has not been provided in risk assessment information under subclause (1), provide an overview of the EDB plans to ensure the deliverability of the activities provided for in the capex forecast and the opex forecast, with particular reference to-	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		

211	D13(2)(a)	a description of the prioritisation or other methodologies used to optimise delivery;	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
212	D13(2)(b)	how consenting processes are managed to optimise delivery;	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
213	D13(2)(c)	the extent that the activities provided for in the capex forecast and the opex forecast will be undertaken internally or outsourced;	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
214	D13(2)(d)	the EDB's ability to implement any planned step change from historical levels of expenditure and workload, including-	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
215	D13(2)(d)(i)	the ability of contractors available to the EDB to deliver any proposed increase in workload;	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
216	D13(2)(d)(ii)	the current level of skilled personnel, including engineering and project management personnel, available to the EDB compared to the anticipated requirement over the next period; and	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
217	D13(2)(d)(iii)	the measures the EDB plans to take to source and secure required additional personnel; and	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
218	D13(2)(e)	how the EDB aligns resource schedules where shared resources are used for different opex-related and capex-related tasks.	SharePoint data room	Refer to documents referenced in relation to clause D13(1) above		
219	D14	**Unit costs and expenditure escalators**				
220	D14(1)	Explain the methodologies applied to convert constant price capex forecast and opex forecast to the nominal price capex forecast and opex forecast.	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
221	D14(2)	Explain why the methodologies applied, each key assumption, and the resulting quantum are reasonable.	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
222	D14(3)	For each key assumption, including unit rates, indexes, weightings, and contingency factors-	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
223	D14(3)(a)	identify-	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
224	D14(3)(a)(i)	the key assumption;	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
225	D14(3)(a)(ii)	source material from which it was derived; and	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
226	D14(3)(a)(iii)	the components of expenditure to which it applies; and	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
227	D14(3)(b)	explain-	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
228	D14(3)(b)(i)	how it has been applied in the capex forecast and opex forecast;	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
229	D14(3)(b)(ii)	the quantum of costs in the capex forecast and opex forecast resulting from the application of the key assumption; and	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
230	D14(3)(b)(iii)	whether, and if so, how the key assumption relates to capex and opex incurred during the current period.	Financial/Model report	Chapters 6, 7	Sections 6.3 and 7.3.4	
231	D15	**Contingent project information**				
232	D15(1)	For each proposed contingent project-	Application	Appendix V		Not applicable - no contingent projects are proposed
233	D15(1)(a)	provide-	N / A			
234	D15(1)(a)(i)	an overall description including the aims and objectives of the project;	N / A			

235	D15(1)(a)(ii)	completed regulatory templates for capex and opex forecasts using the best available information to hand; and	N / A			
236	D15(1)(a)(iii)	information as to how the project satisfies the criteria specified in clause 5.6.5(2);	N / A			
237	D15(1)(b)	propose a trigger event and explain how the event meets the requirements of clause 5.6.5(3);	N / A			
238	D15(1)(c)	provide-	N / A			
239	D15(1)(c)(i)	all relevant documents (including policies and consultants' reports) that were taken into account in preparing the capex forecast and opex forecast for the contingent project, including those that relate to its deliverability;	N / A			
240	D15(1)(c)(ii)	each relevant key assumption; and	N / A			
241	D15(1)(c)(iii)	each relevant obligation;	N / A			
242	D15(1)(d)	explain-	N / A			
243	D15(1)(d)(i)	all departures from any conclusions and recommendations contained in each consultant's report identified in accordance with subclause (c)(i); and	N / A			
244	D15(1)(d)(ii)	the methodology used to generate the capex and opex forecast for the proposed contingent project;	N / A			
245	D15(1)(e)	explain for each policy identified in response to subclause (c)(i)-	N / A			
246	D15(1)(e)(i)	how it was taken into account and complied with; and	N / A			
247	D15(1)(e)(ii)	how the relevant planning standards were incorporated; and	N / A			
248	D15(1)(f)	describe for each key assumption identified in accordance with subclause (c)(ii)-	N / A			
249	D15(1)(f)(i)	the method and information used to develop the assumption; and	N / A			
250	D15(1)(f)(ii)	how it has been applied and its effect on the capex and opex.	N / A			
251	D15(2)	Where any proposed contingent project is likely to terminate after the end of the next period, in addition to the information required by subclause (1), provide any additional information relevant to forecast capex and forecast opex to the end of the contingent project.	N / A			

Appendix V. IM Requirements Not Applicable

994. Table 62, below, details the IM requirements that do not apply to Aurora Energy's CPP Application.

Table 62: IM requirements that do not apply to Aurora Energy's CPP Application

Relevant clause	Non-applicable requirement
5.1.4(1)(d)(i), 5.1.4(1)(d)(ii)	The Independent Auditor's report notes that the Independent Auditor obtained all information and explanations that the Independent Auditor required to provide a basis for their opinion
5.1.4(2)	The Independent Auditor's report has been written to meet the requirement of clause 5.5.3 only. Accordingly, clause 5.1.4(2) does not apply
5.3.5(2)	There are no forecast asset sales that meet the definition of clause 5.3.5(2)
5.3.6(2)	There are no shared asset acquisitions during the forecast period
5.3.6(4)	There are no forecast asset sales that meet the definition of clause 5.3.6(4)
5.3.8, 5.4.12(3)	Alternative depreciation not applied
5.3.11(1)(e), 5.4.14(1)(d)(i)	Our expenditure forecasts do not include any forecast acquisitions from other regulated entities that have been used by that regulated supplier in the supply of regulated goods or services
5.3.11(1)(f), 5.4.14(1)(d)(ii)	We do not provide any other regulated services
5.3.11(1)(i)	Our forecast does not include any value for vested assets that exceeds the amount of consideration provided or forecast to be provided
5.3.11(1)(k)	We have not forecast any innovation project allowance
5.3.11(2)	All assets forecast to be commissioned are directly attributable
5.3.11(4)(d) – (h)	No expenditure on capital contributions is forecast to incur financing costs
5.3.11(4)(i), 5.3.11(5)(a)	No income is forecast from assets while they are in works under construction
5.3.11(8)	Arm's length value for related party transactions has already been supported on the basis that forecasts are either determined using a base-step-trend forecast approach or apply independently determined unit rates that represent market values
5.3.14, 5.4.20	There are no opening or current period tax losses and we have not forecast any tax loses during the forecast period
5.3.19(3)	No assets are forecast to be acquired from another regulated supplier
5.3.23, 5.3.24, 5.3.25, 5.4.27(3)	No TCSD allowance is forecast

Relevant clause	Non-applicable requirement
5.3.26, 5.4.33	We do not propose any AMWEEs in our CPP proposal
5.4.1(2)	The CPP is not made pursuant to a catastrophic event
5.4.9(2)(v), 5.4.9(5)	Proxy allocators are not applied
5.4.9(3)	There are no forecast asset sales that meet the definition of clause 5.3.5(2) or 5.3.6(4), therefore clause 5.4.9(3) does not apply
5.4.9(7)	There are no forecast asset sales the meet the definition of 5.3.6(4), therefore clause 5.4.9(7) does not apply
5.4.10(1)	No arms-length deduction applied
5.4.10(2) and (3)	No OVABAA applied
5.4.12(4)	Aurora's CPP does not propose a different physical asset life to the standard physical asset life for any assets
5.4.14(1)(e)	Our forecast value of commissioned assets does not include any network spares
5.4.14(4)	We do not provide any other regulated services and our expenditure forecasts do not include any forecast acquisitions from other regulated entities that have been used by that regulated supplier in the supply of regulated goods or services
5.4.15(1) and (2)	No assets are forecast to be sold to a related party or transferred to another part of Aurora
5.4.19(3)	Aurora is not forecasting any discretionary discounts or customer rebates
5.4.26(5)	Regulatory tax asset values have been calculated in accordance with the modification to 5.4.26(3)
5.4.31	No new pass-through costs are proposed
5.5.1(2)	Hard copy reference material was irrelevant as all material was available electronically and we used a range of engagement channels to communicate with customers. Regardless, hard copies of the consultation document were also readily available at 12 locations and mailed on request
5.5.4(5)	This clause applies post-submission
5.5.4(6)	This clause applies post-submission
D2(3)	No information required in Schedule D has been omitted from Aurora's CPP proposal
D6(6)(a)(i)	Aurora does not conduct sensitivity analysis for forecasts of consumer connections, embedded generation and electricity volumes
D6(6)(a)(ii)	Aurora does not conduct weather normalisation / impact analysis for forecasts of consumer connections, embedded generation and electricity volumes

Relevant clause	Non-applicable requirement
D8	The total non-network assets capex forecast is less than 5% of the total capex forecast
D11	No self-insurance allowances currently or proposed
D15	No contingent projects proposed

Appendix W. Funding Assurance

995. The following letter confirms funding availability for our CPP proposal.

Dunedin City Treasury Ltd

50 The Octagon
PO Box 5045
Dunedin 9058
New Zealand
Telephone (03) 474 3696
Email dunedincitytreasury@dcc.govt.nz

28 May 2020

The Chair
Aurora Energy Limited
10 Halsey Street
Dunedin 9016

Dear Steve,

Letter of Comfort

The purpose of this letter is to give you comfort that Dunedin City Treasury Ltd (DCTL) is aware of Aurora Energy's impending Customised Price-Quality Path (CPP) application and the significant expenditure commitment associated with your 3-year CPP investment plan.

DCTL is supportive of Aurora Energy's CPP application.

We acknowledge that as the entity charged with funding both Dunedin City Council and the wider Dunedin City Holdings Ltd group, we are in receipt of Aurora Energy's term debt forecasts and will work to ensure that credit lines are in place to accommodate the company's funding requirements throughout the CPP period.

Yours faithfully

Chair
DUNEDIN CITY TREASURY LIMITED

Aurora
ENERGY