ASSET MANAGEMENT PLAN

APRIL 2018 – MARCH 2028

19 October 2018

Aurora
ENERGY

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PREFACE

This is the Aurora Energy Asset Management Plan (AMP) for 2018, our first as a standalone network owner.

This transitional AMP has changed significantly from previous versions reflecting the views of our new Board and asset management team. We hope the changes improve your experience and make it a more valuable resource for you. We will further develop its content for our 2019 AMP based on your feedback.

Since our separation from Delta last year we are a new team at Aurora Energy, with a focus on driving improvements and lifting customer service. We have had two main priorities since then: ensure our networks are safe and build the capability to deliver what is our largest ever work programme.

Low levels of historical investment mean that a proportion of our assets are now in poor condition and need to be renewed. We take our responsibility to provide a safe, reliable electricity supply to our customers and the community very seriously. We agree that it would be unacceptable if our assets were to fail in service due to their condition or a lack of maintenance. We are focussing on returning our asset fleets to a satisfactory condition but recognise that this will take both time and significant investment.

Last year we committed to higher levels of investment to upgrade our ageing networks and to cater for future growth. Those plans have turned into action and this year saw record expenditure on replacing, upgrading and maintaining our assets.

Last year we took urgent steps to address the pressing issue of some of our worst condition poles through our fast track pole programme which concluded in December. That was a start, but with the age and state of the network, we still have a lot of work ahead to inspect, maintain and upgrade other equipment, as well as continuing to return our poles fleet to a satisfactory state of health.

We commissioned an independent review to provide a baseline assessment of the state of our network. Based on its interim findings we expect it to confirm what we have identified as priority areas for investment. The review, once finalised, together with stakeholder feedback will be a key input into our future network investment plans.

We will submit a CPP application to the Commerce Commission in May 2020 and transition to this mechanism from April 2021. As part of that process, we will undertake a series of detailed consultations with customers on our proposed investment plans and what these will mean for future network charges and reliability. This AMP provides a starting point for our programme of stakeholder engagement and CPP consultation over the next 18 months.

We know that as a new organisation we need to gain the confidence and trust of our stakeholders. We have a lot to improve on in the next ten years and are committed to making the needed investments. Safety will continue to be our number one priority when identifying and prioritising those investments.

From me and the team, thanks for taking the time to read our AMP.

Richard Fletcher
CHIEF EXECUTIVE

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EXECUTIVE SUMMARY

This Asset Management Plan (AMP) outlines Aurora Energy's intended approach to managing its electricity distribution assets during the period 1 April 2018 to 31 March 2028.

Our 2018 Asset Management Plan

Our AMP sets out the investments we plan to make over the next ten years to provide safe and reliable power supply to electricity consumers in Dunedin and Central Otago.

We are publishing this AMP during October following a Commerce Commission extension of the usual publication deadline.[1] The extension provided additional time to prepare an AMP that better reflects our business following our separation from Delta Utility Services (Delta) in July 2017. It has allowed us to include recent structural and asset management changes and changes to our major works programmes, and provide updates based on findings from external reviews that have been progressing since we became a standalone business. The latter includes an independent review of the state of our networks. The extension has also enabled us to take a full year of post-separation operational expenditure into account when developing our forecasts.

Reflecting the transitional nature of our first AMP (post-separation), we have redesigned and refocused it to reflect our status as a new standalone business. This includes refining our asset management objectives, simplifying asset-related discussions, and making the document more accessible for stakeholders. Over the coming months, we plan to further develop our AMP to support increased customer engagement as we prepare for a customised price-quality path (CPP) proposal.

What is a customised price-quality path (CPP)?

A CPP is a regulatory mechanism that a regulated business can use if it believes its current price-quality path does not meet its needs, particularly its future investment needs.

Following consultation with stakeholders a business submits a CPP proposal to the Commission, who will complete a detailed assessment of it before determining what price path and quality standards should apply.

Over the coming months, our AMP forecasts will be refined. They will encompass a five-year CPP period, during which our investments will be subject to extensive consultation and scrutiny by the Commission. These longer term investment plans will reflect the feedback we receive from customers, as we are aware that decisions we make on network expenditure ultimately flow through to the prices they pay.

We hope the changes to our AMP will make it easier for customers and stakeholders to connect with us as we strengthen our new business. We want our customers to tell us what they value from their electricity network and how they think we're performing. A good way to do this is by sending an email to: info@auroraenergy.co.nz.

[1] We requested that the Commerce Commission grant an extension to the deadline for the publication of our 2018 AMP to 31 August 2018. This was subsequently extended to October so that we could take the interim findings of an independent state of the network review (Independent Review) into account.

Our AMP forecasts maintain elevated levels of investment

As signalled in our 2017 AMP, we need to increase the level of investment in our network. With low levels of historical investment, our assets have deteriorated over time. Our analysis indicates a need to lift maintenance and renewal expenditure in targeted areas across our network. Over the last two years we have significantly increased our renewal and maintenance activity, but more needs to be done.

Historically, some parts of the network were not adequately maintained. It is essential that we address that now.

This is necessary if we are to stabilise network performance and deliver a valued service to customers. To achieve this, we need to make sure our network assets are fit for purpose and can continue to deliver a reliable and secure service. We are focussing on investment to replace assets that are no longer meeting their required safety and reliability performance levels. Since our 2017 AMP, our forecasts have been further refined, in terms of priority and timing, based on subsequent improvements in asset knowledge and updated risk assessments.

Similar to the AMPs of other electricity distribution businesses, the accuracy and granularity of our forecasts will vary over the 10-year AMP period. The final independent review report is likely to result in some changes to our short term plans but in general, the initial three years (RY19[2] to RY21) are more certain and are supported by detailed plans focussed on addressing a backlog of poor condition assets.

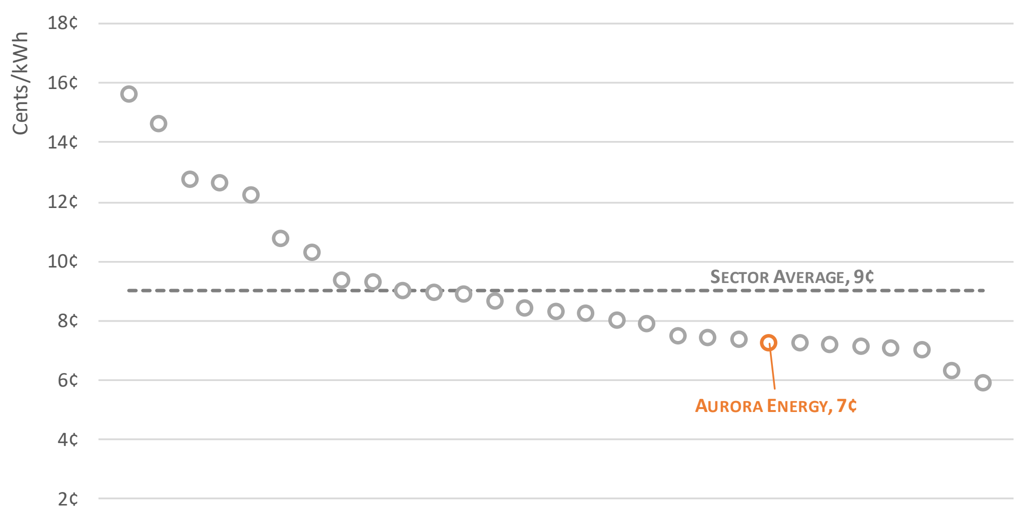
Network Investment

We plan to sustain increased levels of network investment over the next decade, spending $748 million on new developments and renewing and maintaining the existing network.

These investments will lead to an increase in prices

In New Zealand, the cost of building and maintaining electricity distribution and transmission supply infrastructure is recovered through the line charge component of consumers' electricity bills. Aurora Energy customers currently pay some of the lowest line charges in the country, as shown below.

Revenue benchmarking (cents per kilowatt hour)[3]



[2] RY19 denotes the 2019 regulatory year, being the 12 month period 1 April 2018 to 31 March 2019.

[3] Total line charge revenue including distribution and transmission, Electricity Distribution Business Information Disclosures 2017.

Delivering a safe and reliable service into the future requires that we invest more in the network. Ultimately those costs are passed on to customers through increased line charges on their power bills. Price increases arising from our CPP must first have the approval of the sector regulator, the Commerce Commission and will be subject to extensive consultation with customers and other stakeholders.[4]

We are transitioning to a new standalone business

Historically, Delta undertook both asset management and service provider roles on behalf of Aurora Energy, the asset owner. Following an independent review in early 2017 our shareholder – Dunedin City Holdings – sought formal separation of the two businesses. From 1 July 2017, Aurora Energy became a standalone regulated asset owner and manager, with accountability for providing electricity distribution services.

This decision saw an initial 100 staff transfer to Aurora Energy to independently carry out asset management, engineering design and corporate and customer services. Under the new arrangement, Delta is an arms-length service provider subject to full commercial terms. Since the separation, we have been transitioning to a new way of doing business. This involves a significant level of change for our people and the way we operate. We are continuing to improve and transform our business to focus on this new role.

While we are making good progress, it is essential that we maintain, and in some areas accelerate, the pace of change.

We expect customers to benefit from these changes

The separation ensures that dedicated, focused governance and leadership is applied to the long-term management of our electricity assets, without the wider focus that was previously required when also managing a contracting business. Our new business has clearer accountabilities to customers, including that we seek the best available services from the market. It requires increased transparency and commercial tension in our procurement processes. These benefits will, over time, reduce the underlying cost of delivering a safe and reliable service to customers.

There have been further changes since our previous AMP

Since publishing our 2017 AMP, as well as continuing the delivery of our larger work programme, we have overseen a number of further changes across our business:

- increased our focus on stakeholder engagement
- introduced contestable service delivery arrangements
- improved our processes to support customer services
- completed an accelerated pole renewal programme
- commissioned an independent review of our network assets
- begun an internal asset management improvement programme
- overseen a number of senior management team changes.

Below we explain the implications of these changes.

[4] The Commerce Commission sets maximum revenues that an EDB can recover. This determines the level of allowed price increase.

Increased levels of stakeholder engagement

We know that as a new organisation we need to rebuild confidence and improve our customer responsiveness. To support this we are planning a major programme of stakeholder engagement and consultation over the next 12 months.

This year we have published the first in a series of community updates which will let stakeholders know what we have achieved and explain our future investment plans. Over time, we will also produce a series of more substantive updates on our network and associated performance. These regular, open engagements will help stakeholders provide input into our future plans and performance objectives. Over the coming months we will publish details of these consultations on our website.

In August 2018, we set up a series of ongoing Customer Voice Panels across each of our service regions to hear from customers directly on what we are doing and to better understand their needs and preferences as we look towards the future. The panels bring together a cross-section of residential and business customers and we look forward to continued engagement with them.

Over the next six months we will also begin engaging with customers on the results of the Independent Review as well as on a variety of other subjects. We will use the outcomes of these various engagements to inform the development of our CPP proposal.

This AMP is a further opportunity for stakeholders to let us know how we're doing. We welcome feedback on the plans set out in this AMP or any concerns that our stakeholders may have.

Introducing contestability

In August 2018, we appointed two additional service providers to carry out renewal, maintenance and development work: Unison Contracting based in Dunedin, and Connetics based in Central Otago. The increased use of competitive tendering and the introduction of additional service providers will lower the risk of under-delivery and help ensure we receive efficient and market-tested pricing.

To ensure a controlled switchover to new suppliers, and to allow Delta's new operating arrangements to bed in, we will transition to the new arrangements from 1 April 2019 and will gradually increase the level of contestability.

Customer experience and customer choice

We are actively working to improve customer experience and provide better service to customers seeking new connections to our network. In early 2019, we will be introducing a new model to provide greater choice in how we provide customer connections and customer-initiated work.

A recent organisational restructure has established clearer accountability for customer engagement, with a new General Manager Customer and Engagement role created, for which we are currently recruiting. The transition to the new structure and improvements to our customer processes will take time, but we expect that by next year we will have made visible progress and achieved demonstrable improvements in customer satisfaction. We will also work to further improve outage communications.

Fast Track Pole Programme

In November 2016, we instigated the Fast Track Pole Programme. The trigger for this initiative was the need to address a backlog of poor condition poles and to mobilise a company-wide effort to ensure at-risk poles were removed from the network. This programme instigated a number of process improvements that have been embedded under our new operating model.

The fast track programme has now been completed, significantly reducing the backlog of at-risk poles and reducing overall risk on the network. The programme remediated approximately 3,000 wooden poles out of a then total of over 31,000 wooden poles on the network.

We have a number of legacy poles still in need of priority replacement or reinforcement[5] and our ongoing pole renewal programme will continue to focus on the backlog. We anticipate that another three years of pole replacement and strengthening at an elevated level is required before renewals expenditure reduces to a sustainable, steady-state level.

Independent Review

In March 2018, in conjunction with the Commerce Commission, we initiated an independent review of the state of our electricity network. The key aims of the independent review are to confirm the state of our network and to determine the resulting risk to customers and the wider public.

WSP[6] provided interim findings from their ongoing assessment to ourselves and the Commerce Commission at the end of August 2018. This included its emerging views on a number of assets fleets.[7] We have reflected these views by updating our AMP investment plans[8], for example we have:

- increased the volume of crossarms to be replaced during the planning period
- sought improved protection system performance through increased battery system upgrades and replacements in addition to the replacement of nearly all electromechanical and static relays over the ten year period
- reprioritised our zone substation switchgear replacement programme.

In carrying out its review, WSP brought the latest techniques in asset inspections and a robust framework for systematically assessing risk and criticality in asset renewal decisions. We will gain enduring benefit from this expertise as we adopt new inspections methods and refine our risk management framework.

The emerging view of the Independent Review supports our planned investment in critical areas with some refinements to condition and risk assessment, outlined in the table below.

5 1,027 red-tagged poles as at October 2018.

6 The independent reviewer is WSP, one of the world's leading engineering consulting firms, operating as WSP Opus in New Zealand.

7 While we anticipate that the final WSP report will include more detail and the conclusions may vary slightly, we do not expect WSPs overall conclusions to change materially.

8 The changes refer to our initial 2018 AMP forecasts, and not those published in previous versions of our AMPs.

Changes to planned investment resulting from independent review interim feedback

WSP emerging view	How we responded in 2018 AMP	Expenditure
Poles. Using survivor curve analysis, WSP suggest circa 2,500 poles will reach end-of-life during the next 12 months. Safety risk is linked to population density.	Our pole programme is prioritised according to areas of high population density (safety criticality). We plan to continue elevated levels of pole remediation in the first three years of the AMP period to address a backlog of end-of-life poles. Our forecast also includes the replacement of poles where it is impractical or uneconomic to repair defects, such as split pole tops.	→
Crossarms. A large proportion of the crossarm fleet exceeds expected lifespan.	We agree with WSP's view. We have developed plans to improve and expand condition assessments of pole tops and crossarms, and have increased our planned 10-year renewals expenditure on crossarms.	↑
Overhead lines. Based on drone inspection sampling, WSP suggests that visual evidence indicates only a modest level of conductor deterioration. Forensic testing would help better understand conductor strength and deterioration.	We revised our asset health assessment for overhead lines consistent with industry expected lifespans in similar environments. We have retained a significant level of investment in planned conductor replacement ($55 m over ten years) to ensure we can address all current and emerging risks. We will continue to improve our conductor condition data through more inspection and testing.	→
Underground cables. A small proportion of PILC type cables exceed expected lifespan, but these present a low risk to reliability and public safety.	We agree with WSP's findings and have reduced the expected lifespan for PILC (paper insulated, lead covered) type cables. We plan to carry out PILC cable replacement in the medium to long term, as the risk associated with a failure is low in the short term.	↑
Zone substation switchgear. Emerging view that zone substation switchgear is a high risk.	We agree with WSP's findings. Our current plan covers replacement of switchgear that we (and WSP) identified as high risk. Pending the conclusions in the final WSP report and investigations of our own, we anticipate further refinement and perhaps an uplift in our zone substation switchgear forecast. Consideration will need to be given to whether service providers will be able to deliver uplifts in work volumes.	→
Protection relays. Performance in clearing faults is poor in some situations. A large proportion of electromechanical relays exceed expected lifespan.	We agree with WSP's findings. The current forecast allows for replacement of most, if not all, of the static and electromechanical relays in the ten year period. We have increased the allowance for battery system replacement and upgrading for redundancy to improve protection operation performance.	↑

We expect the final WSP report to be completed later this month. We will consider its findings in detail as we prepare our March 2019 AMP. In the interim we will adjust our investment plans if any significant additional risks are raised in the report.

Asset Management Development Plan

Building on our most recent self-assessment of asset management maturity (AMMAT), and inputs from stakeholders, we have begun a process to improve our asset management processes and capabilities. We recognise that there are a number of areas where we can improve our performance.

To lay the foundations for improving our overall performance, we have critical business improvement initiatives planned or already underway. The objective of these improvement initiatives is to ensure we can provide customers with a safe and reliable electricity distribution service, while minimising the whole-of-life cost of managing our assets. We have identified a number of improvement areas including: engineering competency, delivery capability, risk management, and network planning.

Our ultimate aim is to ensure our asset management is consistent with leading New Zealand practice within a five-year period. We plan to use asset management certification (ISO 55000[9]) to monitor and demonstrate our progress to stakeholders.

Asset management certification

We will achieve leading practice asset management capability within five years (supported by seeking ISO 55000 certification). We recognise that this is an ambitious undertaking given our starting point, but we are committed to making real progress in this critical area.

We have made changes to our management team

Effective leadership is important in any business experiencing significant change. We have made significant changes to our management team since publishing AMP 2017. Richard Fletcher, previously General Manager Commercial and Regulatory Affairs at Powerco, was appointed as our CEO in January 2018. Glenn Coates was appointed as our new General Manager Asset Management and Planning in March 2018. Previously with Orion, he brings close to 30 years of experience in the electricity industry including strengths in asset management strategy, network planning, demand side management and future networks.

These two appointments see experienced executives from large EDBs joining our leadership team to help lead our management thinking. Both have been closely involved in CPP submissions driven by a need for increased renewal investment.

Our business faces a number of challenges

We are facing a number of challenges, as we progress our major network renewals. These include:

- improving service to customers, particularly reducing the number and length of planned outages
- catching up on asset replacement following historical under-investment
- strong growth in Central Otago requiring significant investment in network capacity
- building a new standalone business, and embedding new capabilities
- improving our asset management capability and aligning with good practice
- improving our processes to deliver better and more streamlined customer services.

Our investment plans and improvement initiatives will enable us to meet these challenges.

9 ISO 55000 is an international asset management standard that has been adopted by a number of leading utilities.

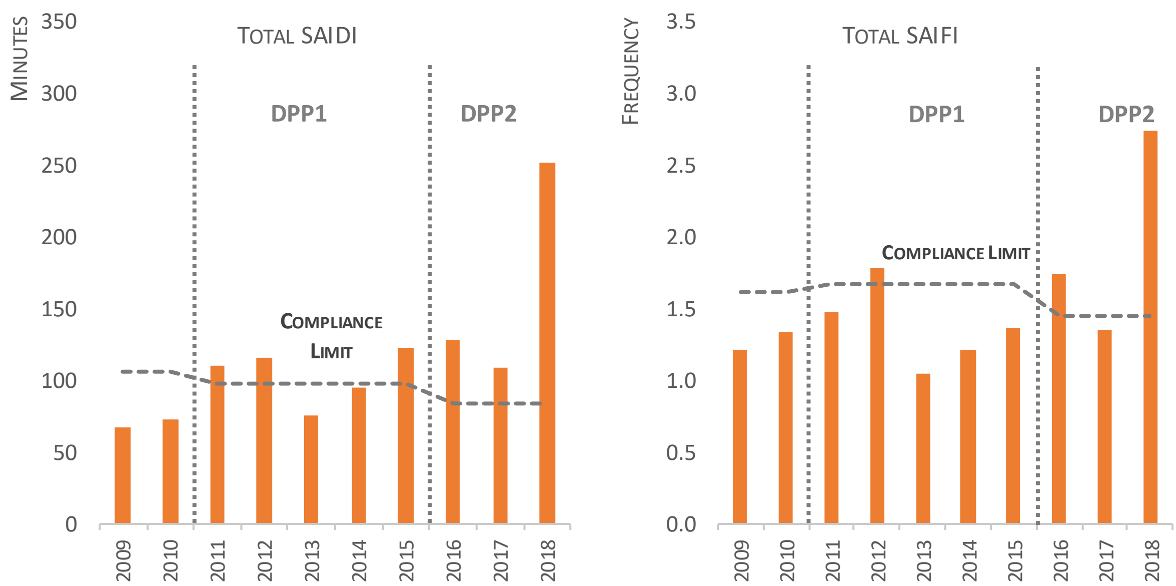
Reliability performance needs to improve

Our reliability performance, as measured by SAIDI and SAIFI, has deteriorated in recent years.[10] As shown below, we have failed to meet our SAIDI and SAIFI quality standards during the last four regulatory years. We understand that this level of performance is below what customers are used to and we aim to reduce the levels of planned and unplanned outages on our network.

We recognise that this level of performance is well below what customers have been used to.

While we have some reservations about using averaged indices to measure the service received by customers, we recognise that recent performance is well below what customers are used to, and will be seeking input on customer reliability preferences as part of building our CPP application.

Historical reliability (SAIDI and SAIFI) performance



We have analysed the drivers (see below) of this poor performance and have developed plans to address these over this AMP period. Further investigation is required to understand all the drivers of poor reliability and to anticipate and mitigate future causes of poor performance.

- **Increasing asset faults**: underlying reliability performance at specific locations across our networks is being impacted by a combination of increasing asset age leading to deteriorating condition, encroaching vegetation, and asset model or type-related issues.
- **Increased frequency and duration of planned outages**: these are necessary to undertake current levels of investment, particularly for overhead line work. As an example, approximately 70% of SAIDI in 2018[11] was due to planned work. The frequency and duration of planned outages has also increased due to a reduction in live-line work.

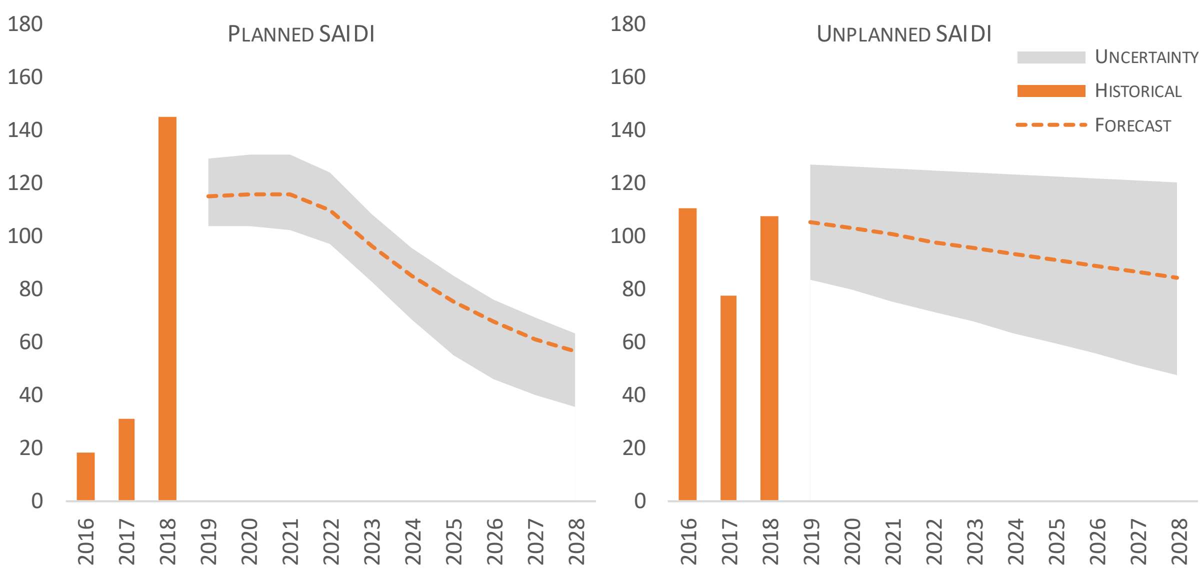
10 SAIDI and SAIFI measure average length and average number of outages, respectively, per customer per year.

11 Based on un-normalised, total SAIDI values.

- **Increased outage duration for safety**: across the sector, there is an increased focus on safety for the public and those working on or around electricity networks. On our network, the duration of outages has increased as a result of changes to operational practice for safety reasons. For example, we routinely patrol the length of a line following fault repair before turning the power back on, and during summer we suspend the use of automatic reclosers after trip faults to reduce fire risk.
- **Weather**: parts of our network appear to be becoming more vulnerable to severe weather and exceptional storm events.

Safety is our main focus and is driving the prioritisation of our current investments. Another important driver for our increased investment is ensuring that reliability levels are appropriate and that they reflect the price/quality preferences of customers.

Forecast SAIDI minutes (planned and unplanned)



The level of planned outages will continue in the medium term as much of our renewals work requires parts of the network to be de-energised so the work can be completed safely. However we expect their impact on planned SAIDI and SAIFI to reduce as pole renewal work volumes decrease and we widen our focus to increase zone substation renewal work. As depicted above, we expect unplanned SAIDI to improve slightly as our asset fleets are renewed. Not renewing the network would lead to an increase in unplanned outages and greater safety risks on the network. Chapter 4 sets out further detail on our reliability forecasts.

Future reliability

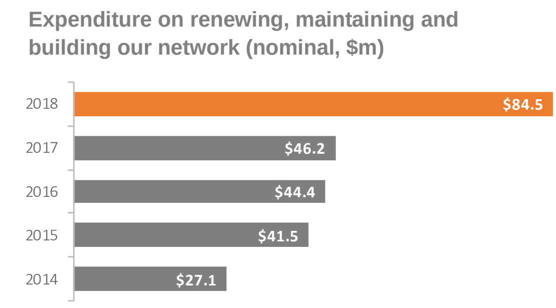
Accurately forecasting future reliability performance is challenging, as it is impacted by multiple factors such as asset condition, prevailing climate, new network configurations and technologies, and our capability to deliver our proposed interventions.

We have started an investigation to better understand the linkages between our proposed investment in this AMP and future reliability outcomes. We have included an 'uncertainty range' around our SAIDI and SAIFI forecasts to reflect the factors listed above. Based on further analysis, we will revise our SAIDI and SAIFI forecasts in our 2019 AMP.

A significant number of assets still need to be replaced

A substantial increase in asset renewal levels is required given the large proportion of assets constructed from the late 1950s through to the 1970s which are now reaching end-of-life. The main asset classes affected are support structures, overhead conductors, and zone substations.

The scale of uplift in our renewal work programme is illustrated by the substantial increase in capital and maintenance expenditure (see graph, right). In the last regulatory year (ended 31 March 2018), combined expenditure was $84.5 million, almost double the level of two years ago. This was driven by the instigation of our fast track pole programme and other asset renewal activities.



With historical expenditure levels, our asset fleets have deteriorated as they have aged. This is particularly true for overhead network assets. While age alone does not justify investment, it is an effective proxy for asset condition, which drives the need for most asset replacement and maintenance.

Historically, some parts of the network have not been adequately inspected, maintained and/or replaced. It is essential that we address this now. Over the past two years we have significantly increased our levels of investment in renewal and maintenance, but more needs to be done.

Delivering our planned renewal investment will help the customers and communities we serve to have confidence in their electricity supply and the safety of assets near their homes and businesses.

We need to build a new business

Our separation from Delta was undertaken over an accelerated timeframe, leading to some disruption to existing work plans and internal processes. The new operating model has also required the introduction of new functions to support arms-length works delivery and contract management.

This change has led to some resourcing constraints and uncertainty for staff impacted by the transition. Some capability gaps have emerged (e.g. in areas previously supported by staff who have remained in Delta), and we to need broaden capability and competency levels in some areas of the business.

While we are making good progress on this transition, it is essential that we maintain and, in some areas, accelerate the pace of change if we are to build an effective business that can meet the expectations of customers.

We need to continually improve our asset management capability

Our stakeholders expect us to be able to clearly demonstrate that our network is well managed, our assets are safe, and we operate the business efficiently. This requires us to understand the health of our assets, how they are performing, where future demand is likely to arise and the residual risk that it is appropriate for us to manage.

We have sought advice and undertaken reviews in the following areas:

- safety culture
- asset health modelling
- service delivery and contracting arrangements
- workflow processes and project management.

To lay the foundations for improving our overall performance, and to meet the challenges outlined above, we have critical business improvement initiatives planned or already underway. Our latest AMMAT assessment (see Chapter 7) has resulted in a score of 1.94. This is lower than previously reported by Delta (which drafted previous AMPs on behalf of Aurora Energy). The gaps identified during this review will be addressed as part of our updated Asset Management Development Plan (AMDP – see Section 7.1.3). Key focus areas include:

- Engineering competency: sufficient engineering competency – enough people with the right skills – will be a key determinant of our success in achieving our asset management objectives. Developing and broadening staff capability will be a key focus. Effective leadership is crucial, and we will require appropriate structures, processes, roles and responsibilities and contractual relationships.
- Works delivery capability: our ability to successfully deliver our planned level of investment at efficient costs will depend on having the right specialist skills, improved project management processes, and the necessary supporting information. This will include the use of improved procurement and logistics to reveal efficient market rates, use of standardised solutions, and improving the utilisation of our service providers.
- Asset management decision-making: we will require robust asset data, models and processes to ensure we understand the current and expected future performance of our assets over their full lifecycle, and the overall health of our network. In particular, risk-based decision making will be supported by improved asset health modelling and embedding criticality into our forecasts. Expanded programs of physical inspection and testing will ensure we are collecting the right data at the right time. Improving our forecasting techniques will enable us to model (with increasing accuracy) the required levels of future investment.
- Strong analytical capability: our asset management improvements need to be underpinned by strong analytical capability. If we are to successfully optimise future investments and manage network risk there will be an increasing need for reliable information and expanded capability, and improved systems. Accurate and reliable asset data and modelling is an essential input.
- Network planning: our demand forecasting methodology and load flow models will need to be updated and expanded to model future load scenarios. These innovations are important if we are to pursue 'least-regret' investments.

These focus areas will support improved efficiency and effectiveness, and are directed towards aspects of our business systems, processes and culture where improvement is most warranted. In many cases, these initiatives implement recommendations from independent reviews, reflecting knowledge and experience of approaches adopted in other distribution companies.

Ultimately, the objective of these improvement initiatives is to provide customers with a safe and reliable electricity distribution service in accordance with their needs and expectations, whilst minimising the whole-of-life cost of managing our assets. The linkages between our initiatives and quality improvements or efficiency gains is complex and often lagged. As a result, we expect that the impact of these initiatives on our performance will be gradual, noting that many of them will take a number of years to fully implement. The initiatives are aligned with our new corporate and asset management objectives, and these objectives will not be met unless improvements are achieved.

The need for increased investment remains

Since our 2017 AMP, our forecasts have been further refined, in terms of priority and timing, based on subsequent improvements in asset knowledge and updated risk assessments. In particular, our 2018 AMP investment plans have been developed to:

- Keep our networks safe: we have an uncompromising approach to safety. We always take action where we believe there are safety risks. There is evidence of increasing failure risk and we are increasing our level of investment in overhead line assets to ensure this risk is effectively managed. To support this our focus has been on developing our understanding of asset health and criticality to ensure our investments are targeted to manage risk and can be linked to network and customer outcomes. Emerging views from the independent review, which supports improvements in these critical areas, have helped with this. We will also progressively replace switchgear and other assets to reduce the safety risk posed by failure of these devices.
- Ensure prudent asset renewal: a backlog of assets in poor condition has been growing and this has led to increased levels of network risk. We are prioritising investment based on asset health and criticality. For poles, our plan is addressing the legacy of a prolonged period of under-investment. Within three years, our poles will be in a stable, managed state of inspection and renewal. We have increased our focus on understanding the condition of our overhead conductor assets and are establishing our conductor replacement programme. As part of a wider programme, we have started to replace our ageing Dunedin 33 kV cables to avoid the potential for a growing backlog of work. While these cables are not a risk to public or worker safety, they do present an emerging network reliability risk.
- Deliver a reliable service: we have not met our reliability targets in recent years and are now seeing increased asset failure risk on some parts of our network, which is increasing pressure on our reliability performance. Our condition assessment and inspection data indicates that these trends are linked to a higher proportion of our assets reaching the end of their useful lives. We are committed to addressing these trends through targeted investment across our network.
- Support future growth: parts of our network, in particular Queenstown and surrounding areas continue to experience load growth. We foresee continuing growth in business sectors as well as increasing options for our residential customers to adopt technologies such as rooftop solar generation and electric vehicles. Our investment plans will support the capacity and security needs of customers. Ensuring we can support regional growth is a focus for us.

We are committed to sustaining the required levels of investment

Our expected total investment over the planning period is set out below. This, and the expenditure profiles on the following page, represent our best estimate of network needs based on currently available information. They reflect our current levels of delivery capability and the need to avoid uneven work volumes. We will reprioritise work as we obtain better asset information or refine our current assumptions. This includes adjusting our spending – if prudent to do so – to meet new or diminishing risks, and meeting the long term interests of customers.

We are committed to increasing our investments to ensure customers receive a safe and reliable electricity service.

A sustained higher level of expenditure is necessary to stabilise network performance. We are focussing on investment to replace assets that are no longer meeting their required performance levels. The following table sets out our ten-year planned expenditure from our AMP 2017, our interim forecasts published in March 2018, and our final AMP 2018 forecast. The latter includes works initiated or expanded as a result of WSP's interim findings.

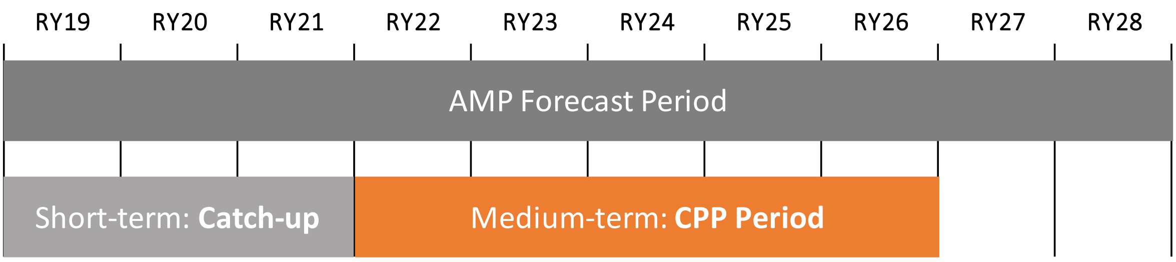
Ten-year network expenditure (nominal dollars, including customer contributions)

	2017 AMP	Interim 2018 AMP	2018 AMP
Capital expenditure	$527.5m	$532.9m	$592.8m
Operating expenditure	$191.1m	$194.6m	$155.6m
Total network expenditure	**$719.4m**	**$727.5m**	**$748.4m**

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. Similar to other electricity distribution businesses, the accuracy and granularity of our forecasts will vary over the period. Reflecting this, our forecasts can be divided into two periods:

- **Short-term catch-up**: over the next three years (RY19 to RY21) we have comprehensive plans primarily focussed on addressing the backlog of renewals, priority growth projects, and ensuring we deliver customer-initiated work.
- **Medium-term CPP period**: over the following five years (RY22 to RY26). This period is our planned CPP period. Expenditure during this period will be informed by consultation with customers and be subject to detailed scrutiny by the Commerce Commission.

This AMP covers a catch-up period and CPP period

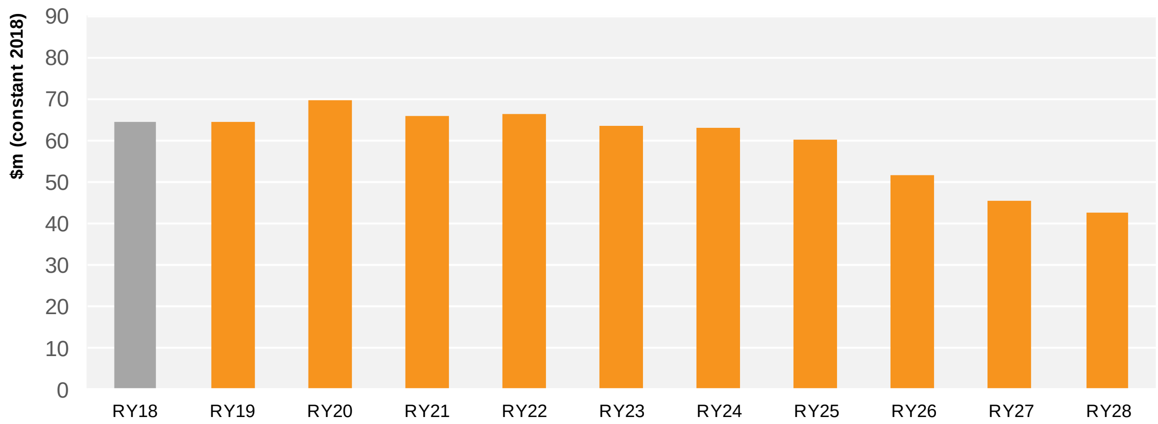


Our expected investment over the planning period is set out below.

Capital expenditure

Planned capital expenditure on our network is slightly higher than our 2017 AMP forecast and our March 2018 interim disclosure. It continues to represent a significant increase on historical levels. This level of expenditure is needed due to our ageing asset base and is important to ensure a long-term safe and reliable supply for customers.

Total Capex during the AMP period ($m, constant 2018, net of customer contributions)



What assets we plan to invest in:

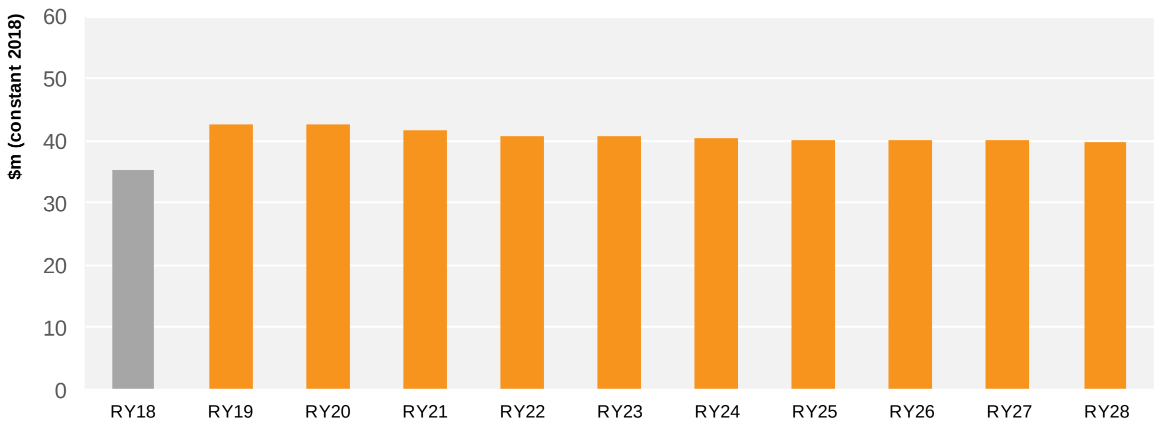
- Maintaining our accelerated pole-replacement programme for up to three more years, before returning to steady-state levels (discussed in Chapter 5)
- Increasing conductor crossarm renewals over the period, as we progressively firm up information on their condition (discussed in Chapter 5)
- Renewing Dunedin's 33 kV cable network, as part of a broader review of the city's network architecture (discussed in Chapter 5)
- New or increased capacity assets to provide the capacity required to serve growing communities in Arrowtown, Wanaka, Queenstown and Cromwell (discussed in Chapter 6).
- Implementing new ICT systems, and supporting processes, in the early part of the CPP period, including an integrated asset management system.
- Replacement of poor condition assets in other fleets that present safety risks, particularly ring main units (RMU) and air break switches (ABS).

Operating Expenditure

Our planned Opex is expected to be relatively stable over the AMP planning period.[12] In the short-term we expect to continue to incur costs related to our transition to a standalone business and to help develop our CPP application. We plan to increase our maintenance management activities, though this increase will be somewhat offset by expected savings as we increase the level of contestability through new service providers. The high level of vegetation management spend will continue in the short term until we have fully embedded cyclical vegetation management across our networks.

[12] Although not reflected in the long-term forecast, we expect to achieve productivity and efficiency improvements to reduce costs. We have not attempted to model these at this early stage.

Total Opex during the AMP period ($m, constant 2018)



What activities will drive Opex during the AMP period:

- We plan to bring our vegetation management practices up to good industry practice by adopting a cyclical inspection regime, and risk-based assessment of out-of-zone trees.
- Improved inspection techniques will be adopted, to better understand asset condition and network risks. Data and information management practices will be enhanced.
- We are pursuing improvements in the way we practice asset management, to achieve industry good practice and to realise improved efficiencies in the future. To achieve this, we will bolster our internal capabilities and skills.
- Our project delivery capacity will need to be increased to ensure we can effectively and efficiently deliver required investments.
- Additional business support staff to support our transition to a standalone business and to improve our ICT systems and capabilities (e.g. an enterprise asset management system).
- We expect productivity and efficiency improvements to offset upward cost pressures in the latter part of the AMP period.

We have already begun to refine these forecasts based on the outcomes of the initiatives discussed above and our improving asset information and modelling. This process will incorporate the outcomes of the independent review and associated stakeholder feedback. We will update our forecasts in our 2019 AMP, to be published in March next year.

Investments focus on key asset classes

The table below provides a summary of planned investment over the AMP period. References to H1-H5 reflect the definitions in Table 5.1 of this AMP (Asset Health Categories). Assets classified as H1 have reached the end of their useful life, and we aim to replace them within 12 months.

Summary of asset fleet investment

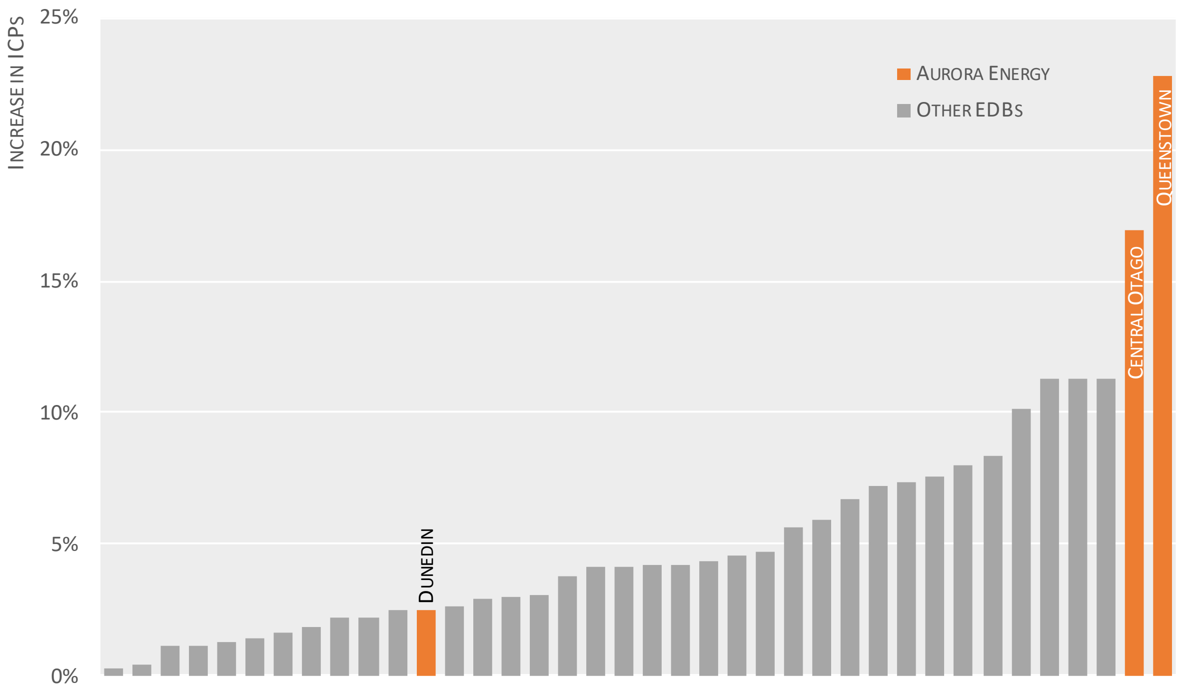
Asset	Current state	Expected outcome 3 years	10 years	Spend	What our planned investment will achieve
Poles	7% H1	<1%H1	<1%H1	$150 m	The immediate focus is to remove the remaining red-tagged poles (prioritised by safety criticality) by June 2019. (In the 18 months to June 2018, 9% of the pole fleet have already been replaced or reinforced).For the first 3 years, pole replacements and refurbishments will continue at a rate of 2,000-plus a year to address the backlog and reach a steady-state where all red tagged poles are addressed within 3 months of identification. At the end of 3 years, the volume of category H1 poles will have reduced from 7% to under 1% of the fleet. It will be maintained at that level for the remainder of the 10 year period.
Crossarms	44% beyond expected life	50% inspected	<1%H1		Many crossarms that have exceeded expected life will be replaced in conjunction with pole renewals; others will be replaced as part of a standalone crossarm renewal programme. In 3 years, 50% of cross arms will have been inspected, their condition assessed, and asset health determined.
Overhead conductors	14% H1	<10% H1	<1% H1	$55 m	In 3 years, 256 km of overhead conductor (wires) will be replaced, based on age, condition and criticality.
Sub-transmission UG cables	42 km to be renewed	15.8 km replaced	All H1 replaced	$40 m	A major replacement programme will see the progressive upgrade of older 33 kV subtransmission cable in Dunedin.
Distribution and LV UG cables	0.5% H1	<2% H1	<1% H1	$14 m	This fleet is in good health and is considered to have low safety and reliability risk. We forecast relatively low levels of PILC type cable replacement for later in the AMP period to maintain a reasonable level of asset health and low levels of reactive replacement.
Distribution switchgear	9% H1	<5% H1	<1% H1	$31 m	To reduce safety and reliability risks, approx. 600 units are forecast for replacement over the next 3 years.
Distribution transformers	6% H1	<1% H1	<1% H1	$41 m	Approx. 500 units are forecast for replacement over the next 3 years. Many of the pole mounted transformers will be replaced during pole replacement work.
Zone substation (ZS) power transformers	27% H1	27% H1	<11% H1	$20 m	Current asset health is age-based and is considered relatively conservative. We do not plan to start condition-based transformer replacements until 2022. Detailed condition assessment will be undertaken to support planning and prioritisation. Note that many of the H1 power transformers are at sites with duplicated transformers and back up network contingency plans and hence, are considered relatively low risk.
ZS circuit breakers	34% H1	23% H1	<1% H1	$27 m	ZS switchgear will be replaced in conjunction with other zone substation-related works. High criticality sites will be addressed first.
Secondary systems	776 EM/S[13] relays remain	464 EM/S relays (60%) remain	<3% of EM/S relays remain	$17 m	The majority of our obsolete relays will be replaced over the ten year period either as targeted work or as part of a zone substation upgrade or replacement project. Modern protection systems enable better fault identification and faster clearance times, thereby reducing fault energy levels, improving safety and enhanced network reliability performance.

13 EM/S is an abbreviation for electromechanical and static relays.

Serving Growth in Central Otago and Queenstown Lakes

Our network supplies the two fastest growing regions in the country by customer connections – Queenstown Lakes and Central Otago, which have seen 23% and 17% growth, respectively, over the past five years. In comparison, the growth rate in Dunedin is below the national average.

Growth in electricity connections (five-year percentage change from 2013 to 2018)[14]



We have been responding to the growth in electricity demand resulting from new residential developments, tourism and irrigation. For example, to cater for increased demand in the last three years, we have built new substations at Lindis Crossing (near Cromwell), Camp Hill (near Hawea), Lauder Flat (Omakau) and most recently Riverbank Road in Wanaka.

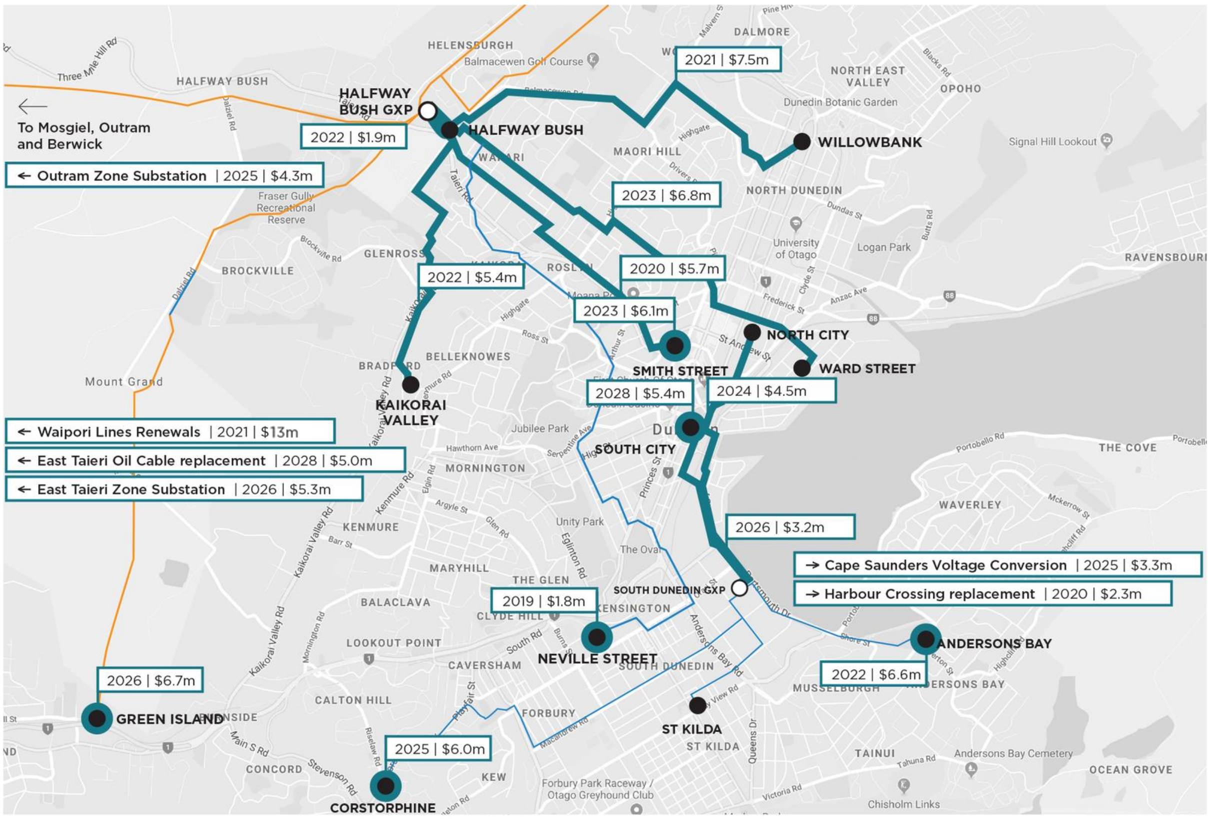
We have actively engaging with local councils to ensure our assumptions and planned investments are aligned with their priorities and development plans. The next ten years will see further network investment to provide capacity to service the demands of growing communities in Cromwell, Arrowtown and Queenstown. Planned investments include an upgrade to triple transformer capacity at the Cromwell zone substation (scheduled for RY19-20), transformer installation at Riverbank Road to relieve Wanaka substation, and a substation upgrade and feeder reinforcement for Arrowtown.

Summary of large projects

Over the next ten years we plan to spend over $150 m on large projects to renew, upgrade and expand our networks. A selection of these projects are set out on the three maps below, colour coded to denote whether the investment is driven by renewal or growth. These works are in addition to our programme-based work such as pole renewals.

[14] Electricity Market Information website, Growth in electricity connections from September 2013 to August 2018 by ICP by network reporting region

Large planned projects in Dunedin



Grid Exit Point | Zone Substation | 33kV overhead line | 33kV underground cable | Renewal project

The year indicated for project completion ends at 31 March in each case.

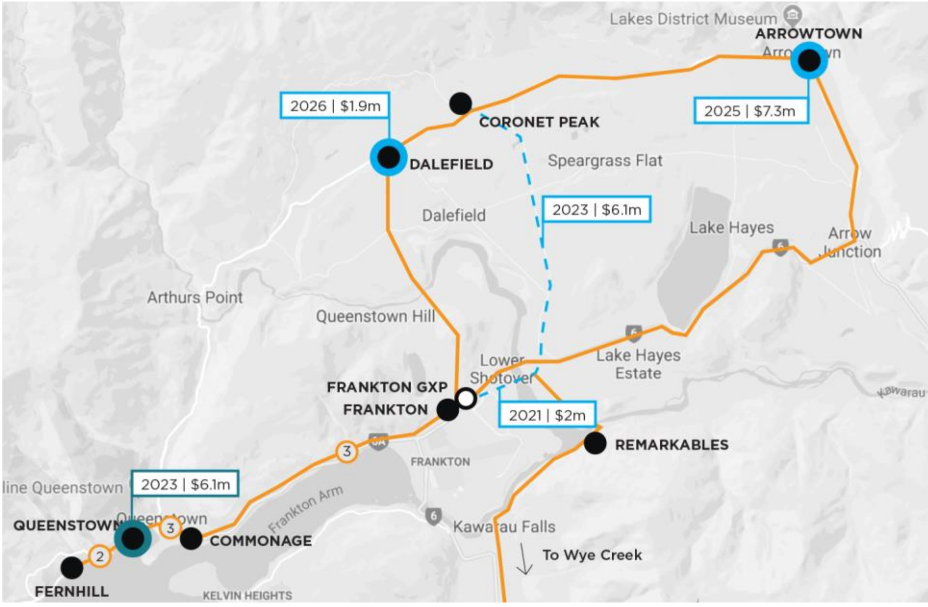
Much of the Dunedin network was constructed 50-70 years ago and many of its assets are near end-of-life, requiring renewal over the AMP period. This coupled with historical low rates of replacement mean we will replace assets including 33 kV cables, power transformers and switchgear over the AMP period. Example projects include:

- rebuild of the Waipori subtransmission pole lines from Halfway Bush to Berwick
- the steel lattice structures and associated poor condition conductors that span Dunedin harbour
- the Neville St substation, to be replaced with a new zone substation at Carisbrook. This project is underway, with the majority of the new substation complete.

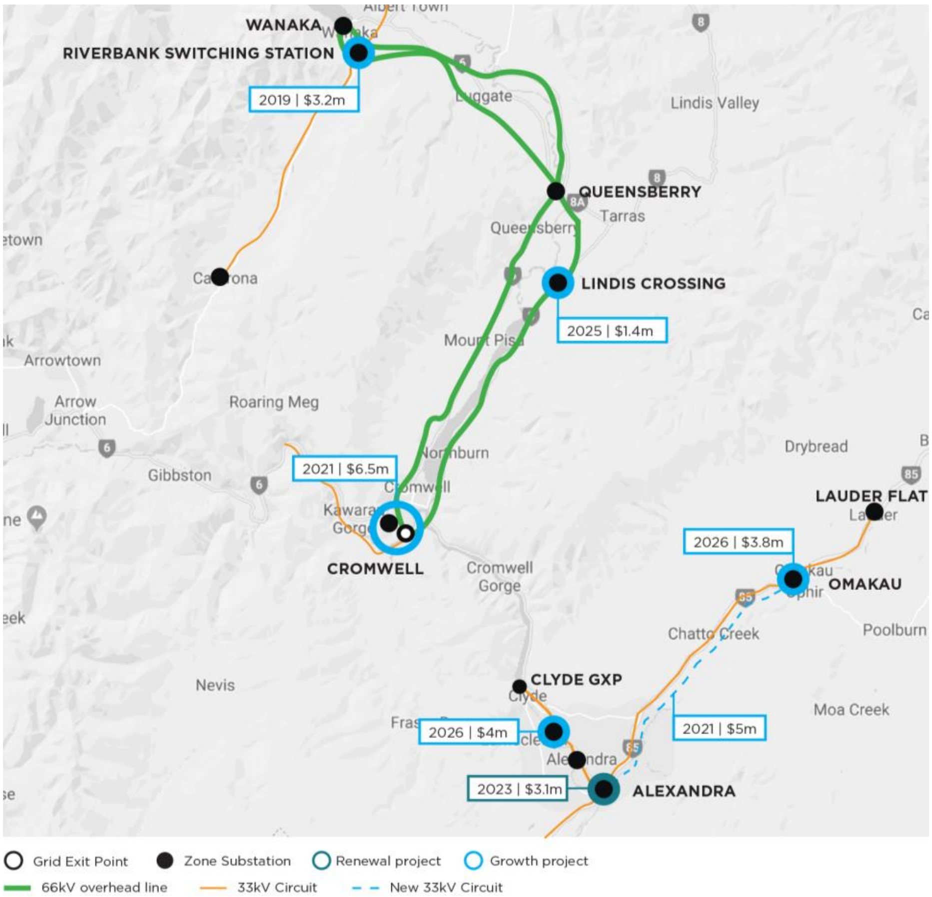
No growth projects are planned for the Dunedin network.

In contrast, large projects on our Central Otago networks (shown in the following two maps) are driven by demand growth, including residential development and expanding tourism operations. As discussed above, we expect this region to continue to grow and we are engaging with local councils to ensure our investments facilitate this growth.

Large planned projects in Queenstown Lakes and Central Otago



We plan to build a new feeder from the Frankton GXP to the Shotover River to increase the capacity of the Wakatipu Ring, later supplemented by a project that extends the feeder to Coronet Peak.



We are planning a larger number of growth projects, including upgrades of the Arrowtown, Dalefield, Lindis Crossing, and Cromwell zone substations and the Riverbank Road switching station. We will also build a new 33/11 kV line to supply Treble Cone ski field and a second 33 kV line to Omakau.

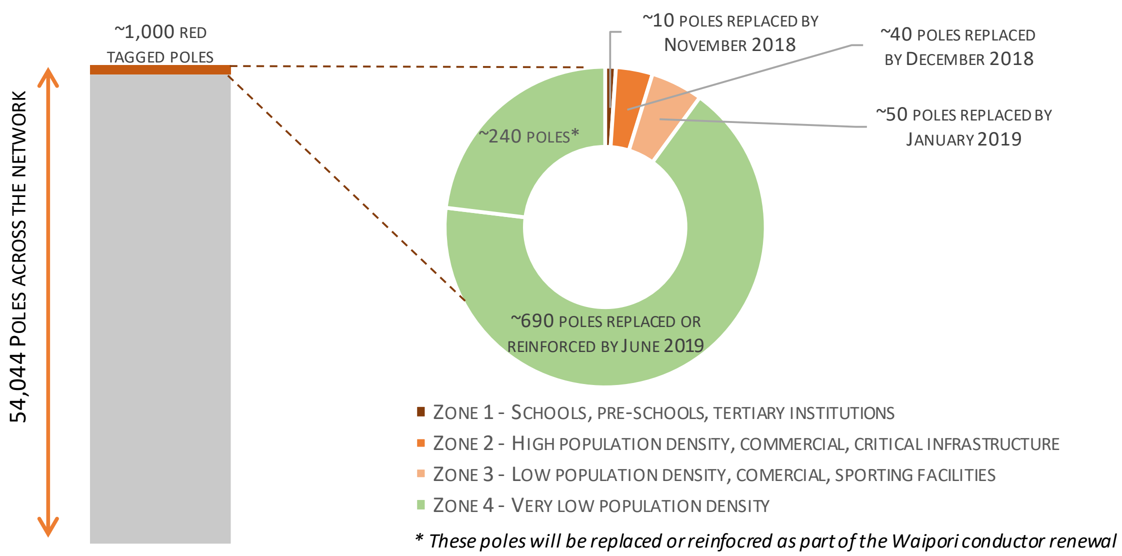
Future poles programme

Our pole programme will continue at elevated rates of renewal for up to three further years to address the remaining backlog of poor condition poles, before returning to steady-state levels. During this period, we will:

- remove the backlog of red-tagged poles by pole replacement and strengthening, prioritised by public safety criticality, by June 2019 (see figure below)
- over the next three months, identify high risk poles by visually checking all current red-tagged poles that have not been subject to our current condition testing methodology
- increase pole inspections to confirm overall fleet condition and defect numbers, prioritised by network criticality, to ensure all poles have been inspected within a 5 yearly-cycle by RY20
- continue the pole renewal programme to ensure the pole fleet is maintained in an acceptable condition and that end-of-life poles are remediated within required timeframes.[15]

Our urgent priorities are to address the backlog of red-tagged poles and test poles in high criticality areas. We have prioritised the testing and remediation work based on public safety risk and are replacing those in higher density population areas first, as outlined in the diagram below.

Red-tagged poles and our planned remediations (as at 4 October 2018)



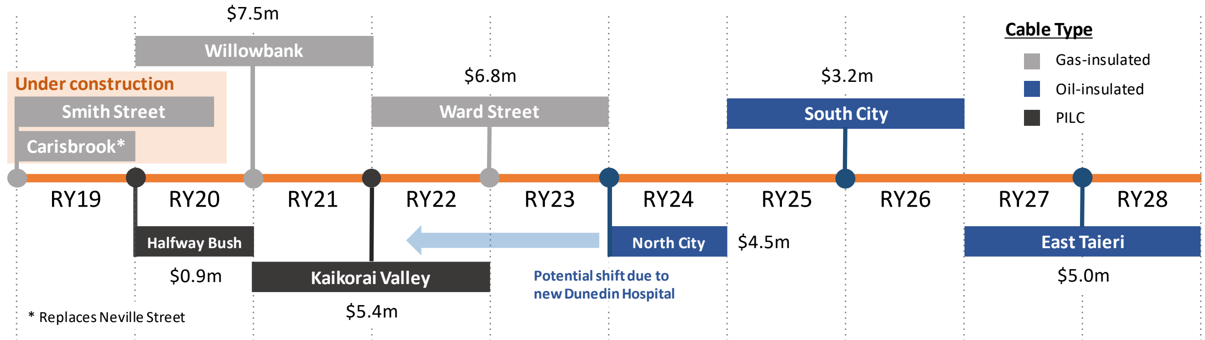
Given the age and asset health profile of our pole fleet, we are aware that we will continue to identify poles requiring replacement at an elevated rate over the next three years. However, we have the capacity to replace these more quickly than has historically been the case.

[15] Consistent with the Electricity (Safety Regulations) 2010, structures assessed as being at risk of failure under normal structural loads must be red tagged while those that are incapable of supporting design load must be orange tagged. Replacement or refurbishment is required within 3 or 12 months, respectively. To date, we have also used a blue tag to indicate equipment defects or encroaching vegetation. We are currently considering discontinuing this practice given that blue tag defects are non-structural.

Dunedin cable network

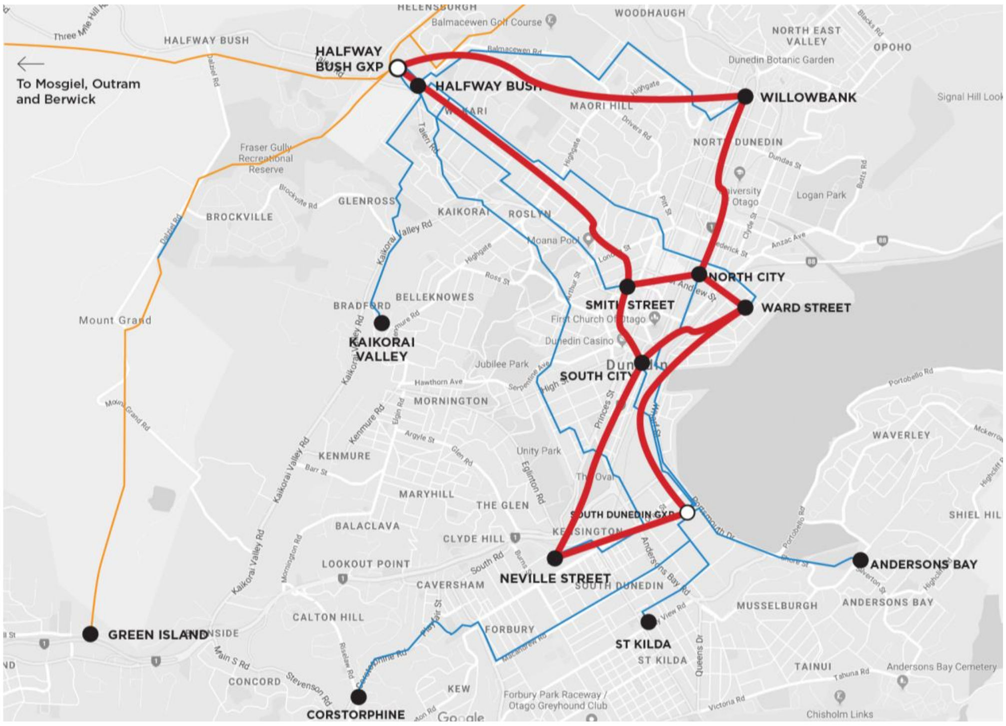
The backbone of the grid supplying Dunedin is the subtransmission cable network. A series of high voltage 33 kV underground cables take supply from the national grid at Halfway Bush and South Dunedin and distribute it to zone substations throughout the city.

Planned Dunedin 33 kV subtransmission cable replacement[16]



As most of the city's subtransmission cable is coming due for replacement, we have been progressively upgrading the older types of gas-filled, oil-filled and PILC cables to modern cables that use solid insulation. The Andersons Bay, Carisbrook and Smith Street cables have been replaced or are under construction. As shown above, we plan to replace most of the remaining subtransmission cables.

Potential reconfiguration of the Dunedin subtransmission network



At the same time as renewing the cables, we are investigating a plan to reconfigure the subtransmission network to enhance its resilience in the event of a major event such as an earthquake. The current hub-

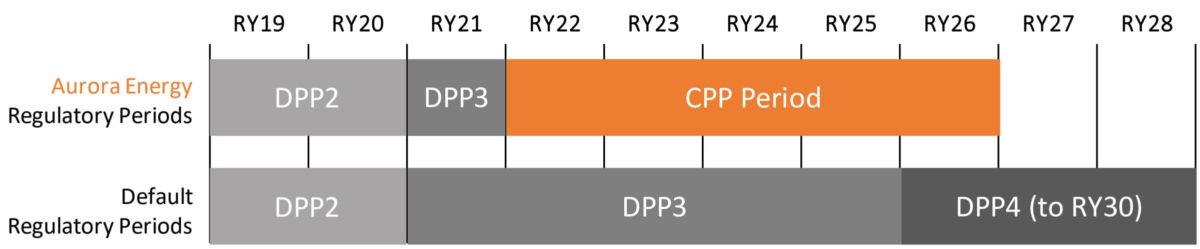
16 The new Dunedin Hospital (scheduled during the AMP period) will require changes to the North City substation and the sub-transmission cables that supply it. The North City cable replacement project may be brought forward to facilitate this.

and-spoke arrangement would change to a meshed network with more interconnection, providing flexibility to switch supply between grid exit points and zone substations. Our 2019 AMP will report on the conclusions of our investigation including any changes to the cable renewal timing and costs.

We will submit a CPP proposal in 2020

A CPP is a regulatory mechanism that a utility can use to seek a price-quality path (comprising expenditure and reliability standards) based on its own circumstances (e.g. it expects to undertake significantly higher network investment than is provided for under a DPP). The Commerce Commission carries out a review of the company's future plans and whether these are prudent, efficient and in the long term interest of customers. We will submit a CPP application to the Commission in May 2020 and transition to this mechanism in April 2021. This will be necessary if we are to deliver a safe and reliable service to customers, over the long term.

Aurora Energy will move to a customised price-quality path in RY22



As part of our process to develop a CPP application, we will undertake a series of detailed consultations with customers, including on:

- network safety
- feedback on the independent review
- price-quality preferences
- network resilience
- future technology expectations.

The investment we are making now and expect to make over the next decade is a significant increase on historical levels, and well above our current regulatory allowance determined by the Commission under the DPP. This means that a proportion of the investment we are now making will never be recovered or reflected in our prices, and we will earn lower returns than the Commission generally considers reasonable.

This timeline set out above means we will retain current DPP expenditure allowances for at least the next two years. However, as set out above, we will maintain our elevated levels of investment during this time despite the significant financial implications of overspending our allowance. During this period we will continue refining our investment plans and refocussing our activities as needed.

The CPP process provides a mechanism for the Commerce Commission and stakeholders to review and provide input to our proposed investment plan before we finalise plans for implementation.

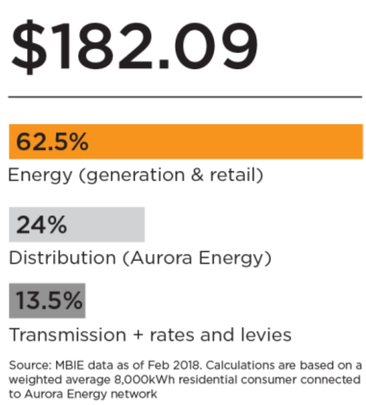
Future Prices

To deliver the safe and reliable service our customers expect over the long term will require funding that better reflects the cost of upgrading and maintaining our assets. All things being equal, increased investment places upward pressure on prices and we are working hard to minimise this cost impact on customers. While any price increase is unwelcome, our network prices have not increased for an extended period and benchmark low against the rest of the sector.

As part of consulting on our CPP proposal, we will provide customers with meaningful information about different investment options and what they will deliver. In some areas, expenditure is necessary for safety or compliance and there are few or no alternatives. In other areas, there are options and the level, timing and focus of network spend can be adjusted to reflect customer preferences around price, reliability and resilience. The CPP process enables us to determine these preferences.

Our objective is to be a transparent as possible about our investment plans and how different choices may impact customer pricing. The first noticeable increase to our prices will happen when the Commerce Commission resets the DPP in 2020 and our increased network expenditure in recent years is reflected in future prices. The Commerce Commission will be consulting on the DPP reset during 2019. Any change to our pricing under the new DPP will apply for one year, from 1 April 2020 to 31 March 2021, before we move to a CPP from 1 April 2021.

The graphic to the right shows the composition of an average monthly bill on our network.



A final word on safety

This AMP has been developed with a focus on ensuring our network can be re-positioned to safely deliver the service customers expect. This means increasing our investments and improving our asset management capability to minimise the potential for assets to cause harm.

Our AMP includes a number of important improvement initiatives and critical investment programmes. While delivering these, we will not compromise our efforts to ensure the safety of our staff and the general public. This will always be our foremost priority, and informs everything we do.

SAFETY NOTHING LESS

Safety Pledge

We will strive for 'safety, nothing less', meaning all our activities and decisions will focus on safeguarding the public and ensuring an injury free workplace.

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1. INTRODUCTION

This chapter introduces Aurora Energy's 2018 Asset Management Plan (AMP).

1.1. PURPOSE OF THE AMP

The AMP outlines our long term strategy for managing our network and the asset management approaches we use. It explains how we intend to manage our network over the coming years to meet the expectations of our stakeholders.

In the AMP we set out our planned investments for the coming 10 years. These will allow us to develop and expand our services, renew and maintain our assets, and continue to provide a safe, reliable and valued service to customers.

We intend to use this AMP as a basis to consult with our stakeholders, particularly on our planned investments. We hope that it will help stakeholders to understand our approach to managing our network assets.

1.1.1. AMP Objectives

This AMP meets the requirements of the Electricity Distribution Information Disclosure Determination 2012. Our cross reference of how our AMP meets the detailed regulatory information disclosure requirements is shown in Appendix G. In addition to these requirements, we have developed our AMP to demonstrate responsible stewardship of our electricity distribution network.

The objectives of our AMP are to:

- reaffirm our commitment to minimising safety risks on our network
- highlight our approach to managing long life assets by providing clear descriptions, objectives and targets for them
- be transparent with our stakeholders, particularly around the risks inherent in the network and the systematic processes in place to mitigate those risks
- provide visibility of forecast investment programmes to external users of the AMP
- set out our corporate mission and vision and how these inform our asset management approach
- summarise our asset management document suite, show how these are aligned with corporate goals and set out our work plans for the planning period
- demonstrate the interaction (or line-of-sight) between the objectives of the AMP and other corporate goals, business planning processes, and plans
- explain the challenges we face and why we will apply for a CPP
- highlight recent improvements in our asset management practices.

We believe this AMP will be informative and welcome any comments or suggestions by emailing: info@auroraenergy.co.nz.

1.1.2. Period Covered by the AMP

Our AMP covers a 10-year planning period, from 1 April 2018 to 31 March 2028.

The AMP is a live document and as a result will change over time as new information is incorporated into our decision-making and as our approach to asset management is refined.

As might be expected, the first five years of the AMP are based on more detailed analysis of demand forecasts and asset information, resulting in a relatively high degree of certainty. The latter period of the AMP is progressively less certain and is suitable for provisional planning purposes only.

1.2. STRUCTURE OF THE AMP

The chapters and appendices that make up the AMP are set out below.

Chapter		Appendix	
Introduction This chapter.	1	**Glossary** An appendix that sets out the meaning of acronyms and technical terms.	A
Background Provides context for our AMP and explains how our business has changed since we published our previous AMP in March 2017.	2	**Information Disclosure Schedules** Technical and financial disclosures, asset management maturity assessment and background on disclosures.	B
Network Overview Describes our networks in Dunedin and Central Otago and sets out some key statistics.	3	**Reliability Management Plan** Provides further detail on our plans to improve our reliability performance over the planning period.	C
Strategy and Governance Explains how we make asset management related decisions, and how we ensure our investments support the needs of stakeholders.	4	**Further Risk Management Information** Provides further detail on our approach to risk management.	D
Lifecycle Management Summarises our approaches to managing our network assets throughout their lifecycle.	5	**ICT Asset Information** Provides further detail on our ICT assets and systems, and how we manage them.	E
Network Development Summarises our approaches to developing our network and connecting new customers.	6	**Major Projects Detail** Provides further detail on our larger network investments over the AMP period.	F
Asset Management Enablers Discusses the activities we undertake to support our core asset management activities.	7	**Disclosure Requirements** Sets out how the AMP addresses relevant information disclosure requirements.	G
Financial Summary Sets out our planned investments over the AMP period.	8	**Director Certificate** A copy of the AMP's director certification.	H

2. BACKGROUND

This chapter provides background on our business and explains how we are regulated. It is structured as follows.

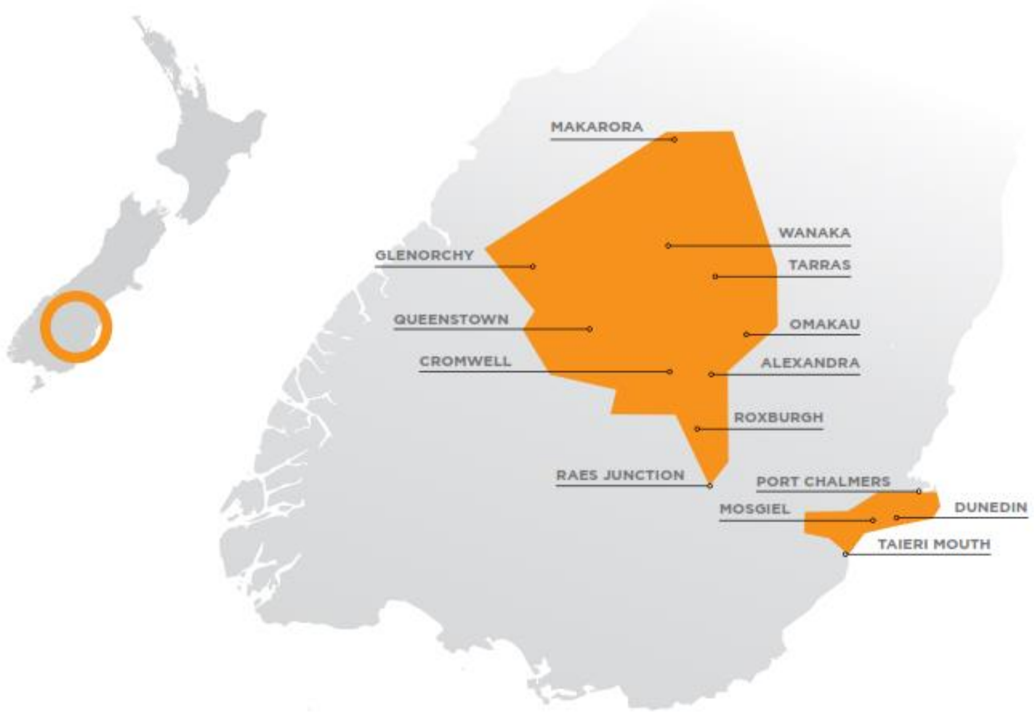
- **Overview of Aurora Energy:** provides background information on our business, its new corporate structures, and new governance arrangements.
- **Our stakeholders:** explains who our main stakeholders are and discusses their needs.
- **Context for our 2018 AMP:** sets out the context impacting our 2018 AMP, including several initiatives that have been undertaken since our last AMP was published in March 2017.
- **Regulatory context**: explains how we are regulated, and the role of the AMP in supporting our interactions with the Commerce Commission.

2.1. OVERVIEW OF AURORA ENERGY

Aurora Energy owns and operates electricity distribution network assets in Dunedin and Central Otago (including Queenstown Lakes). We own and manage a wide range of assets that are used to transport electricity from the national grid, owned by Transpower, to end-use consumers.

Our role is to ensure the safety and resilience of the network, supplying a reliable electricity service to close to 90,000 homes, farms and businesses throughout the regions we serve. Chapter 3 discusses our networks in more detail and describes the main customers in each region.

Figure 2.1: Aurora Energy Network Areas



2.1.1. A New Business

Aurora Energy was set up as a new organisation in July 2017, although we can trace our history back to the early days of power generation in Otago. Today, we have more than 130 staff based in Dunedin, Cromwell and Frankton dedicated to running the network and supported by our team of contractors in the field.

Up until 1 July 2017, Delta undertook asset management and service provider roles on behalf of Aurora Energy, the asset owner. Following some concern around the then governance and management arrangements, an independent review was commissioned. The outcome was that Dunedin City Holdings sought the formal separation of the two businesses, and Aurora Energy formally separated from Delta. This decision saw 100 staff transfer to Aurora to independently carry out asset management, engineering design, and corporate services. The separation is largely complete, with the transition of a number of non-commercial shared services functions to be completed in the coming months.

Under the new operating model, Delta is an arms-length service provider subject to commercial terms. In 2018, following a contestable tendering process, we appointed two additional contractors – Unison Contracting and Connetics – to deliver our Dunedin and Central Otago works programmes alongside Delta. We also plan to tender major projects – such as substation rebuilds and line construction – to pre-qualified firms. We will ensure a controlled integration of our new suppliers by gradually increasing the volume and scope of contestable work over time.

Benefits of the new arrangement

The separation ensures that dedicated, focused governance and leadership are applied to the ownership and operation of our electricity assets, without the need for the wider focus required to also manage a contracting business (as was the case in the past). Delta will continue as a core service provider for vegetation management and fault response, while other maintenance, renewals and growth investments will be carried out across the three contractors.

Structural separation will create clearer accountabilities for the two entities' network ownership and service provision, respectively. It allows increased transparency and commercial tension in our procurement processes. These benefits have the potential, over time, to reduce the underlying cost of delivering our service to customers.

Short-term impact

The separation was undertaken in an accelerated timeframe, with the majority of the transition planned and executed during the period February to July 2017.

The separation process led to disruption to existing work plans and workflow processes and methods. The new operating model has required new processes to be embedded, the replication of certain functions, as well as the parallel operation of others.

This process has inevitably led to some resourcing constraints and uncertainty for staff impacted by the transition. Some capability gaps have emerged, for example in areas previously supported by staff that have remained in Delta, or where there are services being provided by Aurora that were not previously undertaken or resourced. This has led to a need to broaden capability and competency levels in the new business.

2.1.2. Ownership and Governance

This section describes the governance arrangements, organisation structure, and key responsibilities of our Executive Management, Asset Management, and Operational teams. The aim of the governance arrangements and organisational structure is to ensure the necessary accountabilities are in place for good asset management.

Ownership

Aurora Energy Limited is a subsidiary company 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. The Board is responsible for the direction and control of the company including commercial performance, policies, budgets and compliance. The Board receives formal updates from management on our progress against objectives, legislative compliance, and risk management, and performance against targets.

Our Board

The Board is responsible for enabling the organisation to secure the resources necessary to implement its programmes and services to accomplish its mission, vision, and goals. To support this role, it has established policies to safeguard and guide the use of resources and assets, including appropriate risk management. This extends to ensuring clear and accountable performance management.

Our Board reviews and approves our AMP and ensures that the AMP meets regulatory requirements. This AMP was approved by our Board on 17 October 2018.

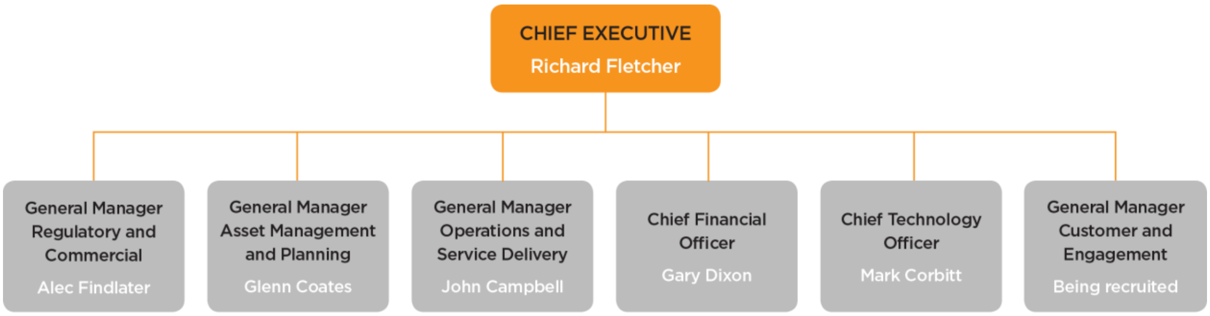
Overall governance and decision making rests with the Board of Directors and CEO. The Aurora Energy Board provides strategic guidance, monitors the effectiveness of management, and is accountable to shareholders for the company's performance. From an asset management perspective, the Board does this by endorsing key documentation (including this AMP) that establishes our objectives and strategies for achieving those objectives, and monitoring performance. The main asset management responsibilities of the Board are as follows.

- The Board has overall accountability for maintaining a safe working environment and ensuring public safety is not compromised by our assets and operations.
- The Board reviews and approves our AMP, which includes our medium-term (10-year) investment plans, and ensures that the AMP meets regulatory requirements.
- The Board approves projects or programmes with expenditure greater than $2.5million.
- The Board reviews monthly performance reports on the status of key work programmes and important network performance metrics. This includes updates on high value and high criticality projects. The Board uses this information to guide management on improvements required, or changes in strategic direction.
- The Board is responsible for overseeing risk management practices. The Board also receives and reviews reports by external auditors.

Executive Team

Like most organisations, support is provided by a group of General Managers each responsible for a functional area of the organisation. The Board's core responsibilities include determining the organisation's strategic direction and focus, and providing advice and counsel to executive leadership. This includes determining the organisation's long term goals and outcomes. The Executive team structure is illustrated by the chart below.

Figure 2.2: Executive Team



The following section outlines the responsibilities of the main business groups, with a focus on their roles within the asset management system.

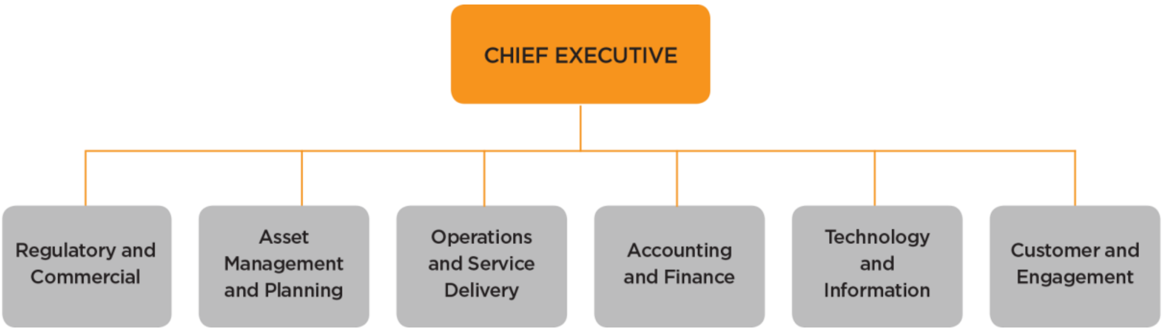
2.1.3. Governance Roles and Responsibilities

Asset management decision-making occurs at a variety of levels, from the Board to field staff. However, the primary responsibility for the asset management of the electricity distribution network lies with the General Manager Asset Management and Planning, and the General Manager Operations and Service Delivery, and their direct reports.

Organisation Structure

Following the separation from Delta our business has been structured into six groups as depicted below.

Figure 2.3: Organisation structure



The following sections provide an overview of the roles and responsibilities of the main business groups.

Asset Management and Planning

The Asset Management and Planning group is responsible for ensuring the electricity network meets customer requirements for reliable and safe energy delivery, is practical to operate, and is technically efficient. This includes maintaining current and accurate information about the performance of the network and its assets. An important aspect is monitoring technological and demand trends, assessing their potential impact, and devising strategies to deal with them in the network development plan.

This group has recently been restructured[17] and now consists of four specialist functions focussed on key asset management activities. The following table sets out these teams and their responsibilities.

Table 2.1: Asset Management and Planning Teams

TEAMS	KEY RESPONSIBILITIES INCLUDE:
Network Planning	Load forecasting Network HV power flow model maintenance Fault studies and LV network modelling Major project and reinforcement planning Replacement configuration Property and asset relocation planning Transpower planning interface Contingency planning
Fleet Management	Prepare plans/scopes aligned to asset lifecycle strategies Monitoring and interpreting asset condition Risk assessment Identifying assets for intervention Scope asset intervention ready for implementation Developing asset maintenance and replacement plans Asset specialist support to design teams
Engineering Design	Technical support to projects Lead design standards Design for customer works and major projects (where applicable) Protection modelling in network model New equipment assessment Safety in design Technical specifications Assist scopes for planning and replacement where appropriate
Strategy and Reliability Performance	Asset management Strategy Lead asset management development plan Lead network reliability / performance forecast Security of supply guide Asset lifecycle strategies HV/LV architectures Collaborate on comms architecture Demand-side management and emerging technology strategy Coordinates AMP prep and AMMAT reviews

17 This restructure will support our efforts to improve our overall asset management capacity and capability.

Operations and Service Delivery

The Operations and Service Delivery group is responsible for ensuring the 24/7 real-time, safe, reliable and resilient operation of our networks. In addition, it manages the delivery of field activities (e.g. maintenance) and our capital works programmes. An important aspect of this is managing relationships with field service contractors, and monitoring deliverables to achieve safety, operational and financial targets.

If supply is interrupted unexpectedly, we respond by restoring it as quickly and safely as possible. Our operations staff are in constant contact with field staff when supply needs to be restored. We collect information to help us reduce the risk of future outages. This includes recording what caused the power cut, what areas were affected, and for how long. This supports network asset management by providing information to support root cause analysis and renewals planning.

This group's accountabilities are scheduled to be reviewed[18] to enable an increased focus on managing external service providers, and streamlining works delivery and scheduling. The following table sets out the potential functions and accountabilities for the operations and service delivery team.

Table 2.2: Operations and service delivery functions

FUNCTIONS	ACCOUNTABILITIES
Operate network	Operational risks Network faults Monitor service performance Network access Dispatch field work Incidents and events
Provision of network services	Service delivery strategy Procure major plant and equipment Negotiate contracts Manage contract performance Prepare and evaluate tenders
Manage works programme	Manage work programme Manage and report project expenditure Scope work packages Manage projects

Technology and Information

The Technology and Information group is responsible for providing and operating required information communications and technology efficiently. It supports network asset management by providing current and accurate information about the extent and performance of the network and assets.

The group is responsible for monitoring technology, customer and industry trends, assessing the effectiveness of new technologies, and determining the optimum time to implement those best suited

18 We plan to undertake an assessment of the resource capability and capacity needs of the wider Operations and Service Delivery team by the end of November.

to meet business and customer needs. This includes ensuring technology and information plans provide effective direction to network performance and asset management planning and delivery.

The group provides cyber security capability to safeguard corporate and network systems. We discuss our approach to managing our ICT assets in Section 7.3 and Appendix E.

Regulatory and Commercial

The Regulatory and Commercial group maintains our relationships with major connected customers and retailers, as well as other interested parties, such as distributed generators. The team is responsible for managing commercial agreements. It collects data associated with consumer connections to the network, and provides advance information on customers' growth intentions to support effective planning. The group ensures that pricing strategy and the associated pricing methodology is fit-for-purpose, and that pricing outputs are compliant and generally fair.

The group also monitors the development of regulation, preparing appropriate submissions to regulatory consultations, and conducting appropriate analysis to ensure that the impact and risk of regulatory change is understood. This includes developing and deploying regulatory control processes and procedures across the business to ensure regulatory compliance.

Accounting and Finance

The Accounting and Finance group is responsible for co-ordinating financial planning and performance reporting, cash management, and treasury arrangements to ensure financial resources are available and utilised effectively. The group maintains internal control procedures to achieve efficiency objectives, timely and accurate financial reporting, and legislative, regulatory and taxation compliance.

The group provides strategic and financial planning support to the CEO and executive leadership team and is working to develop risk and assurance reporting frameworks across the business. Non-network expenditure in respect of premises, vehicles, plant, and travel are also managed by this group.

Customer and Engagement

The to-be established Customer and Engagement group will be responsible for managing stakeholder and customer interfaces within the organisation and reflecting these interfaces in stakeholder engagement plans. This group will ensure that stakeholders, including the community and customers, have opportunities to provide feedback and input into future network investment plans. The information we provide is informed by relevant, quality information about the operation, performance and future development of the network.

The group will also be responsible for developing, designing and implementing people-related frameworks, policies and practices to attract, align, develop, engage and retain quality people to deliver business goals and help facilitate the development of desired organisational culture.

Partnering with senior managers, the group will drive cyclical activities for workforce planning, development planning, performance management, remuneration and rewards, talent management, succession planning, and measuring employee engagement. This extends to providing advice, guidance and coaching to managers and staff in relation to people-related matters, ensuring consistency of policy application and legal compliance.

2.2. OUR STAKEHOLDERS

A key objective of our AMP is effective consultation with our stakeholders. As well as using it to drive our own decision-making, it explains how we manage our assets. Our aim is that our AMP should provide enough detail to explain our plans and decisions in a way that enables others to understand the drivers for our expenditure. This includes explaining how we have prioritised certain work and why. We also aim to make it a document that customers can easily follow.

We recognise that a key asset management function is to understand who our stakeholders are, what they value and why. We define stakeholders as groups or individuals with either a direct or indirect interest in our asset management approach and decisions. Our key stakeholders include:

- electricity consumers
- land-owners and communities hosting our assets
- Transpower, electricity retailers and distributed generators
- our regulators: the Commerce Commission, Electricity Authority, and WorkSafe
- government agencies
- property developers
- territorial authorities
- our staff
- contractors and service providers
- shareholders and the Board
- media.

Chapter 4 explains how we accommodate these stakeholder interests in our asset management framework and investment decisions. If a conflict between stakeholder interests is identified, then we will seek to resolve it to both address the issue and any stakeholder concerns. Ultimately, our Board decides the most appropriate way to resolve any significant conflict between stakeholder interests. We maintain alignment with the Utility Disputes Commissioner scheme requirements.

Below we provide further context on some of our key stakeholders.

2.2.1. Electricity Consumers

Electricity consumers are our primary focus. We identify their needs through surveys, feedback, and direct interaction. While there may be diverse levels of service sought by some groups, our current understanding is that all customers tend to be concerned with four main aspects of our service: safety; quality of supply; cost of the service they receive; and the level of customer service we provide. We seek to manage these aspects within our asset management system by specifying appropriate technical and performance standards.

2.2.2. Communities

We have a responsibility to the wider communities in which we operate and their needs are an important focus for us. Using a number of channels we are working hard to develop a better understanding of the communities' needs and concerns, which we believe centre on safety, the impact of our assets on the environment, and network resilience. These issues are important to us and are reflected in our approach to managing our assets and planning future investment. Our objectives and approach to public safety, environmental issues and resilience are described in Chapter 4.

2.2.3. Retailers

We frequently communicate with retailers through our operational, billing and payment interactions, and regular consultation. We understand retailers' requirements of us as an electricity distributor. These requirements include: the delivery of effective business-to-business services; use of transparent, simple and appropriate network tariff structures and prices; and fair contractual arrangements. We view retailers as customers in their own right and representatives of end-consumers.

The retail market is undergoing considerable change. We expect retail competition to intensify, become more sophisticated, and require further segmentation. These changes will likely occur during the coming AMP planning period.

Working with retailers to ensure a simple and effective energy supply for customers is a key part of what we do. We also ensure that retailers understand the impact of their business approach on our operations. An example would be the retailers' approach to accommodating technologies such as solar and electric vehicles (EVs), which may impact our network and require changes to our pricing approach or demand forecasting methodology.

2.2.4. Regulators

As an electricity distribution business, our operations are subject to regulations established under various Acts and Regulations, including the Commerce Act and the Electricity Industry Participation Code. The rules are primarily administered by the Commerce Commission and the Electricity Authority.

The Commerce Commission is our economic regulator and manages regulations around price-quality performance and disclosure of relevant information (Information Disclosure). The Electricity Authority is responsible for regulating an efficient electricity market and other related aspects of an electricity distribution business, such as pricing structure and commercial agreements with retailers.

WorkSafe is responsible for regulating workplace safety and electrical safety.

2.2.5. Transpower

We receive our electricity supply via Transpower, New Zealand's transmission company, via five grid exit points (GXPs) located across our network areas. Transpower also holds the role of system operator giving it responsibility for, amongst other things, maintaining the integrity of the electricity system including the coordination of electricity generation and demand.

We consult with Transpower on our respective investment plans, commercial relationships, and other industry issues. We have established systems and protocols with the system operator to facilitate immediate communications for operational issues and incidents.

2.2.6. Service Providers

Service providers[19] are essential to our ability to supply electricity distribution services to customers. Accordingly, we are focused on ensuring they perform and deliver the services required of them in an effective and efficient manner. They, in turn, require our interactions with them to be predictable, transparent, and commercially sound.

To achieve stable, efficient use of resources we review and refine our forward workplan. This enables our service providers to be effectively and efficiently deployed. This is a key part of managing work deliverability.

2.2.7. Our Staff

Our staff are the driving force behind our business. Our staff value job satisfaction, a safe and enjoyable working environment, and being fairly remunerated for the work they perform.

As we develop our asset management approaches, we are placing increased emphasis on effective internal communication and staff engagement in delivering asset management requirements. These requirements will be expanded as we progress our internal competency framework.

We strive to be a good employer and have incorporated health and safety policies and initiatives, performance reviews, and forward work planning so that staff can maintain a work/life balance.

2.2.8. Other Stakeholders

We provide services to a range of other stakeholders. These include the New Zealand Transport Agency and territorial local authorities that frequently require us to move our lines or cables for road projects. House relocation organisations may also require us to switch off our lines during their operations. Developers require us to provide connection services to housing developments.

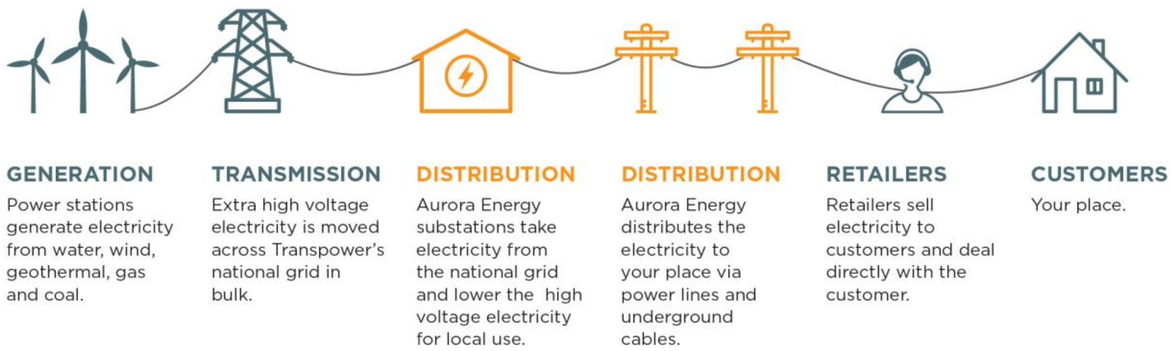
2.3. CUSTOMERS

We distribute electricity (see Figure 2.4) to close to 90,000 homes, schools, farms and businesses in Dunedin, Central Otago and Queenstown Lakes, supporting economic and social activity across these regions. As use and dependence on electricity has grown, so too have customers' expectations of the availability and quality of their supply. In addition to excellent customer service, customers increasingly expect good, timely information about their service. It is important we fully understand the services customers require, and what value they place on these, now and into the future.

Like most electricity distributors we operate an interposed model. This means retailers purchase our services, bundle them with energy supply and the cost of accessing the transmission grid, and provide a bundled price for delivered energy to their customers. Currently 19 retailers sell electricity to end-consumers on our network. Generally, retailers are responsible for collecting revenue on our behalf and maintaining direct contractual relationships with end-consumers.

[19] We have recently engaged two additional service providers, Unison Contracting and Connetics.

Figure 2.4: Our role in the electricity sector



2.3.1. Residential and Small Commercial

This segment includes residential customers and small to medium enterprises. The majority of our connections (approximately 99%) fall into this category. These customers typically buy bundled energy supply services directly from retailers and may not be fully aware of our role within the electricity industry. This is a situation we are actively trying to improve, for example, by publishing community updates on our website.[20]

Service expectations will vary, depending on where customers live (rural or urban) or their recent experiences of reliability. We find that most customers can accept occasional power cuts, and that our ability to keep them informed during these events is most important to them. Ensuring reliable, effective information flow to customers is a priority.

Growth in our mass market consumer base is closely tied to population and is regionally diverse across our footprint. Our Central Otago network continues to grow, supported by inward migration to the region alongside increasing tourism activity and economic prosperity. On the other hand, ICP numbers on our Dunedin network are stable.

Over the past three years, growth in customer numbers means we need to continually refine our forecast load estimates and increase network capacity. Our customer connection teams and processes have been bolstered to ensure we meet this growing need and continue to provide good customer service. Our approach to connecting new customers to our network is discussed in Chapter 6.

2.3.2. Major Customers

Our major customers are from the dairy, food processing, transport, manufacturing, tourism and university sectors. Growth in this category is closely tied to general economic growth (indicated by GDP), for example the tourism sector continues to add large facilities (e.g. ski-fields).

Open dialogue with major customers is important to ensure we understand their businesses so we can better meet their supply requirements. We engage directly with them on their future investment plans, since increases in their capacity needs can have implications for our network development investments.

[20] See http://www.auroraenergy.co.nz/about/community-updates

Our growth and security investments during this planning period, discussed in Chapter 6, have been informed by such discussions.

Due to the size and complexity of their operations, our large customers often have more specific service requirements than residential customers. The timing of outages and degree of notice provided (in the case of planned outages) can have significant operational and financial impacts on these customers.

Chapter 3 provides further detail on the main customers on our Central Otago and Dunedin networks.

2.3.3. What Customers Care About

As discussed above, we have a diverse customer base, comprising residential, commercial and industrial customers across a large area of the South Island. What each customer values differs. To better understand what customer groups value, we engage with them to capture their preferences. Based on these engagements, we know that customers care about:

- a safe network: delivering electricity safely to customers is our core business and we know how important this is to customers and other stakeholders.
- reliability: based on feedback we have received, a reliable electricity supply is very important to consumers. Residential consumers care more about how long the power is out than how often it's out. They care more about power outages in winter and/or evenings. Outages during business operating hours are of most concern to business customers.
- value for money: while the industry structure can mean customers often do not associate their monthly bill with the cost of providing a safe and reliable service, we know they are conscious of cost increases for what is an essential service.
- good communications: customers value timely and accurate information about their supply, including information on planned outages. This has been driven, in part, by advances in mobile technology and social media that have created an expectation that information should be readily available through a number of channels. Customers are more understanding about not receiving direct communication when the power goes out due to circumstances beyond our control. Information regarding planned outages is critical to business customers due to the potential financial losses associated with outages during their operating hours.
- responsiveness: responding quickly to issues on the network is key to reducing their impact and lessening potential safety and reliability risks. This is achieved through coordinated activity by our network operations teams and our service providers.

The above views inform our approaches to managing our assets and our investment decision-making.

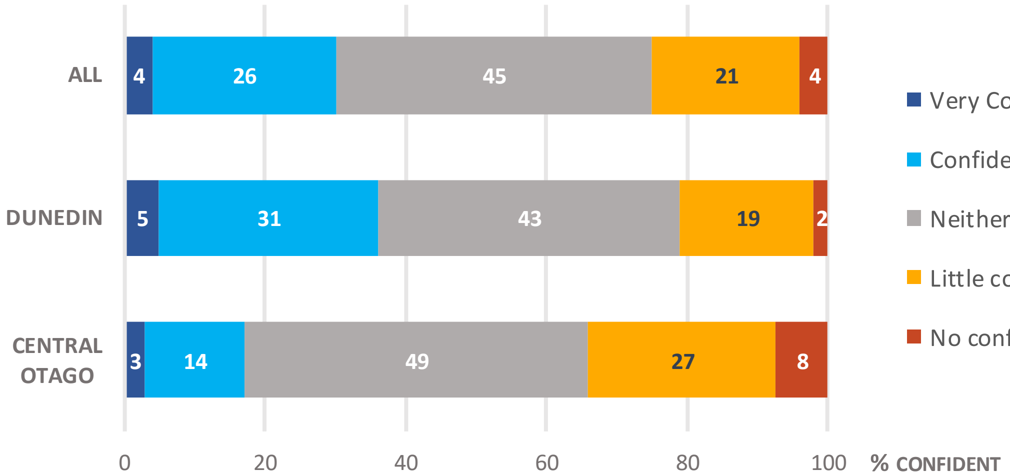
2.3.4. Our Performance

We have carried out regular telephone surveys of a sample of residential and small business customers since 2006. The results of our 2017 survey[21] has been supported by market research undertaken in 2018. Findings include the following:

- customers prefer to maintain the status quo in terms of the frequency of interruptions, if this means that prices remain the same
- the majority of customers who had experienced an unplanned interruption in the previous six months considered that restoration had occurred within an acceptable time frame
- customers have low levels of awareness of the names of their lines company
- in general, customers do not know what proportion of their electricity bill pays for electricity distribution
- almost all customers who had been notified of a planned interruption in the previous six months were satisfied with the amount of information provided and the period of notice
- the majority of customers who experienced an unplanned interruption and contacted us were satisfied with the communications they received
- the majority of customers who contacted us about matters other than planned outages were satisfied with the handling of their enquiry, which is a significant improvement from previous survey results.

These findings are broadly consistent with similar surveys undertaken in previous years.

Figure 2.5: Customer feedback on whether Aurora Energy is 'heading in the right direction'



We are conscious of the proportion of customers who are unsure or who are not confident that we are heading in the right direction. Through our customer engagement initiatives, we expect to significantly improve these results in the lead-up to our CPP submission in May 2020.

[21] The survey took place in October and November 2017.

Customer Service Initiatives

We are meeting the needs of customers on a number of metrics, but there is room for improvement in others. In particular, we are seeking to improve our engagement and communication with customers, and to streamline the processes we use to connect customers to our networks (see Box 2.1).

We have published a Customer Charter on our website setting out our commitments to our customers, including safety, customer feedback, complaints resolution, responsiveness, and quality of service.[22]

Box 2.1: Customer Service Initiatives

We have developed initiatives to improve the effectiveness of our customer engagement:

- community updates
- customer voice panels
- engagement on key focus areas, e.g. outputs of the independent risk review by WSP
- improvements to our customer initiated works processes
- public safety campaign/communications
- improved outage notification.

In August 2018, we published the first of a series of community updates to provide information to stakeholders on who we are and what we do, setting out recent activity, and explaining our future investment plans. Over time, we plan to publish a series of substantive updates on our network and its performance. These regular, open engagements will help stakeholders provide input into our future plans and performance objectives. We will publish details of these consultations on our website.

We have also established a customer voice panel, comprising local electricity consumers. The panel's objectives are to improve our understanding of customer needs and expectations and to keep customers updated on what they are interested in using the communication channels they prefer.

We have an ongoing campaign to increase public awareness of electricity network hazards and to engage the community in understanding electricity safety. Through these interactions we have looked to deepen our understanding of public safety risk factors. The campaign includes public safety advertising focused on specific audiences, and communications on preparing for power outages.

We have made a number of improvements in our outage notification procedures. We notify customers of planned outages via electricity retailers (and advertising in the case of major outages), and provide media with safety advice prior to forecasted severe weather events where there is a higher likelihood of network damage and power outages.

Further improvements include publishing planned outage information on our website and in regional newspapers, developing a social media presence with outage information and safety tips, contacting medically dependent electricity consumers and businesses prior to planned outages, and establishing a dedicated customer support function. We plan to further enhance our communications, including providing real-time updates during major storm events.

We have begun a process to improve our approach to facilitating customers connections. We use the term customer-initiated works (CIW) to describe works requested by individual customers and which require liaison with connecting parties, developers and their service providers. We are assessing ways

22 Customer Charter – Our commitment to you, Aurora Energy, Jan 2018.

to streamline our current processes to ensure customers receive a prompt and efficient service through using an optimal mix of internal resource and external specialists. Where appropriate, the use of external resources for CIW design and construction management will reduce internal workload and enable a greater focus on design standards and asset management maturity to support the efficient delivery of our wider works programme.

In the coming months we will begin engaging with customers on the results of the independent review (discussed in Section 2.4.1). We will then build on these engagements to form focus groups to provide feedback on how best to seek and incorporate views on our CPP proposal.

This AMP is a further opportunity for stakeholders to let us know how we are doing. We welcome feedback on the plans set out in this AMP or any concerns our stakeholders may have.

2.4. OVERALL CONTEXT FOR OUR 2018 AMP

The period since we published our previous AMP has seen a number of changes across our business. This section sets out an overview of these changes and how they have they impacted our approach to asset management.

2.4.1. Independent Review

Earlier this year (May 2018), we appointed an independent engineering firm[23] to review the current state of our network. This comprehensive assessment of our network assets seeks to provide a common understanding of the current state of our electricity network, including underlying asset condition and risks. The findings will be shared with customers, regulators, local councils, and the communities that host our assets.

The main aims of the review are to confirm the current condition of our network assets and to determine the resulting reliability and safety risks. The review, and our response, has had a consumer focus in respect of public safety, reliability, and environmental risk.

The reviewer has completed an initial desktop review of our asset information and, at the time of writing, is close to completing a detailed assessment of our assets, including physical inspections and sample testing in the field.

WSP provided us and the Commerce Commission with interim feedback at the end of August 2018, which included emerging views on a number of assets fleets. Broadly, the emerging views from the independent review confirm the practices we are already working to embed.

WSP's interim findings support our plans to improve and expand condition investigations for conductors and pole tops/cross-arms. As part of facilitating the independent testing, we are progressing a range of condition assessment techniques that will enable us to better determine conductor and pole top/cross-arm condition.

23 The independent reviewer is WSP, one of the world's leading professional engineering consulting firms, operating as WSP Opus in New Zealand.

The interim findings, and our discussions with WSP, have prompted us to review a number of areas in our AMP investment plan.[24] For example we have:

- increased the volumes of crossarms to be replaced during the planning period
- bolstered our secondary systems replacement plans to ensure that all electromechanical and solid state relays are replaced within the AMP period
- included an upgrade of our battery systems to achieve greater DC systems reliability
- reprioritised our zone substation switchgear replacement programme.

The final review report will be available later this year. We will then consider its findings in detail as we prepare our March 2019 AMP. In the interim, we will further adjust our investment plans if any significant risks are raised in the final report.

We believe the review has been valuable in guiding our response to the challenges we face managing and operating an ageing network. It is also timely given our intention to undertake a major renewal programme over the next decade. We expect the insights from the review will support our short-term priority investment areas, and that the findings will help inform our future investment plans.

2.4.2. Pole Programme

In November 2016, we instigated a fast track pole programme focused on the renewal of at-risk poles. The trigger for this initiative was the need to address a backlog of work and to mobilise a company-wide effort to ensure at-risk poles were removed from the network. This programme instigated a number of process improvements that have been embedded under our new operating model. These changes include delivery improvements that decoupled civil and electrical works and the use of pole reinforcement techniques to accelerate risk-reduction and reduce programme costs.

The programme has now been completed, significantly reducing the backlog of at-risk poles and reducing overall risk on the network. Since the fast track pole programme we have continued to refine the management of our pole fleet, including researching new testing methodologies such as forensic pole testing, and targeting high criticality areas for pole testing and replacement.

When managing safety risks, the condition and design of our overhead assets in public places is critical. This is driving our efforts to improve the condition of our pole fleet and the data and processes that facilitate prudent interventions.

As discussed in this AMP, our pole replacement programme needs to continue to focus on the remaining backlog. We anticipate that another two years of elevated pole testing and pole replacement is required before replacements are reduced to a longer-term, steady-state level.

Chapter 5 provides further detail on our approach to managing our pole assets.

2.4.3. Introducing Contestability

Our planned work programme includes significantly higher levels of capital investments and field activities compared to historical levels. The increased use of competitive tendering and the introduction of two additional service providers will lower the risk of under-delivery and help ensure we receive

[24] The changes refer to our initial 2018 AMP forecasts, and not those published in previous versions of our AMPs.

efficient and market-tested pricing. In August 2018, we concluded a process to introduce new contracting arrangements and establish contracts with the new providers.

This process clearly set out the expectations we have of our service providers. These requirements will be expanded as we progress our competency framework and extend these to external parties working on our network.

2.4.4. Asset Management Development Plan

Building on our most recent self-assessment of asset management maturity (AMMAT), and inputs from stakeholders, we have begun a process to improve our asset management processes and capabilities. We recognise that there is a number of areas that should be improved.

Over the planning period, we will focus on improving staff competency, developing fit-for-purpose systems, and adopting proven innovations. This includes an overhaul of our asset health modelling and the introduction of a network-wide criticality framework. Both of these initiatives will enable targeted interventions and will better inform our renewal forecasts over the planning period.

We have updated and revised our AMMAT assessment following a robust review of current capability, informed by comparisons with peer utilities. The resulting lower score better reflects our current capability and a need to improve our asset management processes. We want to be open and transparent about our current capability and plan to put in place a series of initiatives to lift our maturity over the next few years. This work will inform a refined asset management development plan (AMDP).

Our ultimate aim is to ensure our asset management is consistent with leading New Zealand practice within five years. We plan to use asset management certification (specifically ISO 55000[25]) to monitor and demonstrate our progress to stakeholders.

Chapter 7 provides further detail on our AMDP.

2.4.5. We have made changes to our management team

Effective leadership is important in any business experiencing significant change. In addition to appointing new Directors, we have made significant changes to our management team since publishing our 2017 AMP. Those most directly relevant to the development of our 2018 AMP are:

- Dr Richard Fletcher was appointed as our CEO in January 2018. He brings extensive international experience in engineering and management consulting across the electricity, gas, and water sectors. He has advised on energy regulation, asset management, due diligence studies for mergers and acquisitions, as well as engineering investment plans. Before joining Aurora Energy, Richard was General Manager Regulation and Corporate Affairs at Powerco and prior to that a senior manager at Transpower.
- Glenn Coates, previously with Orion, was appointed as our new General Manager Asset Management and Planning. He brings 29 years of experience in the electricity industry and strengths in asset management strategy, network planning, demand side management, and future networks.

[25] ISO 55000 is an internationally recognised asset management standard that has been adopted by a number of New Zealand and overseas utilities.

These two appointments see experienced executives from large EDBs joining our leadership team to help lead our management thinking. Both have been closely involved in CPP submissions driven by a need for increased renewal investment.

2.5. Operational Context

This section provides an overview of the issues that impact our approach to asset management. The wider environment we operate in is an important factor in how we deliver our services. There is a range of factors that determine the operational environment. These include climate, access to third party land, and vegetation near our assets. The sections below discuss each environmental factor.

2.5.1. Climate

Prevailing weather, particularly extreme conditions (e.g. wind or snow storms), can have a significant impact on the condition and reliability of our assets.

Central Otago has a continental climate with hot summers, cold winters, and low humidity. These conditions are relatively benign for metallic assets (e.g. conductors), with low levels of corrosion compared with the maritime climate in Dunedin.

Weather-related events contribute to the incidence of interruptions to our customers, particularly in rural areas. This is due to the presence of overhead lines and outdoor assets, which are subject to interference from vegetation and windblown debris, and failure during weather events.

The Cromwell, Alexandra and Roxburgh areas have very low relative average rainfall, but the availability of water in the region's lakes makes irrigation a viable option for agriculture. This demand for irrigation drives investment in additional capacity.

2.5.2. Land Access

Our ability to gain access to existing assets or obtain land for new assets is critical to timely and effective asset interventions. We have been granted certain rights under the Electricity Act for assets built prior to 1992 to remain where they are currently located. We are also entitled to access road reserves under the relevant council's conditions.

We acquire easements when installing new assets on private property to formalise the respective party's legal rights. Obtaining the rights is usually straightforward when a private land owner will directly benefit from providing access, as in the case of a new connection. However, obtaining access for new assets to transit private land is often challenging and can impact our project planning. As such, we begin work to obtain the necessary land access rights as soon as practical in the planning process. We aim to minimise (as far as practical) the amount of land access required, as changes in access requirements can cause additional expense and delay in delivering new assets.

2.5.3. Vegetation

Vegetation located close to our assets has the potential to interfere with their safe and reliable operation. We manage vegetation in accordance with the requirements of the Electricity (Hazards from Trees) Regulations 2003. We do this by patrolling, monitoring, and recording sites where vegetation could interfere with the safe and reliable supply to our customers. We trim, spray, or remove vegetation accordingly. Vegetation management is discussed further in Chapter 5.

2.6. REGULATORY CONTEXT

Electricity distribution businesses such as Aurora Energy operate within a regulatory framework administered by the Commerce Commission. The framework specifies the level of revenue we can recover, and sets out minimum quality standards in terms of supply interruptions.[26]

Our planned investment path has moved significantly beyond the allowances set under the default price-quality path (DPP) that the Commission established in November 2014. The levels of allowed revenue and our quality standards cannot accommodate our current and planned renewal work programmes, which require increased investment and extensive planned outages. This means that a proportion of the investment we are now making will never be recovered or reflected in our prices, and we will earn lower returns than the Commission generally considers reasonable. There is also an increased likelihood we will breach our quality standards due to the required level of planned outages. We expect this to remain the case for the coming two years and under a new DPP to apply from 1 April 2020.

In contrast to previous practice, we are now taking a long-term view of network and customer needs rather than constraining our forecasts within regulatory allowances. The level of investment we have begun to make, and will continue to make over the next decade, is a significant increase on historical levels and we expect this to remain above future allowances to be determined by the Commission in its DPP reset.

We will submit a customised price-quality path (CPP) application to the Commission in May 2020 and transition to this mechanism in April 2021.[27] A CPP will better support the demands of renewing the network in the coming years. A CPP is necessary if we are to deliver a safe and reliable service to customers over the long term. It will fund the required future investment in the network and address the impact of increased planned outages during the rebuild phase.

As part of our process to develop a CPP application, we will undertake a series of detailed consultations with customers. This will seek their views on price-quality preferences, network resilience, and future technology expectations. Consultation will be supported by engagement on the findings of the independent review (see Section 2.3.4).

The CPP process provides a mechanism for the our sector regulator, the Commerce Commission, and stakeholders to review and have a say on our proposed investment, and the potential impact on consumer pricing, before we finalise our investment plans.

Our CPP timeline means we will retain current DPP expenditure allowances for at least the next two years. However, we will maintain our increased levels of investment despite the significant financial consequences for spending above our allowance. To ensure our business's sustainability, we will need a bespoke allowance, established under a CPP, if we are to fund further future investment.

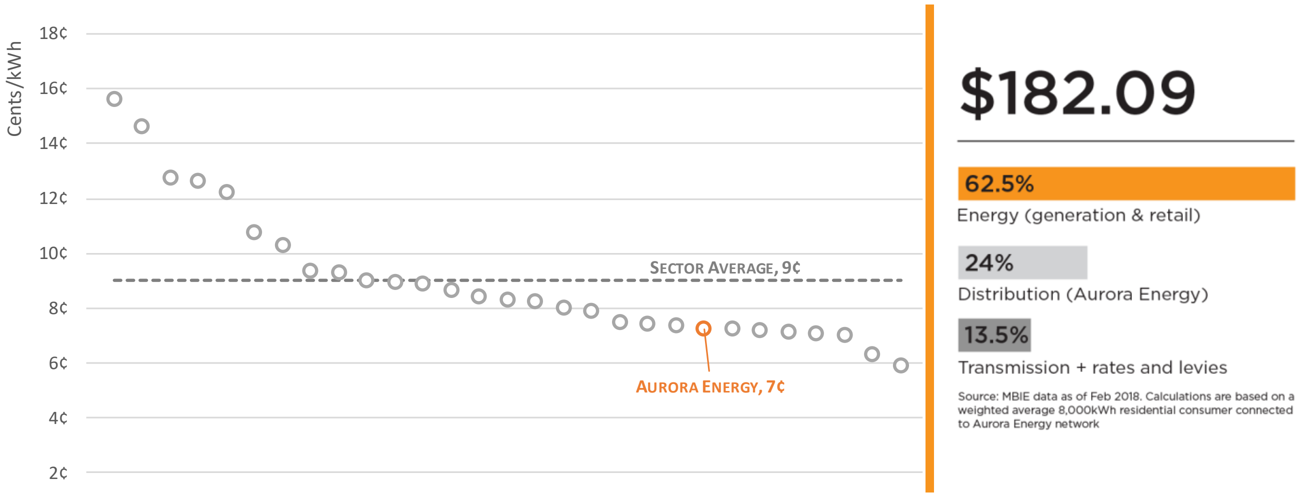
[26] Some consumer-owned EDBs are subject to a more limited regime based around Information Disclosure.

[27] A CPP is a regulatory mechanism that the Commission can use to establish a price-quality path that better suits a company's individual circumstances.

2.6.1. Potential Impact on Pricing

Our planned investment programme will mean that prices will need to increase but we are working hard to minimise this cost impact on customers. As noted above, our prices under a CPP will not be reset until 1 April 2021 and these will need to be reviewed and approved by the Commerce Commission. While any price increase is unwelcome, our network prices have not increased for an extended period and benchmark low against the rest of the sector (see Figure 2.6).

Figure 2.6: Revenue benchmarking[28] and the Aurora Energy portion of a typical electricity bill)



[28] Source: EDB Information Disclosures 2017.

3. NETWORK OVERVIEW

This chapter briefly describes our networks in Dunedin and Central Otago and sets out related statistics.

3.1. BACKGROUND

We own and operate two non-contiguous electricity distribution networks in Dunedin and Central Otago. These networks include all the power lines, poles, underground cables, substations and transformers that take electricity from the national grid to the homes, farms and businesses we supply.

Figure 3.1: Aurora Energy network with major towns and cities

Like many other networks in New Zealand, much of our electricity infrastructure was first built in the 1950s and 1960s. As a result large portions of our network are now due to be renewed. Over the next ten years, we plan to make significant investments to maintain and renew our distribution network.

Our two regional networks include five subtransmission networks, with each network being named after the GXP supplying it.

- Halfway Bush
- South Dunedin
- Frankton
- Cromwell
- Clyde

The two oldest networks – Halfway Bush and South Dunedin – are in Dunedin. The development of these networks started around 1910, although there were pockets of electricity supply before that.

The three Central Otago networks – Frankton, Cromwell and Clyde – were mostly developed after 1960, although these also include pockets of older assets. Some of these networks were originally 6.6 kV, but apart from a small portion around Clyde, they have all been converted to 11 kV.

Equipment condition varies across the five networks. The Central Otago networks are generally in better condition than the Dunedin networks, mainly due to the younger age of the equipment.

Our Dunedin and Central Otago networks supply close to 55,500 and 34,000 customers, respectively. Both networks include a number of major and smaller industrial and commercial connections. In Dunedin these mostly relate to the city infrastructure, including the port, university, and local council operations. Large consumers on our Central Otago network include tourism, irrigation and council loads.

A small embedded network connected to The Power Company network was installed in Te Anau in 2005 and supplies over 100 customer connections.

Total energy throughput for the year ending 30 September 2017 was 1,399 GWh (including distributed generation). This is 46 GWh (3.4%) higher than the previous year, as the 2016 winter was very mild. The increase is mainly attributable to more typical winter temperatures in 2017. Overall energy growth on our network has been mixed over the past five years, averaging 1.2% per annum.

3.2. NETWORK CONFIGURATION

Our network is hierarchical in nature, with lines and cables operating at three distinct voltage ranges:

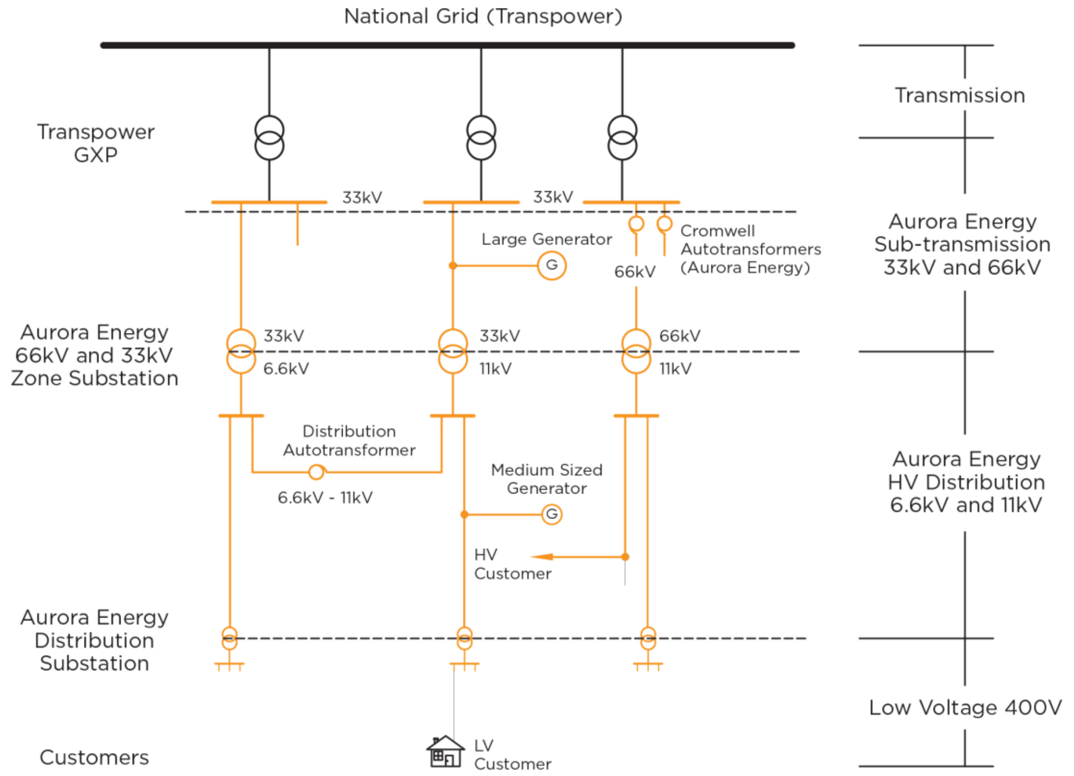
- **Subtransmission:** operating at 66 kV (minority) and 33 kV
- **Distribution:** generally operating at 11 kV in Central Otago and 6.6 kV in Dunedin
- **Low Voltage (LV):** operating at 400 V three phase or 230 V single phase.

Electricity from higher voltage circuits (lines and cables) is transformed, at numerous substations, to supply lower voltage circuits. Generally, the voltage conversion is from 33 kV to 11 kV, then to the 400/230 V supplied to homes and businesses. We use subtransmission at 66 kV where there are long distances between GXPs and zone substations, as this reduces line losses incurred. In Wanaka and the surrounding area, the first conversion is from 66 kV to 11 kV. The Dunedin distribution network is typically 6.6 kV, which reflects the age of the networks, with 6.6 kV the international standard distribution voltage prior to 1970, and 11 kV becoming standard from the 1960s. Each of our LV circuits serves between one and a few hundred customers.

The Dunedin distribution and low voltage networks largely consist of overhead lines, with 317 of the 1,047 kilometres of distribution network and 385 of the 1,650 kilometres of the LV network being underground. In Central Otago, 724 kilometres of the 2,297 kilometres of distribution circuit and 757 of the 1,053 kilometres of LV circuit are underground.

Figure 3.2 provides an example single line diagram illustrating the various voltages through which power is supplied and transformed from the National Grid to end consumers.

Figure 3.2: Representative Single Line Diagram

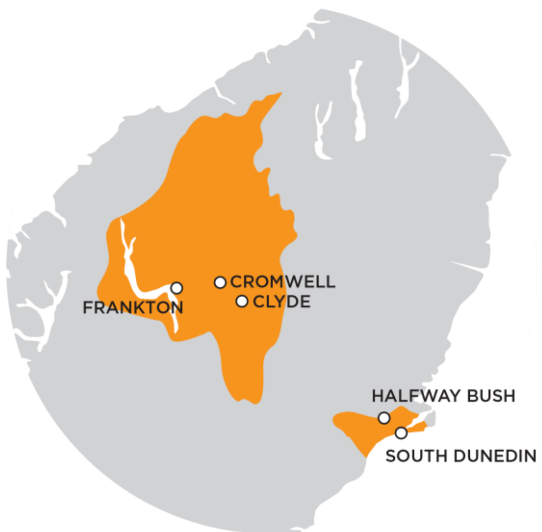


Zone substations convert high voltage electricity to lower voltages for supply to customers over a wide area. Distribution transformers then lower the voltage further for local distribution at the street level.

3.3. GRID EXIT POINTS

We receive electrical energy from Transpower's network at five points of supply, known as grid exit points (GXPs). These are Halfway Bush, South Dunedin, Frankton, Cromwell, and Clyde. These points are the interface between Transpower's transmission network and our distribution network.

Figure 3.3: Aurora Energy network areas and Transpower GXPs



We deliver electricity from GXPs, through our networks, to close to 90,000 homes and businesses in Dunedin and Central Otago.

Our subtransmission overhead lines and underground cables each carry a large amount of electricity from Transpower's GXPs. A GXP failure could result in loss of supply to a large number of customers, so a highly reliable configuration is required. There is redundancy built into GXPs through duplication, so that the system can continue to function using an alternate path (N-1) in the event of a failure.

GXPs are owned by Transpower, although we have some equipment co-located at some of these sites (structures, cables and air break switches at the South Dunedin and Frankton GXPs). Each GXP supplies a specific zone or area (subtransmission network), with limited or no connectivity between the zones.

Table 3.1: GXP area statistics

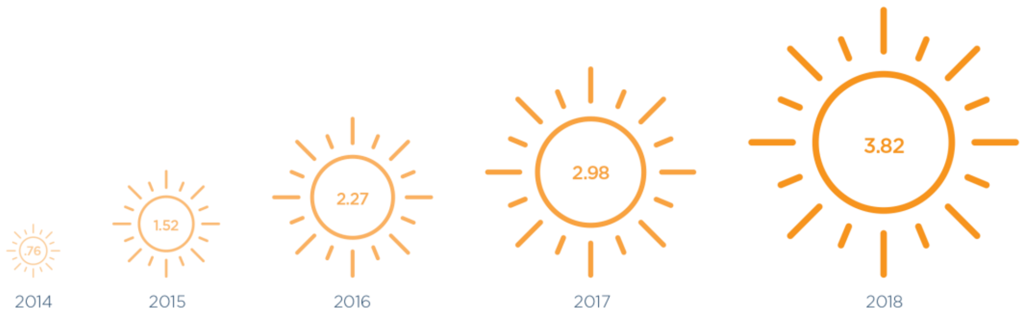
	HALFWAY BUSH	SOUTH DUNEDIN	FRANKTON	CROMWELL	CLYDE
Number of customers	38,000	17,500	13,600	13,100	7,250
2017 Load (MVA)[29]	128.1	70.6	61.3	36.7	19.5
Number of transformers	25	10	13	8	7
Transformer capacity (MVA)	392	218	154	88.5	43
Outgoing circuits	19	10	7	4	2

3.4. DISTRIBUTED GENERATION

Distributed generation schemes have the potential to make a significant contribution to future network development, in terms of security, efficiency and economy of network operation. However, distributed generation can also produce adverse effects on the network, including harmonic distortion, localised congestion, voltage instability, safety issues and network reliability issues. Accordingly, care is required when approving new distributed generation connections.

The level of small-scale distributed generation within our network is low at present, but is expected to continue to grow during the AMP period. We expect that most new distributed generation connections will continue to be photovoltaic (PV) installations – these generate electricity during sunlight hours but will not materially impact peak demand during winter evenings.

Figure 3.4: Total installed solar capacity (MW) on Aurora Energy network



29 2017 calendar year winter loadings.

Expected PV installations do not have a material influence on the network design and investment at this time but may drive the need for further network investment towards the end of the AMP period.

Guidelines and application information for the connection of distributed generation are published on our website: www.auroraenergy.co.nz. For each proposal we consider the likely effect of the distributed generation on our network.

We have developed a standard distributed generation Use of System agreement as a basis for commercial negotiations. The standard agreement was developed with reference to relevant regulations and appropriate conditions in retail Use-of-System agreements. We consider that this approach maintains a degree of industry consistency and standardisation.

Commercial arrangements for distributed generation vary. For small distributed generation (generally below 10 kW), the default arrangements specified within Part 6 of the Electricity Industry Participation Code normally suffice. The commercial arrangements for larger generation warrant greater attention due to the greater use of and impact on system assets.

There is currently 130 MW of distributed generation connected to our network, across 904 connections. Hydro and wind generation remain the predominant forms of distributed generation, contributing 63% and 29% (respectively) of total distributed generation capacity. Small-scale photovoltaic generation comprises 97% of generation connections, but makes up only 2.8% of capacity. Table 3.2 sets out all distributed generation connections 1 MW or greater.

Table 3.2: Distributed generation (1MW or greater)

NAME	TYPE	CAPACITY (MW)
Waipori 33 kV, Waipori gen & Deepstream 1A, 2A	Hydro	53
Waipori 33 kV - Mahinerangi	Wind	36
Teviot stations	Hydro	12.3
Horseshoe Bend	Hydro	4.3
Horseshoe Bend Wind	Wind	2.3
Fraser Generation	Hydro	3
Meg	Hydro	4.3
Wye Creek	Hydro	1.7
Ravensdown Generation	Process steam	3
Talla Burn	Hydro	2.2
Container Port (Port Otago)	Liquid fuel	1.6
DCC Waste water treatment plant	Biomass	1

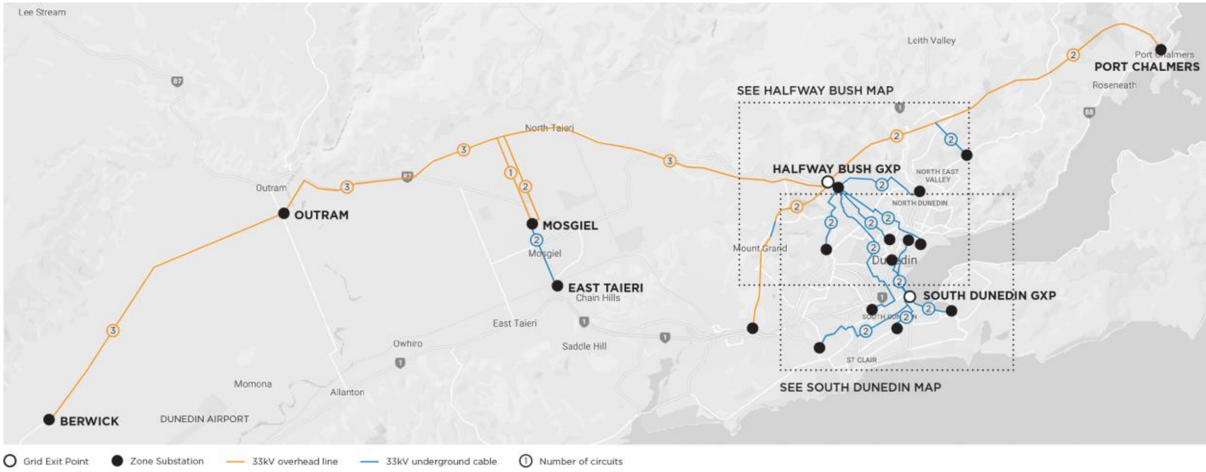
Distributed generation connections have been increasing at more than 25% per annum, the vast majority of these being small PV connections. Ongoing growth will be highly dependent on the cost of PV panels, and could also be impacted significantly by future changes in government policy in this area. Due to the size of PV connections, we do not expect continuing growth to have a material network impact, but we will continue to consider the cumulative impacts over time, particularly if evidence of generation clusters emerges.

We have received an application for an additional 8 MW of hydro generation from Pioneer Energy at Earnscleugh Station. This is being worked through and we expect it to be operational within the next two years. In addition, two 0.5 MW diesel generation connections (for backup supply) at Otago University are expected to be operational within the next year.

3.5. DUNEDIN NETWORK

Until the 1970s, Dunedin was supplied entirely from the Halfway Bush GXP. Construction of the South Dunedin GXP resulted in the network supply points from some zone substations being altered. The additional GXP provides added resilience for the city's supply.

Figure 3.5: Dunedin subtransmission networks



The urban subtransmission system in Dunedin is a radial system, where the 33 kV supply is distributed out from a single point. As a radial network, redundancy in supply to each zone substation is achieved by installing two underground cables in close proximity to one another. Redundancy minimises the impact of a failure of supply to a zone substation. The existing network configuration does not give us options to transfer significant load between GXPs.

The 33 kV underground cables installed in Dunedin vary in age and construction. The older cable construction in Dunedin uses high pressure gas insulation. Excavating around this type of cable requires significant care due to the pressure the cable maintains within its sheath. We also have several other types of cable, as described in Chapter 5.

3.5.1. Dunedin Load

The Dunedin area load is a mixture of residential, commercial and industrial. Due to the climate, residential and commercial heating contribute significantly to the network peak load, which follows an expected pattern of morning and early evening peaks. These peaks are greater on colder winter days. Load control (predominately of domestic hot water storage systems) is used to reduce these peaks.

In the Dunedin area, we have experienced a small decline in demand in recent years. This is partly due to economic conditions, compounded by a series of mild winters, increased efficiency in utilisation (e.g.

heat pumps and more efficient lighting) and a gradual uptake of edge technologies (such as electric vehicles). We expect that electric vehicle load will start to reverse this decline in load over the planning period, but we do not anticipate demand will exceed historical highs over that time. As a result, investment in Dunedin will primarily be driven by the need to replace ageing assets and maintain existing levels of reliability.

Table 3.3: Dunedin load and customer statistics

GXP	Approximate Number of Customers	RY17 (MVA)
Halfway Bush	38,000	128.1
South Dunedin	17,500	70.6
Total customers	**55,500**	
Coincident demand		**195**

A small amount of dairy farming on the Taieri Plains gives rise to irrigation and milking loads during summer, especially on the Berwick zone substation.

3.5.2. Major Customers

Below we discuss key customers on the network and how we manage and operate our assets to ensure they receive required levels of service.

Dunedin City Council

The combined load of all the Dunedin City Council operated sites is significant. The most important sites are those associated with water and waste water pumping and treatment. Long-term failure of supply to these sites can cause significant social and environmental impacts. The larger, more critical sites have alternative feeds from multiple zone substations, and the Council has installed backup generation at critical sites. These sites would become a priority for restoration of supply for any natural disaster, most likely in co-operation with Civil Defence.

Dunedin Hospital

The Dunedin Hospital is a significant and critical load which is supplied via two feeders from North City zone substation. An internally operated changeover arrangement enables switching of supply between these feeders and/or backup generators as required. An alternative direct feed from the Ward Street zone substation is available should both North City feeders fail.

Construction of the new Dunedin hospital in the near future may require the relocation of the North City substation and installation of a new supply to manage the expected increased load. Given the uncertainty around the project we have not made provision for the relocation in our forecasts.

University of Otago

The University of Otago operates a number of buildings in the northern part of Dunedin City. University load – and load from surrounding student-occupied accommodation – reduces over the university holiday periods.

Originally, the University was fed from a private HV network fed from North City zone substation. However, the University has grown over time to encompass additional buildings, a number of which are connected to other feeders. The addition of load and alternative feed arrangements into the North City feeders has complicated our protection, and we have elected to run the main university bus open. There are a number of alternate feed possibilities into the University area from the Ward Street, Willowbank and Smith Street zone substations.

Port Otago

Port Otago is also a sizable customer, and the port is a critical business for the Otago area. If the port were not able to operate for any reason, this would have significant financial and social implications for the city and the region. In addition, power outages are extremely undesirable due to the business's need to turn around shipping traffic in a timely manner. Electricity is also required for refrigerated containers at the port, to protect perishable goods.

Port Otago is fed via two separate feeders from the Port Chalmers zone substation, with a manual changeover arrangement. The port operates some standby generation, mainly for refrigeration. The port will be a critical facility should any significant natural disaster event occur in the southern part of the South Island. It will likely be a key facility for transportation of emergency equipment and supplies.

Dunedin Airport

Loss of supply to the Dunedin Airport has both commercial and air traffic safety implications. The airport operates a standby generator and has an auto-changeover system that switches between a feeder from the Outram zone substation and a feeder from the Berwick zone substation. As with the port, the airport will likely become a key facility in times of natural disaster.

3.5.3. Halfway Bush Network

Our overhead subtransmission system in Dunedin consists of seven 33 kV radial lines originating at the Halfway Bush GXP. These feed mainly rural areas, although some significant urban areas – Mosgiel, East Taieri, North East Valley and Port Chalmers – are also supplied via these lines. Throughout the overhead 33 kV lines, small sections of underground 33 kV cable – known as siphons – are installed where it was not practical to retain overhead lines, generally because of development.

The subtransmission system from Halfway Bush supplies approximately 38,000 customers.

The Halfway Bush GXP feeds the following zone substations.

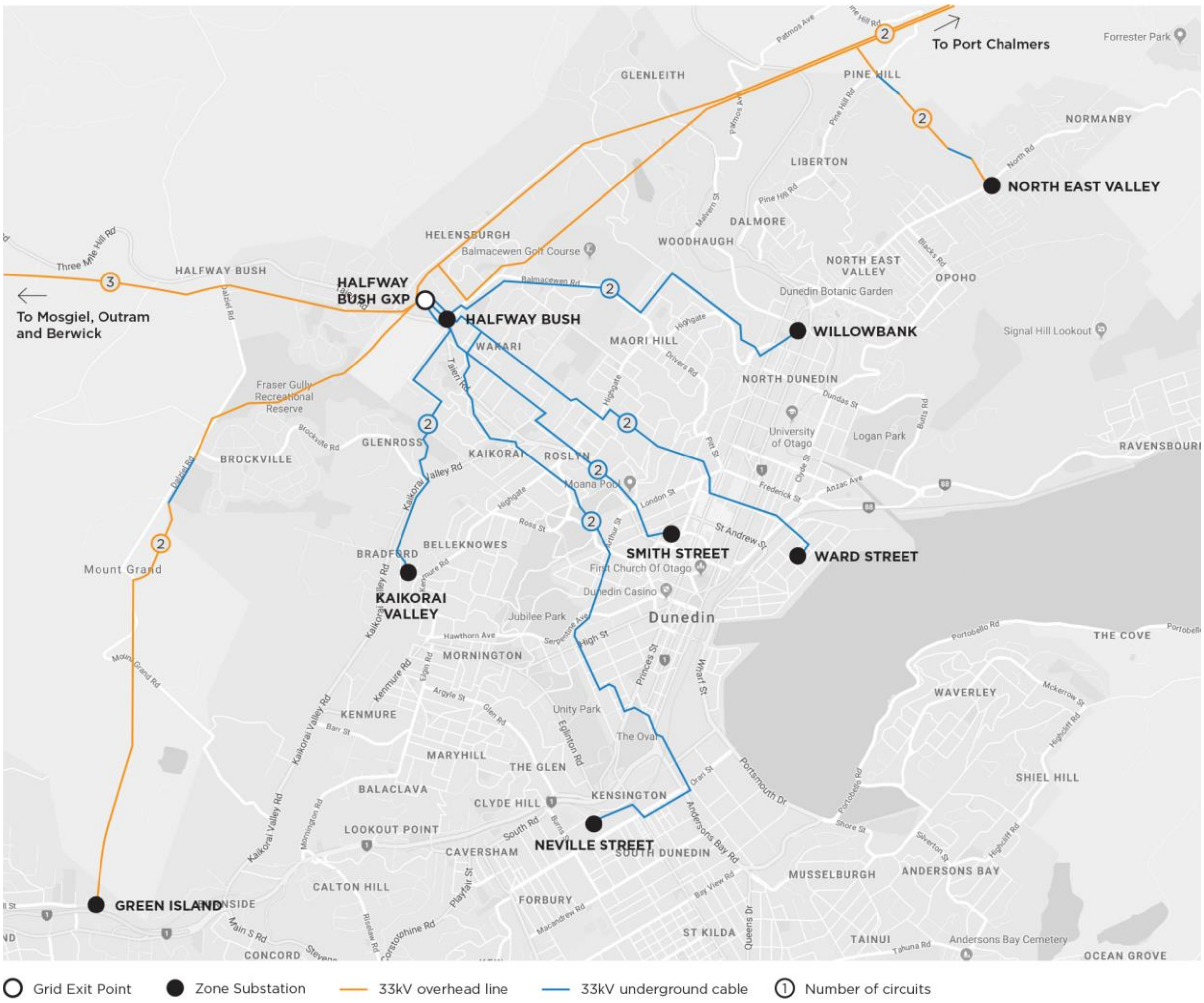
Table 3.4: Halfway Bush zone substations

Zone Substation	Feeder Type	Transformer[30] (MVA)	Peak Load 2017 (MVA)
Berwick (not shown)	Overhead line	3/3.6	1.4
East Taieri (not shown)	Overhead line	12/24 and 12/24	16
Green Island	Cable	15/18 and 15/18	13.3

[30] Dual rated transformers are denoted with X/Y ratings where 'X' is the base rating and 'Y' is a rating that is achievable through the operation of cooling fans and/or pumping oil through the tank and cooling fins.

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER[30] (MVA)	PEAK LOAD 2017 (MVA)
Halfway Bush	Cable	24 and 24	14.5
Kaikorai Valley	Cable	12/24 and 12/24	10.2
Mosgiel (not shown)	Overhead line	10/12 and 10/12	6.9
Neville Street[31]	Cable	15/18 and 15/18	11.6
North East Valley	Cable/Overhead line	9/18 and 12/24	10.8
Outram (not shown)	Overhead line	3/3.6	2.8
Port Chalmers (not shown)	Overhead line	7.5/10 and 7.5/10	6.5
Smith Street	Cable	15/18 and 15/18	14
Ward Street	Cable	12/24 and 12/24	10.7
Willowbank	Cable	15/18 and 15/18	12.6

Figure 3.6: Halfway Bush network

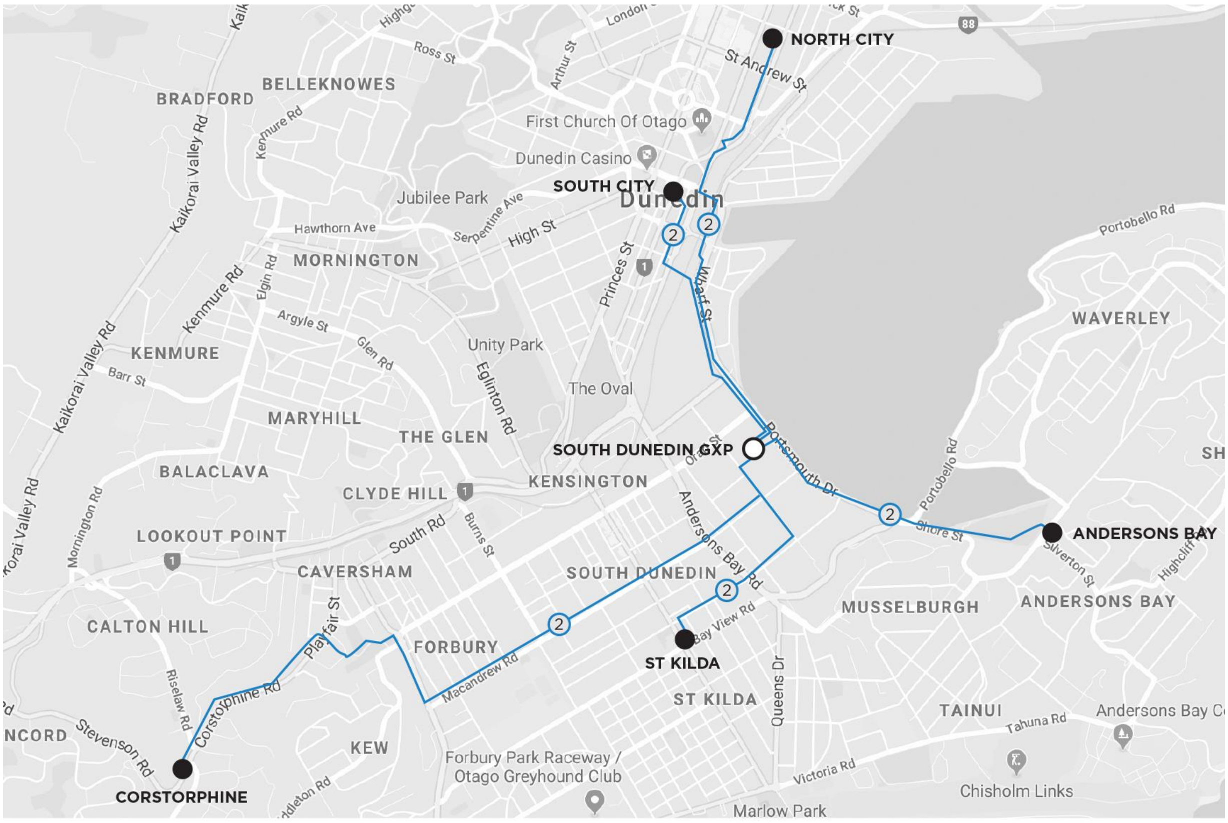


[31] Neville Street is being replaced by Carisbrook and will be decommissioned by January 2019

3.5.4. South Dunedin Network

The South Dunedin network is fed by a single GXP (South Dunedin). The subtransmission network is fully underground consisting of dual circuit cables feeding six zone substations (following the commissioning of Carisbrook). The subtransmission system supplies approximately 15,500 customers.

Figure 3.7: South Dunedin network



Grid Exit Point | Zone Substation | 33kV underground cable | Number of circuits

The South Dunedin GXP feeds the following zone substations.

Table 3.5: South Dunedin zone substations

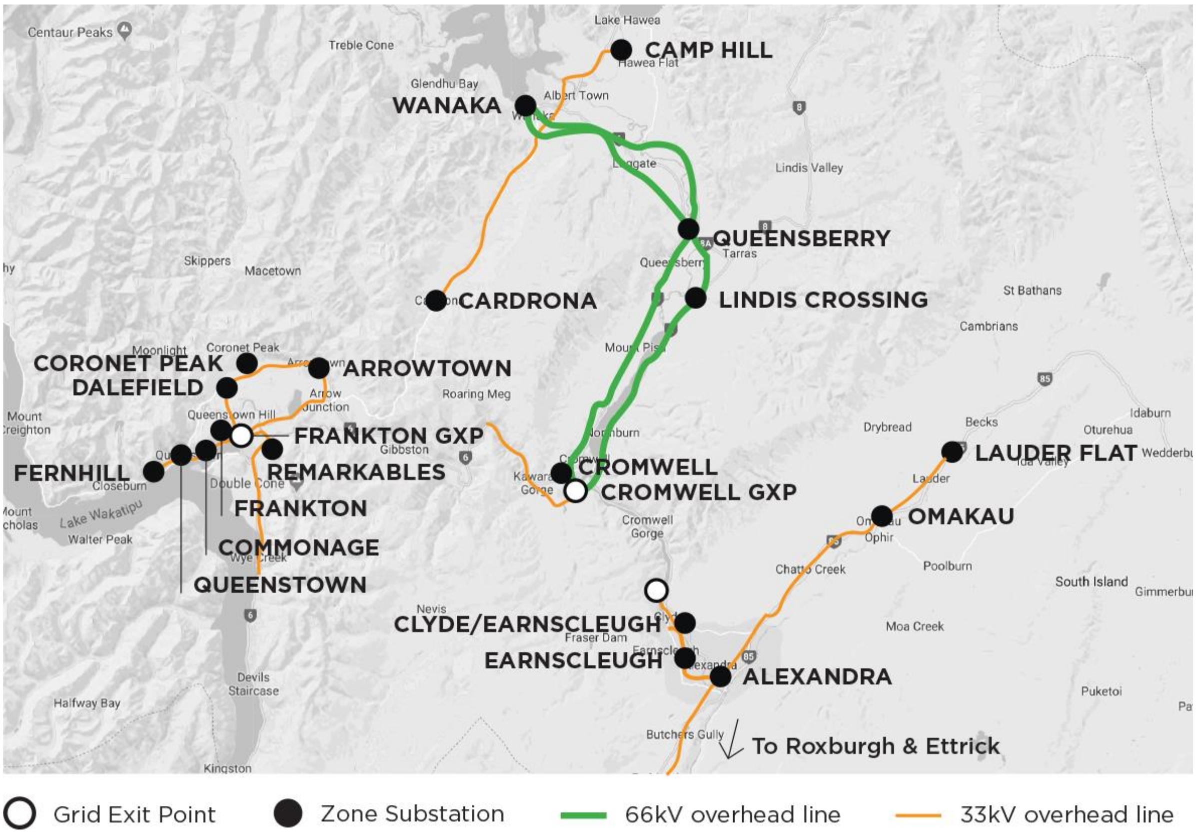
ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2017 (MVA)
Andersons Bay	Cable	15/18 and 15/18	15
Carisbrook[32]	Cable	18/24 and 18/24	Not applicable
Corstorphine	Cable	12/24 and 12/24	12.8
North City	Cable	14/28 and 14/28	18.2
South City	Cable	9/18 and 9/18	15.3
St Kilda	Cable	12/24 and 12/24	14.8

32 Carisbrook will be taking over the Neville Street load and will be fully commissioned by November 2018

3.6. CENTRAL OTAGO OVERVIEW

The Central Otago network is supplied via the Frankton, Cromwell and Clyde GXPs. Each of the GXPs supply a geographically distinct network with little or no interconnection between the networks.

Figure 3.8: Central Otago subtransmission networks



Central Otago is one of the fastest growing regions in New Zealand. The two key growth drivers are agriculture and residential developments. Central Otago has the most extreme climate on mainland New Zealand, which has implications for electricity supply. The climate is characterised by hot summers, cold dry winters, low air humidity and a predominantly dry westerly wind.

3.6.1. Central Otago Load

We have seen steady load growth on the Central Otago network, driven by steady growth in residential subdivisions together with significant one-off projects such as ski field developments. We have also seen extremely high growth in irrigation load in some areas. However, while this has driven a large increase in annual energy consumption and necessitated significant network investment it does not contribute to the GXP peak loads which remain winter peaking.

Due to Central Otago's very dry climate, irrigation has always been important. A number of significant pumping stations have been in service for many years, some of which have legacy agreements for low-cost electricity supply.

Central Otago's ski fields are significant users and can control their own peak load, while some use diesel generation to supplement available supply. Capacity increases generally require a customer contribution and are managed under commercial agreements.

Table 3.6: Central Otago load and customer statistics

GXP	APPROXIMATE NUMBER OF CUSTOMERS	LOAD 2017 (MVA)
Frankton	13,600	61.3
Cromwell	13,100	36.7
Clyde	7,250	19.5
Total customers	**33,950**	
Coincident demand		**115**

3.6.2. Major Customers

This section discusses the key customers connected to our Central Otago network and how we manage and operate our assets to ensure they receive required levels of service.

Ski Fields

The Central Otago ski fields are among our largest customers. Load at these sites includes ski lifts and snow-making machinery, and supply to buildings and associated activities. Ski lift load is relatively consistent on days that the fields are open. Snow-making load occurs mainly on cold mornings early in the winter season but can run all day if natural snow is lacking and conditions are suitable for snow-making. Peak loads generally occur when snow-making overlaps with lift operations.

All ski fields receive supply via single feeders over difficult terrain, with only limited backup. Ski fields are typically open for around 80 days per year, depending on snow conditions. Loss of electricity supply during a busy day – such as during school holidays – would cause significant financial loss. Ski field load outside the ski season is generally very low.

Irrigation

The Central Otago networks have a significant amount of irrigation load (e.g. Dairy Creek Irrigation Scheme). Some of this has been driven by dairy conversions. Irrigation demand is relatively consistent over the summer period but may be delayed by an unusually wet spring. At the end of the season irrigation load may reduce if it becomes too dry and sources of race water become limited. Irrigation load does not generally drive growth investments as it occurs outside of winter peak load periods. However, some zone substations have become summer peaking and required development specifically to supply irrigation load.

The Hawea and Tarras areas have seen a large increase in irrigation demand. In these areas water is often pumped over relatively long distances and/or to relatively significant heights, resulting in high electrical load per irrigated land area. The Omakau area has also seen a significant growth in irrigation, but here the demand per irrigated land area has been significantly lower as the pumping is usually from nearby surface ponds and races.

Local Councils

The combined load of the Central Otago District Council and the Queenstown Lakes District Council sites is significant. As in Dunedin, the most important loads are those associated with water and waste water pumping and treatment. Most of these sites have alternative HV feeds that are manually switched as required. These sites would become a priority for restoration of supply for any natural disaster, in co-operation with Civil Defence if appropriate.

Queenstown Airport

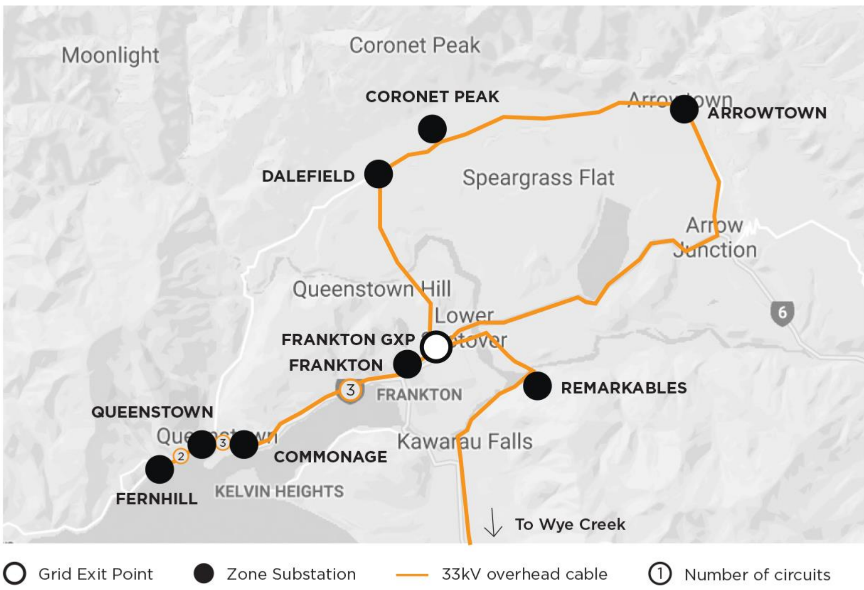
In conjunction with growing tourism in Central Otago, the Queenstown Airport has grown from a small regional airfield to a busy international airport. As in the case of Dunedin's airport there are commercial and air traffic safety implications in the event of loss of supply. The airport operates a standby generator for critical loads and peak demand management. A feeder from Frankton substation supplies the airport. The Frankton area network is meshed and a number of alternative supply options exist in the unlikely event the Frankton substation is out of service, including supply from the Commonage substation.

3.6.3. Frankton Network

The Wakatipu basin is supplied from the Frankton bulk supply point operated by Transpower. There are eight zone substations in the Queenstown, Frankton and Arrowtown areas that transform the voltage from the 33 kV subtransmission voltage to 11 kV distribution. From there, 11 kV circuits distribute power to smaller distribution transformers.

The Frankton, Queenstown, Arrowtown and Dalefield areas are supplied via 33 kV overhead lines from the Frankton GXP. The 33 kV ring is used to feed Arrowtown, Coronet Peak and Dalefield and to provide back-feed capability should one section of the ring fail. It also connects the Wye Creek generation facility. The subtransmission system supplies approximately 13,600 customers.

Figure 3.9: Frankton network



The Frankton GXP supplies the following zone substations.

Table 3.7: Frankton zone substations

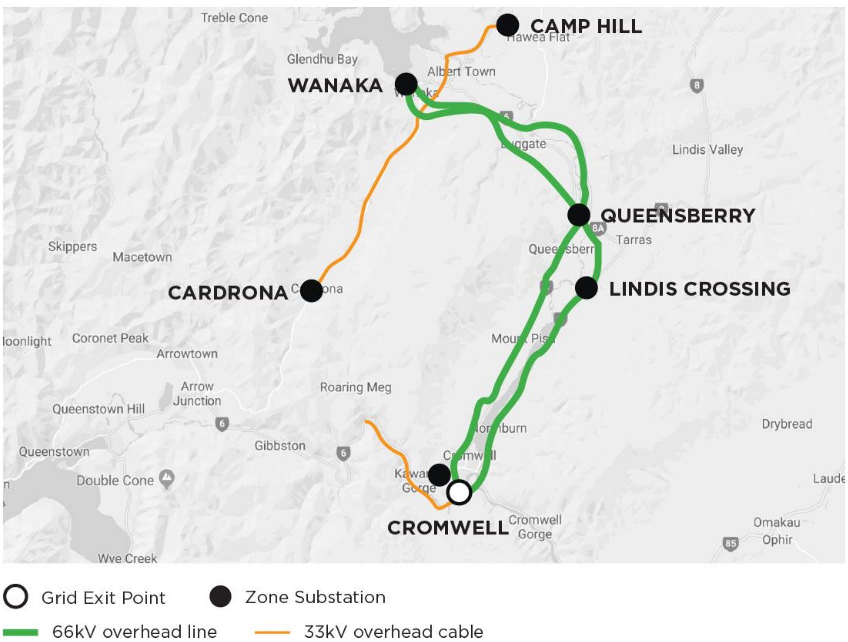
ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2017 (MVA)
Arrowtown	Overhead line	5/6 and 5/6	8.5
Commonage	Overhead line	14/17 and 14/17	12.2
Coronet Peak	Overhead line	5/6	5.3
Dalefield	Overhead line	3/3.6	2.4
Fernhill	Cable	10 and 10	6.7
Frankton	Cable/Overhead line	12/24 and 7.5/15	14.6
Queenstown	Overhead line	10/20 and 10/20	14
Remarkables	Overhead line	3/3.6	2.4

3.6.4. Cromwell Network

The Upper Clutha area is supplied from Transpower's Cromwell GXP. To supply the large electricity demand in the Wanaka, Cardrona and Hawea areas, two 66 kV overhead lines run from Cromwell to Wanaka, one on either side of Lake Dunstan. These lines terminate at the Wanaka zone substation and are each approximately 55 km in length. These are our only 66 kV circuits.

There has been considerable demand growth in this area recently, necessitating the construction of a new substation to be located at the corner of Riverbank Road and Ballantyne Road. Initially this will be a 66 kV switching station, but there is provision to install two transformers on-site. The switching station is expected to be commissioned in late 2018 and will allow us to continue to reliably meet regional electricity growth. This new substation will also enable the Cardrona line to be operated at 66 kV, as constructed, which will improve the efficiency of electricity delivery to Cardrona. The subtransmission system supplies approximately 13,100 customers.

Figure 3.10: Cromwell network



The Cromwell GXP supplies the following zone substations:

Table 3.8: Cromwell zone substations

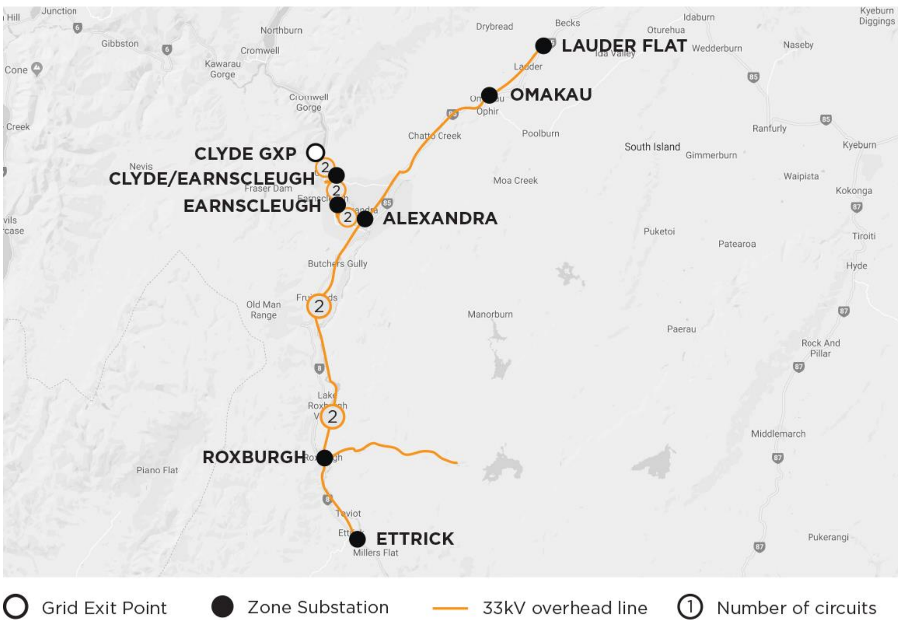
Zone Substation	Feeder Type	Transformer (MVA)	Peak Load 2017 (MVA)
Camp Hill	Overhead line	6.5	5.3
Cardrona	Overhead Line	5/6	4.1
Cromwell	Cable/Overhead line	7.5 and 5/10	11.2
Lindis Crossing	Overhead line	7.5	5.9
Queensberry	Overhead line	3/4	2.8
Riverbank Road	Cable	N/A	TBC
Wanaka	Overhead line	12/24 and 12/24	19.8

At Wanaka zone substation the subtransmission voltage is transformed from 66 kV to 33 kV, and two zone substations in the Cardrona and Hawea area (Cardrona and Camp Hill zone substations) are supplied from here. Approximately 7,800 connections are supplied by these three zone substations. These substations supply the distribution network at 11 kV.

3.6.5. Clyde Network

The Alexandra, Clyde, Manuherikia, Ida Valley and Teviot Valley areas are supplied via two 33 kV subtransmission circuits connected to the Clyde GXP. Most of the demand in the area is supplied from distributed generation sites at Teviot, Ettrick and Earnscleugh. Subtransmission plays an important role in delivering excess generation for injection into the national grid at the Clyde GXP. Two parallel 33 kV lines run between the Clyde GXP and Alexandra, and then onto Roxburgh. Ettrick is supplied by a single 33 kV line from Roxburgh, and Omakau, to the north-east of Alexandra, is supplied by a single 33 kV line from Alexandra. The subtransmission system supplies approximately 7,250 customers.

Figure 3.11: Clyde network



The Clyde GXP supplies the following zone substations.

Table 3.9: Clyde zone substations

ZONE SUBSTATION	FEEDER TYPE	TRANSFORMER (MVA)	PEAK LOAD 2017 (MVA)
Alexandra	Overhead line	7.5/15 and 7.5/15	11.1
Clyde / Earnscleugh	Overhead line	4/4.8	3.1
Ettrick	Overhead line	3/3.6	1.9
Lauder Flat	Overhead line	3/3.6	0.7
Omakau	Overhead line	3	2.8
Roxburgh	Overhead line	5/6	1.8

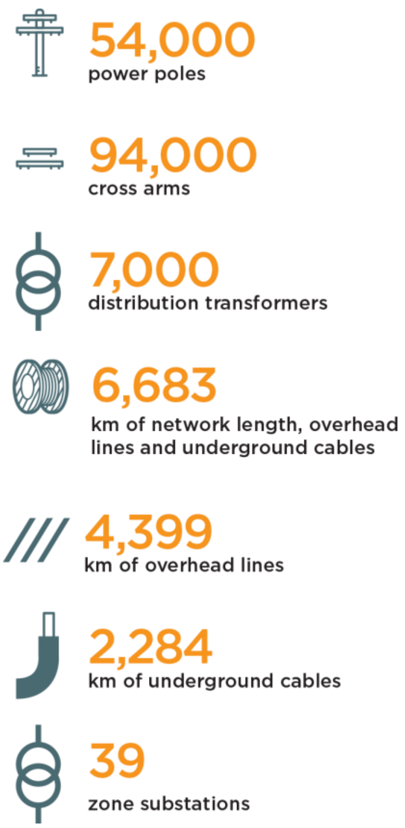
3.7. NETWORK ASSETS

This section provides a high-level overview of the asset fleets that we own and operate, including the overall populations of our key fleets. Further detail on these assets, including their condition and ages, is included in Chapter 5.

The graphic shown to the right illustrates the large number of diverse assets that make up our distribution networks. Each of the categories, in turn, comprises a number of asset types, for example, a crossarm assembly includes not only the crossarm itself, but the insulators and other hardware that sits on the crossarm, enabling it to connect to conductor.

The table below puts a different lens on our assets, comparing the relatively small number of high voltage assets and the large number of distribution and low voltage assets that make up a network.

These views provide an indication of the breadth of knowledge and competency required to plan for, operate, and maintain distribution networks where failure of an asset as small as an insulator can have a significant impact in terms of both safety and reliability.



Grid Exit Points		Zone substations		Distribution transformers		Close to 90,000 customer connections
Halfway Bush	33kV	13	11kV or 6.6kV	2,643	400V or 230V	Dunedin
South Dunedin		5				
Clyde		7		1,464		Central Otago and Wanaka
Cromwell		6		1,648		
Frankton		8		1,245		Queenstown

4. STRATEGY AND GOVERNANCE

This chapter sets out our asset management strategy and explains our overarching governance approaches.

Asset management strategy is the thinking and approach that guide our asset management activities. It sets out how we translate our corporate vision and strategic priorities into asset management objectives that guide our investment and operational decisions. This ensures an effective line-of-sight from our Statement of Intent through our asset management strategies to our daily activities.

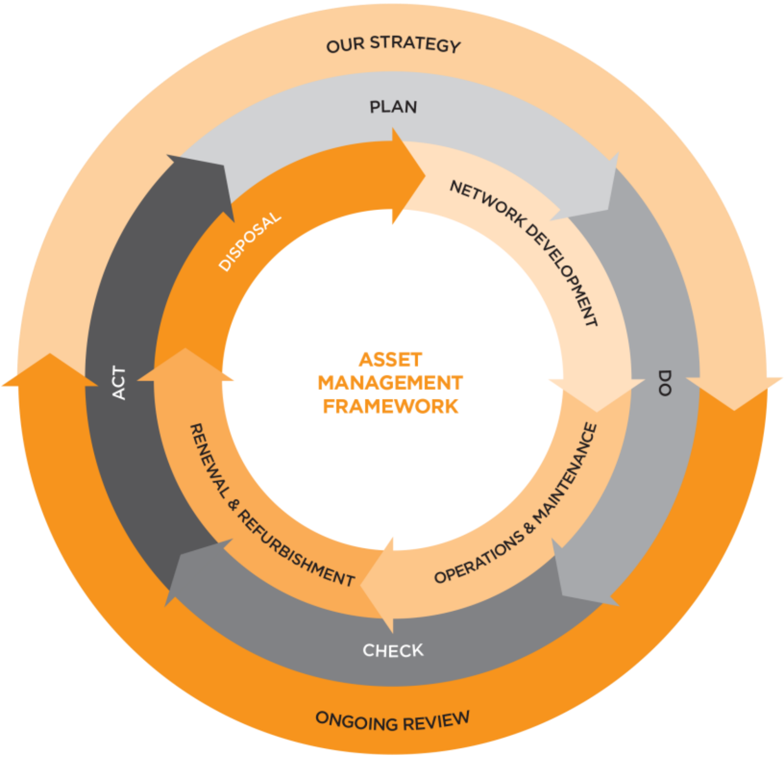
This chapter also presents our asset management governance structures and the responsibilities that support our asset management decision-making. It introduces our approach to asset management decision-making, and explains how we plan and deliver our investments. Effective risk management is a core function of good asset management and our approach is also set out in this chapter.

Finally, it includes an outline of how we plan for resilience against high impact, low probability events.

4.1. ASSET MANAGEMENT FRAMEWORK

The diagram below provides an overview of our asset management framework. It illustrates how strategy informs all stages of the asset lifecycle, and how ongoing and systematic review drives continuous improvement.

Figure 4.1: Asset Management Framework



Our asset management framework is undergoing significant change and development at present. Our asset management improvement initiatives are set out in Chapter 7.

The scope of our asset management framework includes:

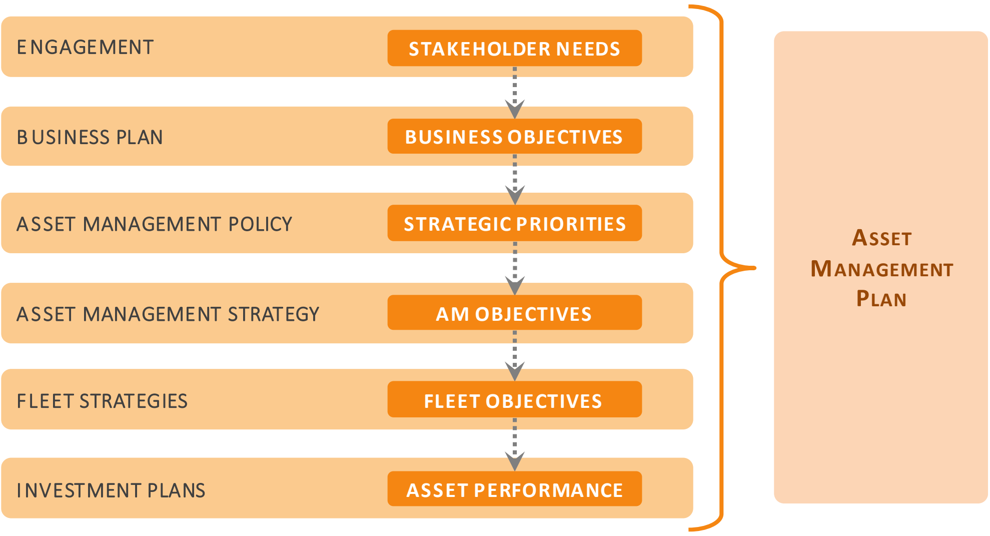
- our people
- network assets
- network operations
- network communications
- warehousing and spares provisioning
- information systems and infrastructure to support asset management
- service provider arrangements for construction and maintenance, including fault response
- procurement of equipment and materials.

4.2. STRATEGIC FRAMEWORK

Our strategic framework seeks to reflect good industry practice by reflecting the views of stakeholders, setting out an asset management policy, and focusing on prudent decision-making through effective corporate governance.

It reflects the thinking and approach that guides our day-to-day asset management activities. It sets out how we translate our corporate vision into our day-to-day investment and operational decisions. This ensures an effective line-of-sight from stakeholder needs, through our strategies to our daily activities. Our AMP summarises our strategic framework as illustrated in the figure below.

Figure 4.2: Strategic Framework



Each of the above elements has a defined ownership (e.g. the AMP is the responsibility of the GM Asset Management and Planning) and each has control and review processes to ensure consistency with our values, vision and mission. The documents are managed through our document management system and by defining required reviewers and level of sign-off (e.g. our Asset Management Policy is reviewed and approved by our CEO).

The main documents in the framework are as follows:

- **Stakeholders**: a large number of internal and external parties have an active interest in how our assets are managed. Ensuring we effectively identify and address these interests is a key focus of our asset management approach.
- **Business Plan**: to encapsulate our corporate vision, purpose and values, and company objectives.[33]
- **Asset Management Policy**: aligns our asset management approach with our corporate objectives through a set of network management strategic priorities.
- **Asset Management Plan**: (this document) sets out our asset management objectives that guide our asset management approach and investment plans over the AMP period. Our asset management objectives reflect our Asset Management Policy by prioritising safety, stakeholder needs and the importance of effective risk management.
- **Fleet Strategies**: (in development) will reflect our asset lifecycle model and set out how these processes and activities are applied to individual asset fleets. They explain how we apply our objectives to individual asset fleets and how these inform our intervention plans.
- **Investment Plans**: are used to manage and deliver our investments and activities.

Ensuring that the above documents and plans support and relate to one another is an important aspect of our asset management system. One of the objectives of our AMP is to ensure these are appropriately summarised for external stakeholders. It is also a key internal document.

The main elements are described in more detail in the following sections.

4.3. Stakeholder Interests

Chapter 2 sets out our key stakeholders. Our asset management approach recognises the diverse interests of our stakeholders, as shown in Table 4.1.

Table 4.1: Stakeholder Interests

Stakeholder	Main Interest	How Interests are Identified
Electricity consumers	Reasonable prices Information on faults Timely response to outages /complaints Safe and reliable supply of electricity Resilience of the network	Consumer satisfaction surveys Direct liaison Customer voice panels Safety campaigns
Government / Regulator	Long term best interests of consumers Economic efficiency Compliance with statutory requirements Accurate and timely information	Submissions Relationship meetings Workshops and conferences
Landowners and communities who host our assets	Safety Easement conditions Appropriate access arrangements	Direct communication Periodic consultation

33 We are close to completing an Aurora-Energy specific business plan, following the separation from Delta.

STAKEHOLDER	MAIN INTEREST	HOW INTERESTS ARE IDENTIFIED
Electricity retailers and distributed generators	Line charges Reliability of supply Contractual arrangements How we manage customer complaints Ease of doing business with us	Use-of-System Agreements Relationship meetings Feedback on AMPs
Property developers	New-connection policies and costs Timely network expansion	Direct communication
Service Providers	Safe working environment Maintenance and design standards Maintaining good contractual relationships Clear forward view of work	Contractual requirements Discussions with field staff Quality documentation feedback
Territorial authorities and NZ Transport Agency	Public safety Minimising environmental impacts Support for economic growth Control of assets in road reserve	Direct communication Submissions RMA applications
Transpower	Effective working relationship Reliability of supply Investment for growth	Direct communication System operator communication
Media	News, background information	Direct communication
Shareholder and the Board	Prudent risk management Compliance Strong governance Return on investment	Board meetings Shareholder briefings

We accommodate these stakeholder interests in our asset management practices through:

- safety plans
- network growth and development plans
- implementation of security standards reflecting customers' needs and expectations
- comprehensive asset replacement strategies
- optimising capital and operational expenditures
- developing solutions to address the worst performing areas of the network
- addressing quality of supply issues in a timely manner
- provision of meaningful, accurate and timely information
- compliance with regulatory and legal frameworks
- audit programmes
- continuously striving to improve the quality of our service.

In a number of cases these are a work in progress.

4.4. CORPORATE STRATEGY

The core function of our business is to deliver electricity safely, reliably and affordably to our customers, now and into the future. Our corporate objectives focus on improving the delivery of this core function.

We have adopted five strategic priority areas as the foundations for improvement. The five areas are:

- Build a high performance safety culture
- Deliver demonstrably optimised business performance
- Deliver excellence in asset lifecycle management
- Deliver value to our customers – now and in the future
- Create a high performing and respected Aurora Energy team

The table below provides strategic goals for each of the five pillars.

Table 4.2: Our five strategic priorities

STRATEGIC PRIORITY	DESCRIPTION
Build a high performance safety culture	Drive cultural transformation throughout Aurora Energy to reposition our safety leadership and performance to a leading industry position
Deliver demonstrably optimised business performance	Optimise key elements of business performance through process and capability improvements to deliver demonstrably efficient outcomes and predictable cost and profitability
Deliver excellence in asset lifecycle management	Reposition our asset management approach to ensure that our network meets customer price and performance expectations while maintaining shareholder value and regulatory compliance
Deliver value to our customers – now and in the future	Achieve proactive and meaningful engagement with our customers and stakeholders to meet their long term needs supported by transparent and streamlined processes
Create a high performing and respected Aurora Energy team	Drive a positive and agile culture where individuals are engaged and teams collaborate to deliver business outcomes

These five strategic goals drive our asset management policy and objectives, as set out in the following sections.

4.4.1. Vision, Mission and Values

Our AMP seeks to explain how our corporate vision and mission inform our asset management approaches and how these reflect the interests of stakeholders. Our vision, as a regional EDB, reflects the importance of serving the communities of Dunedin, Central Otago, and Queenstown.

Box 4.1: 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.

Our mission below reflects our core purpose as an EDB, which is to deliver electricity safely, reliably and affordably to our customers.

Box 4.2: Our mission is to..

Deliver electricity to our communities when and where it is needed, safely, reliably and efficiently.

Our values (below) will be important if we are to achieve our vision and mission.

- **We put safety first**
- **We are solutions focused**
- **We are one team**
- **We pursue learning & innovation**
- **We act with integrity**

Our values were developed for our people, by our people.

They are the key mind sets and standards of behaviour that guide how we work with each other and with our stakeholders.

By living these values every day we will create a work environment that brings out the best in everyone.

4.5. ASSET MANAGEMENT POLICY

Our Asset Management Policy sets out high level asset management principles that reflect our vision and values. It highlights our Board's expectations for the way we will manage our assets and make our decisions.

The policy has been developed to ensure we continually focus on delivering the services our customers want in a sustainable manner that balances risk and long-term costs.

Our Asset Management Policy states that when managing our assets we will:

- provide a safe working environment, and take all practical steps to protect people affected by our assets and activities
- deliver excellent customer service by providing an enduring network that meets customers' long-term expectations
- manage asset lifecycles to deliver the performance expected of the network, taking into account the trade-offs required between performance, cost and risk
- make asset management decisions based on complete, accurate and timely information
- invest in the right mix of talented, competent and motivated people to improve our asset management capability
- build effective relationships with all stakeholders affected by our asset-related activities
- comply with all applicable statutory and regulatory requirements
- seek continuous improvement in our asset management activities
- seek independent certification of our asset management system against ISO 55000.

4.6. ASSET MANAGEMENT OBJECTIVES AND STRATEGY

Our asset management objectives and strategy set the direction for managing our network. They have been developed to achieve the following aims:

- document how our organisational objectives are converted into asset management objectives
- define the role of the asset management system in supporting achievement of the asset management objectives
- provide context for the internal and external issues that may affect our ability to achieve the intended asset management outcomes
- ensure we have the right frameworks, skills, technical capability systems and processes to efficiently and effectively deliver our strategy and optimise asset investments
- drive our continuous improvement programme.

To ensure consistent alignment in our asset management activities we have defined five enduring objective areas that link our corporate strategic priorities (pillars) to our asset management and asset fleet objectives. The table below sets out these asset management objective areas, together with a high level summary objective.

Table 4.3: Asset Management Objective Areas

OBJECTIVE AREA	DESCRIPTION
Health and Safety	Safeguard the public and ensure an injury free workplace.
Customers	Understand the diverse needs of our customers, and provide service levels that will meet their needs on a sustainable basis, taking into account the trade-offs between performance, risk and cost.
Community and Stakeholders	Maintain effective relationships with communities and landowners, to ensure that we can continue to access and maintain our assets.
Service Performance	Deliver a cost effective and sustainable level of asset and network performance.
Asset Management Capability	Develop our skills, knowledge, risk-management competencies, systems and tools to ensure we achieve our health and safety, customer, community and stakeholder, and network service performance objectives.

The linkages between our five strategic priorities and our five asset management objective areas are illustrated in Table 4.4.

Table 4.4: Linkage between Strategic Priorities and Asset Management Objectives

ASSET MANAGEMENT OBJECTIVES / STRATEGIC PRIORITIES	Build a high performance safety culture	Deliver excellence in asset lifecycle management	Deliver demonstrably optimised business performance	Deliver value to our customers – now and in the future	Create a high performing and respected Aurora Energy team
Health and Safety	✔	✔			✔
Customers		✔	✔	✔	✔
Community and Stakeholders	✔				✔
Service Performance		✔	✔	✔	
Asset Management Capability	✔	✔	✔		✔

Details of our five asset management objective areas are set out in the following sections, together with information about historic performance, key performance targets and our strategies to achieve the targets.

4.6.1. Health and Safety

Our network assets and asset management activities have the potential to pose hazards to the public and to workers. Effective management of health and safety risks associated with our assets and activities is fundamental to our business and to fulfilling our statutory obligations. We set out our commitments to health, safety and the environment in a policy published on our website.[34]

Safety is our foremost priority. As an electricity asset owner, we have responsibilities for safeguarding those working on our network and the wider public, and as an employer, for ensuring an injury-free workplace.

Box 4.3: Safety Objective
Our safety objective is to safeguard the public and ensure an injury free workplace

Historical context

A new system for recording and analysing health and safety incidents was established on 3 July 2017 following our separation from Delta. The incident data currently available to us from earlier years represents the overall activity of Delta, including their work on assets owned by others. 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.

[34] Health, Safety and Environment – Our commitment to you, Aurora Energy, 2018

Our new incident reporting system includes improved assessment of the potential and actual severity of the incidents. The incident classification system now includes the recognition of key risk areas (critical risks). This allows us to focus our health and safety management on the areas of most concern.

Performance targets

Our key performance targets for health and safety are set out below. Both of these targets were achieved in 2018. Recognising the need for continuous improvement, the key strategies and initiatives described below will help drive a stronger safety culture and over time this will improve our TRIFR towards a best practice performance level of 3 to 3.5.

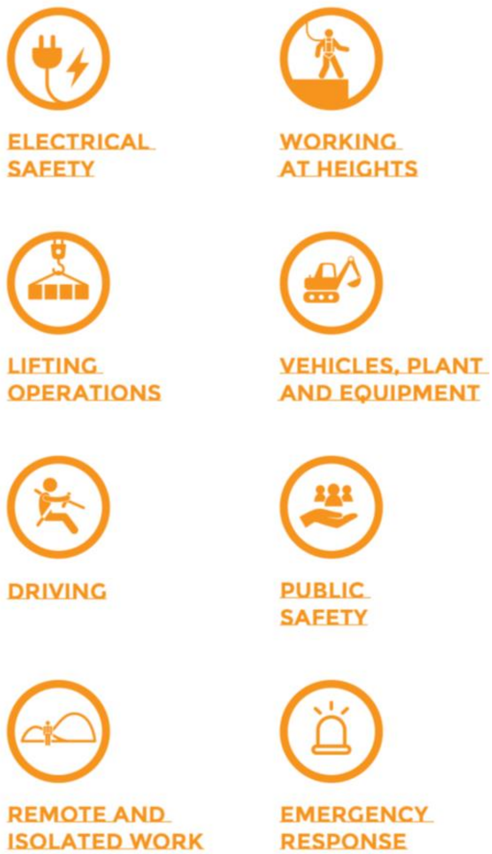
Table 4.5: Health and safety performance targets

Target	2018	2019	2020	2021	2022	2023
TRIFR[35]	4.63	< 4.75	< 4.50	< 4.25	< 4.00	< 3.75
Actual harm to public	0	0	0	0	0	0

Key strategies and initiatives

During the year we launched our Safety Choices programme to embed safety as a leadership priority and make safety highly visible as a core value.

We defined eight critical risk areas (depicted on the right). Safety rules were developed for each risk area that reinforce the required behaviours to keep everyone safe.



Our key strategies and initiatives that focus on safety as a core value are set out below.

- implement a safety culture improvement program that will engage our management, staff and service providers
- invest in safety leadership training
- focus on improving the control of critical risks
- improve the reporting of hazards and near miss incidents
- enhance our approach to Safety-in-Design
- complete our current prioritised programme of replacement of assets that present a risk to the public or to our service providers
- promote public awareness of safety around our network.

We have an ongoing public awareness programme to inform the community about keeping safe around our electricity network. Targeted safety messages are promoted through print and online advertising

35 Total Recordable Injury Frequency Rate (TRIFR) per 200,000 hours worked

on the hazards of working near overhead lines, digging near underground cables and being prepared in the event of power outages. A new safety message around trimming trees near electricity lines was recently added, supported by a safety guide for tree owners and advice on what species to plant (or avoid) near power lines.

4.6.2. Customers

Chapter 2 set out key information regarding the types of customer we supply, and what is important to them. It described our plans for improving engagement with customers – this will improve our understanding of their needs and help us meet them. We have identified a range of customer needs including: preference for reasonable prices; up-to-date and accurate information on faults; timely response to outages/complaints; and the underlying need for a safe and reliable supply of electricity.

Our performance

We have carried out regular telephone surveys of a sample of residential and small business customers since 2006. The main findings from the most recent survey (of 400 customers) in October/November 2017 are set out below. Chapter 2 includes further information on our customer surveys.

- The majority of customers who had experienced an unplanned interruption in the previous six months considered that restoration had occurred within an acceptable time frame.
- Those customers who were notified of a planned outage in the previous six months were satisfied with the amount of information provided and the period of notice.
- The majority of customers who had experienced an unplanned interruption, and contacted Aurora Energy were satisfied with the communications that they received.
- Most customers who contacted Aurora Energy over other matters in the previous six months were satisfied with the performance of the staff member who handled their enquiries.

These findings are broadly consistent with the results of the same survey over previous years. However we acknowledge that the sample of customers is relatively small and will expand these engagements in future.

Objectives and targets

Our AMP goal is to maintain meaningful engagement with customers and improve their experience when dealing with us.

Box 4.2: AMP Customer Objective

Our objective is to understand the diverse needs of our customers, and provide service levels that will meet their needs on a sustainable basis, taking into account the trade-offs between performance, risk and cost.

Our customer-related objectives include:

- we provide notice to affected customers in advance of all planned interruptions
- we provide timely and accessible information for customers about unplanned interruptions
- our communication with customers is effective and strengthens our relationships with them
- our processes for new connections are efficient and effective
- we enable the technology choices of our customers.

Our key performance targets for our customer objective area are set out below.

Table 4.6: Customer performance targets

AREA	PERFORMANCE TARGETS
Customer satisfaction surveys	Survey results demonstrate a steady or improving trend
Notification of planned interruptions	No failures to notify at least 10 business days in advance
Response to customer enquiries	Maximum time for an appropriate response to enquiries is 7 days

Key strategies and initiatives

We acknowledge the inconvenience to customers when their power is off, especially during colder weather. During winter, we trialled two new initiatives to lessen the impact on customers. New guidelines were introduced that limit the timing and duration of planned outages during winter. We also trialled drop-in centres for larger winter outages to provide a dry, warm space for affected customers.

Our key strategies and initiatives to achieve our objectives and targets are:

- continually increase transparency in our dealings with customers
- increase visibility of our plans to ensure customers can provide informed feedback
- provide effective notice to impacted customers in advance of all planned interruptions
- provide timely and accessible information and updates for customers about unplanned interruptions
- build relationships to ensure we grow our credibility and build trust
- maintain a customer charter setting out our promise to customers and minimum customer service standards
- review our customer connection process to improve connection timeframes and service
- use customer voice panels to better understand customer needs.

4.6.3. Community and Stakeholders

As we carry out a major renewal of our network assets over several years, it is important that we engage with our stakeholders and the communities that host our assets to ensure we are meeting their expectations.

Our assets are present in almost all communities in our region. Most of our assets are located on road reserves or on land that we do not own. Approximately half of our Central Otago network assets are located on private land. We also have a significant number of assets on land that is managed by the Department of Conservation.

Although we have some rights of access under legislation, it is essential that we have effective ongoing relationships with our communities and stakeholders, so that we can safely and effectively manage the network.

We also require effective ongoing relationships with three District Councils, one Regional Council, Department of Conservation, and Heritage New Zealand.

Box 4.3: Community and Stakeholders Objective

Our objective is to maintain effective relationships with communities and landowners, to ensure that we can continue to access and maintain our assets.

Historical performance

Our interactions with stakeholders provide a wide range of information that can assist us to meet their expectations. We are currently recording important information from landowners about access over private land, including capturing the routes of access tracks into our geospatial information systems.

We have also entered into a land access agreement with the Department of Conservation.

Objectives and targets

Our objectives for community and stakeholders include:

- communicate effectively and strengthen relationships with our stakeholders across our region
- limit the impact of our assets on adjacent landowners and communities
- maintain the trust and respect of the agencies and authorities that we work with
- obtain support and co-operation from private landowners, councils and roading authorities to enable effective vegetation management around our network assets
- our activities are sustainable and have low impact on the environment
- we have a shared understanding of the future needs of our communities.

Specific performance targets for our community and stakeholders objective area are set out below.

Table 4.7: Community and Stakeholders performance targets

Area	Performance Targets
Environmental performance	Zero breaches of the Resource Management Act
Heritage Act	Zero breaches of the Heritage New Zealand Pouhere Taonga Act 2014

Key strategies and initiatives

Our key strategies and initiatives to achieve our objectives and targets are:

- review our processes for communication with landowners
- capture and record instructions from landowners about access routes and conditions of access
- record and act on feedback from landowners
- consult proactively with stakeholders and communities impacted by our activities
- ensure that consents under the Resource Management Act are obtained where required
- engage with Heritage New Zealand, to ensure that we can readily identify sites of interest
- participate in regional / district plan reviews
- maintain effective relationships with the owners and managers of road transport corridors, and the other utilities who seek access to the road corridor
- engage with regional and district councils to inform our forecasts and development plans.

4.6.4. Service Performance

The service our customers receive from the network is largely determined by the assets we use to deliver their electricity. These assets and our network architecture reflect historical trade-offs between cost and service. Achieving target levels of service performance is often a long-term undertaking.

Box 4.4: Service Performance Objective
Our objective is to deliver a cost effective and sustainable level of service to customers.

Historical performance

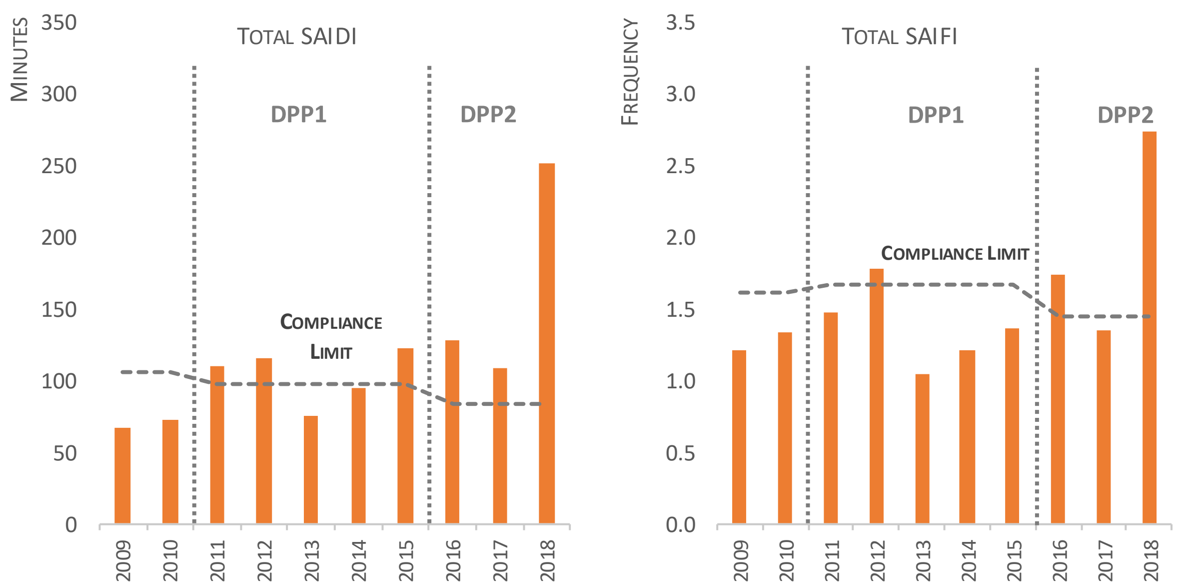
We have exceeded our SAIDI limits during the last four regulatory years, RY15 through RY18. The SAIFI limits were also exceeded during RY16 and RY18.[36] Further details are published in our Annual Compliance Statement for the assessment period ending 31 March 2018.[37]

Our historic SAIDI and SAIFI performance is illustrated in Figure 4.3 below. The significant increase in SAIDI in the year to 31 March 2018 is largely a result of the planned interruptions that were required to enable our major renewals programme in that year. Safety-related considerations on the extent of live-line work and the introduction of 'patrol first' response to faults have also contributed.

Analysis of the underlying raw data (before normalisation) reveals a slowly deteriorating trend in unplanned SAIDI over the past 15 years, but an improvement in unplanned SAIFI over the same period. Further analysis of historical performance, including a breakdown of the main causes of unplanned interruptions, is included in Appendix C.

The extent of unplanned interruptions, and the long-term deteriorating trend in SAIDI reinforces the need for our programme of network renewals and asset management improvements.

Figure 4.3: Historical Service Performance



[36] SAIDI and SAIFI are indices that measure reliability performance based on interruption duration and frequency, respectively.

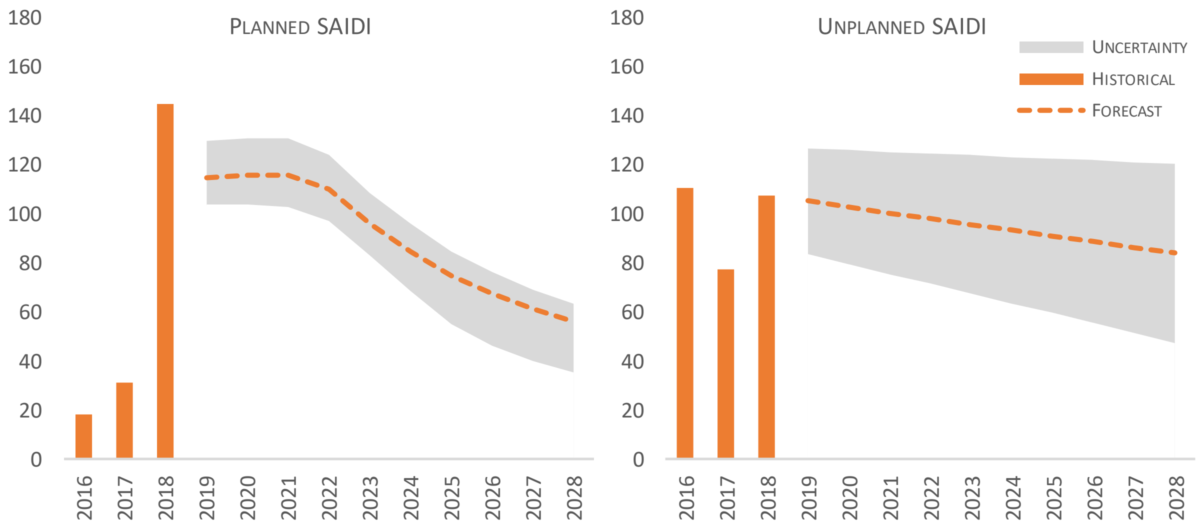
[37] Annual Compliance Statement for Assessment Date 31 March 2018.

Objectives and targets

Our current investment plans aim to ensure a safe, reliable and resilient network. However, the planned outages required to implement these plans mean that our planned outage allowances, determined as part of default price-quality path (DPP) regulation – which is based on historical outage levels – will not accommodate the work that we need to undertake. Figure 4.4 below shows our current forecast trajectory for SAIDI, including uncertainty bands either side of our forecast.

Further information on the uncertainty ranges, details of our SAIFI forecasts (including charts) is provided in Appendix C.

Figure 4.4: Forecast SAIDI Performance



In the short-term, we will need to maintain similar levels of planned interruptions so that we can safely access network assets during our renewal and maintenance works. These elevated levels of planned outages will reduce over the period both as our planned volume of work in overhead assets reduces and as we further improve our delivery capability and outage management. Our forecast assumes gradual reductions in the number and length of required outages as we embed process improvements (discussed below).

We expect there to be some year-to-year variance over the period as our work programmes are refined to reflect the changing state of our assets. However, we expect this variance (or uncertainty) to provide more opportunity for improvement than risk of higher planned outage levels.

For unplanned SAIDI and SAIFI, we expect our recent and planned investments will have a positive impact on performance and expect both measures to reduce over the period (subject to the year-to-year variance in weather events, such as major snow storms in Central Otago). However we do not yet have a clear view of how much improvement will be gained, or how soon as reflected by the wide uncertainty range above.

The following table sets out our reliability targets for the next five years.

Table 4.8: Forecast SAIDI and SAIFI (normalised, by regulatory year)

MEASURE	2019	2020	2021	2022	2023	2024
SAIDI - Planned	115	116	116	110	96	85
SAIDI - Unplanned	105	103	100	98	96	93
Total	**220**	**219**	**216**	**208**	**192**	**178**
SAIFI - Planned	0.51	0.51	0.50	0.43	0.36	0.31
SAIFI - Unplanned	1.96	1.90	1.83	1.76	1.70	1.63
Total	**2.48**	**2.41**	**2.33**	**2.19**	**2.06**	**1.94**

We plan to further refine these targets in the coming months and to consult with customers and other stakeholders on the targets we will propose as part of our CPP application.

Key strategies and initiatives

This year we have developed a Reliability Management Plan (RMP) which aims to ensure our approach to managing reliability is consistent with good practice. A key objective is improving our performance against quality standards given significant increases in planned outages due to our expanded works programme and increasing unplanned SAIDI and SAIFI. Appendix C sets out more detail on our RMP.

Some examples of the improvements that the RMP aims to deliver are set out below.

- identify and execute operational changes to reduce the frequency and duration of outages
- establish a dedicated function in our business to review and analyse the underlying trends and causes of unplanned outages and develop performance improvement initiatives
- develop new, broader measures of performance to allow a better understanding of the service customers receive
- enhance network operations centre functions to improve situational awareness and ensure timely escalation and response
- conduct in-depth reviews of large incidents, including our response to storms
- using improved communications, we will reduce the impact of outages on customers
- maximise the work safely undertaken during planned outages
- establish and monitor key performance indicators for field service provider response
- expand the use of proven standard designs to reduce potential for type issues
- review network architecture to identify low cost opportunities for improving resilience.

4.6.5. Asset Management Capability

Our asset management capability includes the skills, knowledge, competencies, systems and tools that we require to achieve our objectives.

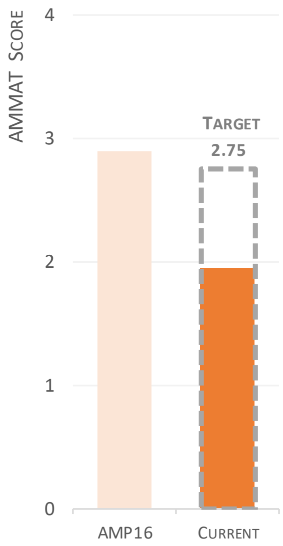
Box 4.5: Asset Management Capability Objective
Our objective is to develop our skills, knowledge, competencies, systems and tools to help achieve our health and safety, customer, community and stakeholder, and network service performance objectives.

Historical context

Our separation from Delta has required the development of significant new asset management capability. This work is proceeding, and will be a major focus for improvement initiatives over several years.

Asset management maturity assessment

We have undertaken an internal review of our asset management maturity, using the AMMAT tool from schedule 13 of the Electricity Distribution Information Disclosure Determination 2012. The AMMAT tool has 31 assessment questions. The result of our self-assessment is an overall average score of 1.94. This is significantly lower than our previously reported assessment score of 2.9 in 2016. It places us at the lower end of the range of the self-assessments published by other electricity distribution businesses. As depicted to the right, we have put in place an interim target of an AMMAT score of 2.75 by 2021.



Further details of our current AMMAT assessment are given in Chapter 7.

Our revised AMMAT scoring reflects a more robust assessment of our existing asset management system, and confirms the areas where significant improvement is required. We have used the internal review of our maturity as an important input to the development of our asset management improvement plan.

Objectives and targets

Our overarching goal is to build and maintain the confidence of customers and stakeholders in our stewardship of the network. Over time, we will seek to achieve full alignment of our asset management system with the ISO 55000[38] family of asset management standards. We plan to use certification against ISO 55000 to monitor and demonstrate our progress to stakeholders.

[38] ISO 55000 is an internationally recognised standard that provides an objective reference for good practice asset management.

Box 4.4: Asset management improvement objective

Our objective is to seek independent certification of our asset management system to ISO 55000 by 2023. As an interim step we are targeting an AMMAT score of 2.75 in 2021.

Key strategies and initiatives

Our key strategies and initiatives to achieve our objective and targets are:

- enhance our asset strategies and our fleet-based asset decision-making approaches
- clarify and confirm key requirements for asset and network data as the foundation of effective decision making, and identify significant needs for improvement
- define and establish programmes for data gathering and data quality improvement
- develop improved risk-based models and decision support tools for use in investment planning
- recruit, retain and develop staff with appropriate skills to lead our asset management activities and extend our capability
- develop improved asset management information systems that will provide effective support for improved works management and asset management decision making
- establish and maintain effective systems of internal review, feedback and learning, to support continuous improvement
- develop improved cost estimating and works planning capability.

Further details of our these improvement initiatives are given in Chapter 7.

4.7. ASSET MANAGEMENT GOVERNANCE

Asset management governance is our term for the system of roles, responsibilities, authorities, and controls that support our asset management decision-making. This section explains our approach to asset management governance and decision-making.

The establishment of an asset management function within Aurora Energy, and transition in the role of Delta to an arms-length service provider has required significant changes to governance and management. In addition, our asset management governance and structures will continue to evolve as we improve and expand our asset management capability and capacity.

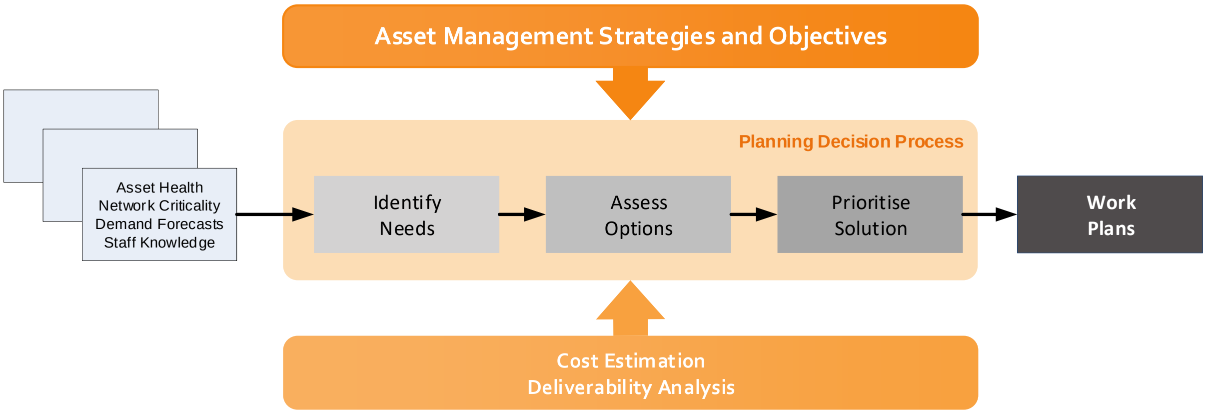
Our asset management decision-making occurs at various levels in our organisation – from the Board to engineering planners to field staff. Asset management decisions are undertaken with a system of responsibilities and controls that reflects the cost, risk, and complexity of the decision being considered.

We describe our organisational structure and its main governance levels in Chapter 2.

4.7.1. Decision making

We are transitioning to a more formal approach to decision-making for network investments, as illustrated in Figure 4.5 below.

Figure 4.5: Planning Decision Process



The main steps in the asset planning decision process as illustrated above are:

- **Identify needs:** this involves the systematic review of network safety risks, capacity constraints, security, reliability, asset condition, type issues, maintainability, spares availability, and a range of network and site-specific feedback. For asset types where an asset health model is available, it will include review of asset health forecasts. The identified needs are given a priority ranking, based on a range of inputs including network and asset strategies, risk assessments (including criticality attributes), and subject matter expert judgement.
- **Assess options:** in this step potential options are developed for each identified need. These options are defined and costed to varying degrees based on the complexity, scale of the identified need and the costs of feasible solutions. The potential solution is evaluated against approval criteria and prepared for entry into expenditure plans.
- **Prioritise solutions:** in this step, solutions that have been developed in previous stages or previous planning rounds are ranked and scheduled based on the risks associated with the identified need, deliverability, across project coordination, and trade-offs with other investment needs. A preferred solution is identified that may include bundling of multiple needs into one packaged solution. The prioritisation may occur within a particular asset type or system investment portfolio, or across multiple portfolios.
- **Work plans:** the prioritised solutions will be entered into a draft Asset Management Plan, which sets out planned works. The deliverability of the overall set of solutions is evaluated, and cross-portfolio expenditure balancing is undertaken if required. Projects in the early years of the plan will be subject to review for full financial approval in accordance with our delegated authority policy.

The degree to which the above steps have been formally adopted varies across our expenditure categories.

Delegated Financial Authority

Our delegated authority policy (FS-S018) sets out the limits to which employees can commit Aurora Energy to financial transactions or contractual obligations. The limits assigned to a role reflect whether the expenditure is Capex or Opex, budgeted or unbudgeted.

4.7.2. Service Delivery

Our field service activities, including maintenance and construction, are fully outsourced.

As described in more detail in Chapter 2, in August 2018 we concluded a process to introduce new contracting arrangements and established contracts with two new providers. The increased use of competitive tendering and the introduction of the additional service providers will lower the risk of under-delivery and help ensure we receive efficient and market-tested pricing.

The service delivery teams manage service provider contracts. The capital projects team, responsible for overseeing project delivery, is one such group.

Our works delivery process relies upon technical standards to help ensure safety, quality and cost-effectiveness. We are developing an extensive set of specific technical standards for design, procurement, installation and maintenance.

4.7.3. Works Delivery

We assess potential delivery constraints as part of our investment decision-making process. The primary factors to be considered when accessing deliverability of our works programme are set out below. Key factors include seasonal timing to avoid planned outages during peak loading periods, the necessary order of interconnected projects, resource constraints, and professional engineering judgement based on experience and expertise.

Managing contractor resource constraints

In future, we aim to maintain a steady workflow to service providers and ensure project diversity is preserved within a given year. This ensures that contractor personnel and equipment levels match our capital build programme year-on-year at a consistent level, reducing the risk of our contractors being over- or under-utilised.

Works coordination

As we refine our delivery processes, we will schedule our projects to coincide with a wider range of projects. This may cause us to bring forward, or defer if possible, projects to avoid major additional outages and related expenditure (e.g. traffic management). This includes coordination with the New Zealand Transport Agency and other utility activity (e.g. future road-widening or resealing programmes) to avoid the need to re-lay cables or excavate and then reinstate newly laid road seal.

Required outages

The feasibility and timing of projects is assessed by considering both the need for planned outages and their impact on customers (as reflected in our regulatory quality standards). While it is important to ensure outages are minimised as far as practicable to manage customer expectations, so too is balancing that with the need to address network risks and constraints that may compromise safety or impact customer supply through extended or more frequent outages.

Coordination with Transpower

We endeavour to coordinate any major network structural changes adjacent to a GXP with Transpower's planned asset replacement programmes, and also provide direction to Transpower to ensure consistency with our subtransmission upgrade plans.

Other work programmes

We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations. We seek to schedule any major substation works and upgrades to coincide with asset maintenance programmes.

4.8. Risk Management

This section describes our approach to risk management. Risk management is a fundamental asset management discipline. All our asset management decisions are linked in various degrees to managing risk. We have lifted our focus on risk and criticality thinking since separation from Delta and introduced a refined network risk-management framework.

Our risk management activity includes processes to manage safety risks, avoid capacity constraints, manage failure likelihood through maintenance and renewals, and ensure resilience to help mitigate the consequences of major events.

Risk management is applied at all levels of our organisation – from decisions at Board level, through to operational decisions in the field. The purpose of risk management is to:

- understand the types and extent of adverse trends or events that our business may face
- respond effectively to these adverse trends or events through applying appropriate controls and mitigations, so as to manage these risks to an acceptable level.

4.8.1. Roles and responsibilities

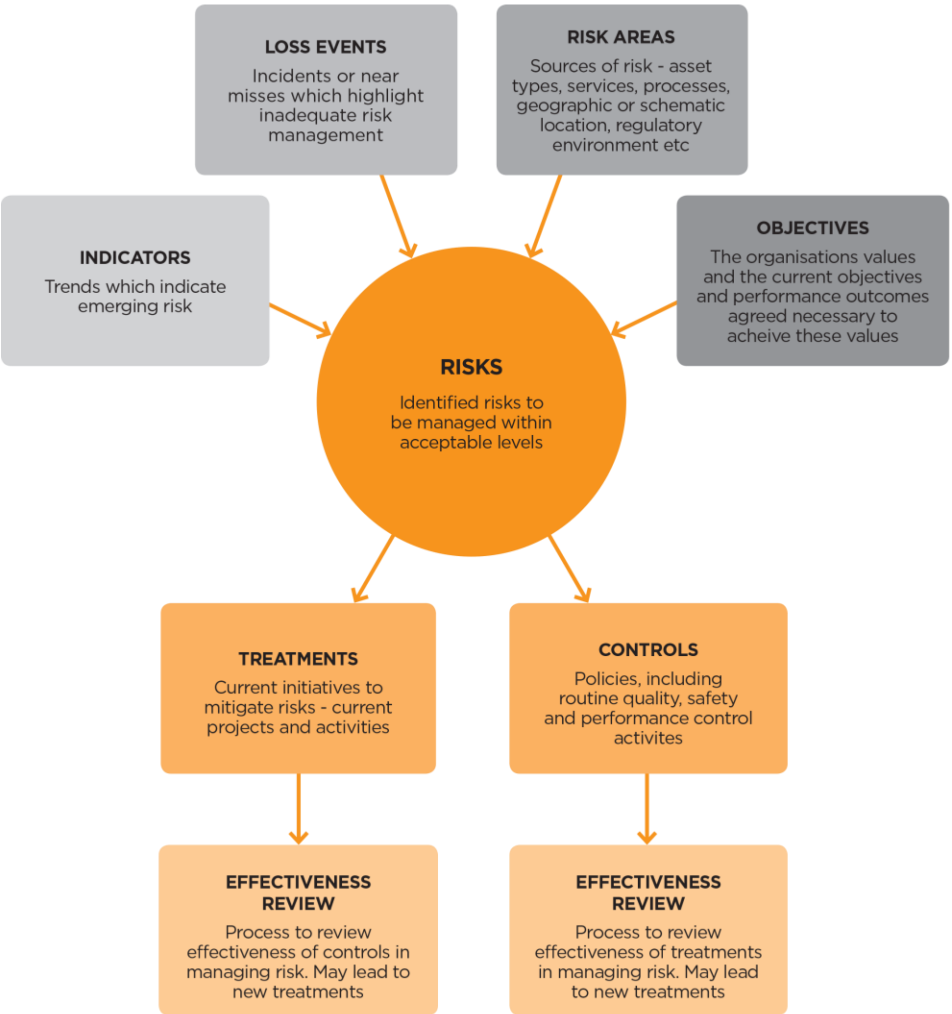
Our Board is accountable for the effectiveness of our risk management framework. This helps to ensure that risk management extends throughout the hierarchy of the organisation. The Board is responsible for governing risk policy and overseeing risk management practices. The Executive team reviews risk issues regularly, and evaluates changes in the strategic and operational environment.

Our management has responsibility for implementing the risk management framework. For example, departmental managers and employees are responsible for risk identification and the operation of controls such as policies, standards and procedures that mitigate risk within their area of responsibility. Managers also ensure staff are aware of their risk management obligations through training and assessment.

4.8.2. Risk Management Framework

Effective risk management requires a framework that is built on sound governance processes and uses effective procedures and controls. The risk framework we apply is consistent with ISO 31000, and is illustrated below.[39]

Figure 4.6: Risk management framework



In the next sections we discuss our main risk management approaches in greater detail.

4.8.3. Safety Risk Management

Our corporate values and asset management policy require that we ensure an injury-free workplace and that we strive to safeguard the public. Identifying and managing safety risks associated with our network and activities is fundamental to our business.

39 ISO 31000 is a family of standards relating to risk management codified by the International Organization for Standardisation.

Workplace Safety Risk Management

Our commitments to workplace safety includes that we:

- are committed to providing a safe working environment
- believe that safety is everybody's responsibility and that our leaders both influence and set the tone for wider safe behaviours at work and in the community
- actively seek to build a positive culture that places safety at the forefront of all that we do while recognising we must always strive to improve
- believe that all incidents are preventable. We believe that anyone can stop an unsafe act and all our people and contractors are empowered to manage and control all the hazards and safety risks they see. We expect our people to take a lead in this
- believe that everyone has the right to come to work with the expectation that they will return home safe and healthy, every day.

Our safety rules

We have established a set of safety rules based on critical risk areas where there is a significant risk of serious harm or fatality during work activities on our network. The purpose of defining the eight critical risk areas is to focus our safety behaviour and improvement initiatives in areas that will have the most impact in reducing the risk of serious harm. The critical risk areas included in our safety rules are:

- electrical safety
- working at height
- lifting operations
- vehicles, plant and equipment
- driving
- public safety
- remote and isolated work
- emergency response.

Public safety risk management

We are committed to maintaining and improving the physical safety of all assets on our network and to educating the community on how they can stay safe around electricity.

We are required to have a public safety management system (PSMS) under section 61A of the Electricity Act 1992. We maintain a PSMS that complies with NZS7901:2008 *Electricity and Gas Industries – Safety Management Systems for Public Safety*, and this is audited annually. The intent of our PSMS is to prevent serious harm to any members of the public or significant damage to their property. The methodology we adopt is to ensure that we:

- identify hazards associated with our electricity assets in both normal and abnormal conditions
- assess the risk of serious harm to the public, or significant damage to their property, that may arise from any identified hazard
- eliminate, isolate or minimise significant hazards to the extent that the residual risk is as low as reasonably possible.

4.8.4. Asset Risk Management

Consideration of risk plays a key role in our asset management decisions – from network planning and asset replacement decisions through to operational decisions. Our asset management systems and our core planning processes are designed to manage existing risks, and to ensure that emerging risks are identified, evaluated and managed appropriately. Our approach to managing asset risks is set out in more detail below.

Section 5.2 discusses our network risk framework in more detail.

Network planning

We manage risk in network planning activities by evaluating our networks against our security standards to identify existing and emerging security risks. We also review our networks against anticipated demand and connection volumes, to identify capacity risks. This is discussed in chapter 6.

Asset planning

Our asset planning processes use a variety of risk-based approaches for determining the need date for interventions. The planning methodology differs by asset type, but the consideration of risk is part of asset planning for all asset types.

We choose a planning approach for each asset type that takes into account the typical reliability performance and consequences of failure of that type of asset. This is informed through knowledge of failure modes and consequences that are specific to particular makes/models of asset. Asset interventions are then considered taking into account the costs, feasibility and reliability of inspection, testing, condition assessment and asset health forecasting.

The following table sets out our current planning approach to manage asset risks (although for some asset types we are actively working to develop a more advanced approach).

Table 4.9: Risk-driven planning approaches examples

PORTFOLIO	SUB-FLEET	PLANNING APPROACH
Support structures	Poles	Failure risk assessed through condition inspections. Renewals are prioritised on basis of risk and asset criticality, where the latter is informed by location-based safety risk.
Distribution switchgear		Replace based on condition and type, where some makes and models have identified safety risks.
Zone substations	Power transformers	Replace based on asset health (comprising condition and other factors such as availability of spares, seismic withstand capability).
	Outdoor switchgear	Replace based on asset health which accounts for factors including age, condition, maintainability and availability of spares.
Underground cables	Subtransmission	Cable to be replaced determined based on asset health/environmental risk. Due to the large volume due for replacement during the planning period we are considering reconfiguration options – rather than like-for-like replacement – to improve resilience.

Maintenance

Our approach to preventive maintenance of assets also incorporates consideration of risk. Our preventive maintenance schedules and requirements are based on consideration of the potential failure modes, and their likelihood and consequence. The preventive maintenance regime is designed to mitigate risk by identifying emerging defects before they can progress to failure, so that appropriate steps can be taken to avoid failure in service, or respond promptly if failure occurs.

Asset health and criticality modelling

We have commenced the development of asset health forecasting models to improve risk-based decision making for some asset types. These models can provide a forecast of future asset health and can also generate a forecast probability of failure, enabling us to determine the volume of work required to manage risk to an acceptable level.

The asset health forecasting technique is more suitable for some types of asset than others. It is generally more suitable and cost-effective for application to an asset type when:

- there is a large population of similar or identical assets in service
- observations and measurements of asset condition are practical, and they provide useful insight into the degradation of the asset that leads to the failure modes of most concern
- there is a time-series history of observations of asset degradation in different operating environments that can be used to calibrate a degradation forecasting model.

The effective implementation of an asset health model requires significant investment of time and also requires availability of reliable data as inputs to the model. We expect to continue to develop and refine asset health models for selected asset types over the next few years.

Our decision making for some asset types already takes into account the location-specific consequences of failure – including both network location and physical location. This is the criticality dimension of risk.

We are currently working towards the implementation of a criticality framework that will provide a consistent approach to incorporating location-specific consideration of the consequences of failure in our decision making. See Section 5.2.2 for more details on our approach to asset health and criticality.

4.8.5. Major hazards and incidents

Our network is exposed to a wide range of natural hazards and other causes of severe incidents. We have a responsibility as a lifeline utility to provide levels of resilience that will minimise loss of service when we are exposed to a major natural hazard or in the event of extensive outages. Our approach to managing the risks of major hazards and incidents is set out in Section 4.9 below.

4.8.6. Other Risk Areas

In addition to safety and asset-related risks we monitor a number of other risks. These include:

- **resourcing:** the risk of not being able to access sufficient numbers of competent staff, service providers and suppliers to implement our asset management plans in a timely manner.
- **environmental planning delays:** resource consent requirements and the possibility of objector delays creates uncertainty and the potential for delays to implementation of planned works.
- **regulatory and compliance:** failure to comply with legislative and regulatory requirements.

4.9. RESILIENCE

Planning for resilience is an essential element of asset management strategy and governance for lifelines utilities. We respond to many incidents routinely, as part of normal business. For the purposes of this section, we focus on resilience to major hazards and the more severe network incidents, including those defined as High Impact Low Probability (HILP).

4.9.1. Our approach

Our approach to resilience is based on the concepts of the four "R's" – Reduction, Readiness, Response, and Recovery, as used by emergency services, Civil Defence, emergency management organisations, and other lifeline utility operators in New Zealand:

- **reduction:** identifying and analysing risks to the business, assets and community, and taking steps to eliminate or reduce those risks
- **readiness:** developing operational systems and capabilities before an incident occurs so that the organisation is prepared, trained and tested to respond in a way that will ensure the business can return to full operational capacity as soon as is possible
- **response:** actions taken immediately after an incident occurs to protect life and assets, and take initial actions to ensure the business can consider returning to full operational capacity
- **recovery:** coordination of the organisation (and potentially external organisations) to return the business to full capability.

All lifeline services rely to some extent on some or all of the other lifeline services in order to operate. Therefore, a hazard impacting on one lifeline service is likely to have a knock-on effect on others, such as the loss of power impacting water and wastewater services. Similarly, the loss of mobile phone networks (e.g. following an earthquake) can severely impede restoration efforts, in the absence of a dedicated radio system. To mitigate the risk that arises from this interdependence, many lifeline utilities have backups (for example, on-site generators) should other lifeline services fail. We consider interdependencies between our operations and other lifeline sectors when developing our plans.

4.9.2. Potential Impacts of Natural Hazards

We have participated in the Otago lifelines project. The purpose of this project was to assess the potential impacts of hazards on the region's lifeline infrastructure, identify mitigation strategies to reduce that risk and to improve critical infrastructure resilience. This programme of work identified that storm/flooding, earthquakes and high winds are our major natural disaster risks, and these are covered in more detail below.

Storm/flooding

While distribution lines are unlikely to suffer damage from floodwaters, the biggest potential for damage is inundation of our Dunedin substations. Full restoration following such an event could take days or weeks. Critical sites in flood risk areas include:

- Transpower's South Dunedin substation (GXP) which services 17,500 customers
- Mosgiel zone substation
- our underground substations in the Dunedin CBD.

We have effectively mitigated some of these risks, for example the use of temporary barriers at Mosgiel zone substation. We are progressively addressing the remaining identified risks, including a programme to steadily remove CBD underground substations. We are also investigating a more interconnected Dunedin subtransmission network to enable load switching between GXPs.

Earthquakes

A large number of active faults lie within Otago, and many more outside the region are capable of affecting the region. While ground shaking will almost always be felt during large earthquakes, the extent of liquefaction, lateral spread and surface rupture is dependent on the size and characteristics of earthquakes and the ground conditions in the area under consideration. Planned replacements and refurbishments of a number of our zone substation buildings and asset restraints will improve their capability to withstand seismic events (refer Section 5.9).

4.9.3. Investments to Improve Resilience

We consider resilience as part of our renewals planning/decision-making processes. The planning methodology differs between asset types, but we consider resilience as part of asset planning for all asset types. The following table sets out some examples of how consideration of resilience has resulted in changes to renewals planning.

Table 4.10: Resilience-driven investment examples

PORTFOLIO	SUB-FLEET	RESILIENCE IMPACT
Zone substations	Buildings, power transformers, switchgear	Seismic assessments of key zone substation assets informed our zone substation renewals planning. Design of new buildings to an IL4 standard, reinforcements of existing buildings to IL3, asset foundation rebuilds and seismic restraints will together improve the resilience of our zone substations to major seismic events.
Underground cables	Subtransmission	We determine replacement needs for our subtransmission cables on the basis of asset health and environmental risk. As there is a substantial volume of cable coming due for replacement, options analysis includes consideration of alternate cable configurations to improve resilience.
Distribution transformers	Pole mounted transformers	We replace our large pole mounted transformers with ground mounted units. This improves resilience in the event of seismic events, but will also improve operational and public safety.

4.9.4. Emergency Procedures and Plans

Aurora Energy is defined as a lifeline utility under the Civil Defence Emergency Management Act 2002, and is required to ensure that it can operate to the fullest extent, even if at a reduced level, during and after an emergency. We are currently updating our business continuity plans to enable us to respond to events beyond our control, as set out below.

Business Continuity Programme

We have a legacy set of business continuity plans in place to respond to major incidents. The programme includes business continuity response plans, response guide for use in incidents, responder training, and exercises to demonstrate capability and competence.

We are currently reviewing and updating these plans with a view to developing more tailored plans, designed to manage and support a number of scenarios, including IT system failure, major infrastructure failure, natural disasters and pandemics.

Contingency Plans

Contingency plans are used to assist in the timely restoration of supply following an outage to a major distribution feeder or zone substation. It should be noted that it is not possible to transfer peak loads at most substations for rare double-failure events such as failure of both subtransmission circuits or both transformers at the larger substations.

Participant Outage Plan

Our participant outage plan is designed to comply with the system operator's security of supply outage plan. The participant outage plan details how we would manage severe generation shortages and / or significant transmission constraints.

Contingency Plant

We own mobile substations and generators as described in Chapter 5. The range of these assets are designed to provide backup to our N-security zone substations and HV feeders under a variety of contingent scenarios.

4.9.5. Incident Management

Our response planning incorporates the use of the Coordinated Incident Management System (CIMS), which is used by emergency services, civil defence emergency response organisations, and many utility operators in New Zealand for managing the response to an incident involving multiple responding agencies.

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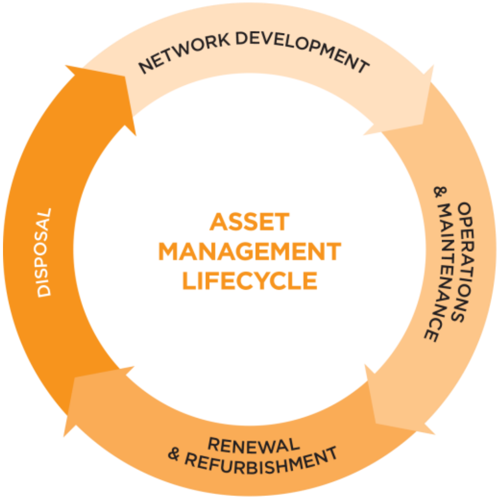
5. LIFECYCLE MANAGEMENT

This chapter explains our approach to managing our asset fleets, and sets out our fleet plans.

5.1. INTRODUCTION

Effective asset management relies on a holistic approach that considers the full asset lifecycle. The lifecycle includes the creation of the asset, operation and maintenance over its lifetime, and decommissioning and disposal at end of life.

Figure 5.1: Asset Management Lifecycle



The Network Development stage is described in Chapter 6.

Chapter 5 explains our approach to fleet management, encompassing the remaining three stages, for each of our asset fleets. There are several lifecycle-based considerations when undertaking asset management activities. Some of the aspects we consider as part of our decision making are:

- seeking to achieve the lowest effective cost-of-ownership over the lifecycle of the asset, from planning through to disposal. When determining lowest lifecycle cost we aim to consider costs associated with customer outages as well as safety and environmental costs
- decisions made at the planning stage have a major bearing on our ability to operate and maintain an asset, the lifecycle cost and the timing of asset renewal
- Complex decommissioning and removal of assets can create a future burden if this has not been considered and prepared for from the outset.

5.2. FLEET MANAGEMENT

Fleet management includes planning, construction, and commissioning of assets, plus all the activities we undertake over the asset's lifecycle. It includes the renewal, operation and maintenance of the asset and its eventual disposal.

5.2.1. Operations and Maintenance

The operations and maintenance stage includes network operations, maintenance, vegetation management and spares management. Vegetation management is discussed in Section 5.11.

Network operations

The primary role of network operations is to ensure a constant supply of electricity to our customers by operating the network in a way that ensures we meet network, operational, safety, and asset performance objectives on a 24/7 basis. Key activities are real time network control, monitoring, event response and planning for equipment outages to enable safe access to network assets. Our 24-hour control room manages the operations function for the Dunedin network, while the Central Otago network utilises a control room during office hours together with an after-hours standby controller. We are in the final stages of implementing 24/7 operations from either Dunedin or Cromwell, thereby creating site and resource resilience.

Our operators must consider factors such as how asset loading and operation frequency affects asset life and performance, and how to safely remove assets from service for maintenance without compromising performance. Operations activities provide feedback to the planning process on network and asset performance or risks.

Maintenance

Maintenance is the care of assets to ensure they provide the required capability in a safe and reliable manner throughout their lifetime. It involves monitoring and managing the deterioration of assets and, in the event of a defect or failure, restoring the condition of the asset. Feedback from maintenance activities is used to improve our asset standards and planning processes, as well as to inform our Capex renewals programme.

Note that the life cycle approach requires us to make trade-offs between maintaining our assets in service (Opex) and replacing or refurbishing[40] them (Capex). For example, we may increase the frequency of maintenance for a particular asset type to increase asset life/defer renewal.

Our maintenance activity is split into three types.

- **Preventive maintenance:** this encompasses inspections, condition assessment and servicing. Typically, these activities are carried out on a regular basis (for example, every three months, annually, every six years) in accordance with our maintenance standards. Recorded condition assessment data is used for analysis, forecasting, and renewal planning. Defects and repair work (corrective maintenance) also arise from preventive maintenance.[41]
- **Corrective maintenance:** this is planned work arising from preventive maintenance work or as a follow-up to a fault (following service restoration). It includes defect rectification, repairs and replacement of minor components to restore the condition of an asset. Work in this category is prioritised and scheduled on the basis of a number of factors. Failure to undertake this work increases reliability and safety risks.

40 Refurbishment is (generally) capital work that extends the expected life of an asset. Where expenditure is required to ensure that an asset is capable of meeting its design output, this is generally classified as maintenance (Opex).

41 Our preventive maintenance category is a subset of Routine and Corrective Maintenance and Inspections (RCI) used in Information Disclosure. Our corrective category is also included within our RCI disclosures.

- **Reactive maintenance:** this is reactive work, including fault response and emergency switching, carried out in response to an unplanned event or incident that impairs normal operation. Unlike the other maintenance activities, this work is dispatched by the control room or standby controller. Failure to undertake this work in a timely manner will adversely affect the service provided to our customers and may increase public safety risk.[42]

We forecast our maintenance works by activity type.

- For preventive maintenance, our forecasts combine the tasks and frequencies of work set out in our maintenance standards with defined unit rates.
- For corrective maintenance, our forecast is based on the historical percentage of defects and our expectation of how that trend will be affected by age, condition, and planned renewals. Standard unit rates are also used for this work.
- For reactive maintenance (faults) our forecasts are based on historical trends taking into account changes to the asset base.

Details on the maintenance activities that apply to specific asset fleets are discussed in the fleet sections of this chapter. Chapter 8 sets out our forecast operations and maintenance expenditure for the planning period.

Spares Management

Spare parts for our assets, retained in appropriate locations, are required to maintain reliable supply. We retain both strategic and critical spares.[43] The number and type of spares retained for each asset varies depending on whether it is a subtransmission, distribution asset, or zone substation asset, and whether it is a new or legacy asset. Spares management can be complex for legacy assets as there is often a large number of different makes and model in service, as in the case of switchgear. Standardising on equipment manufacturer, type, and rating allows asset availability to be maintained with fewer spares.

We plan to further develop our approach to spares management, including developing formal spares strategies for each asset fleet. These strategies will apply a standard approach to determine the number and locations of critical spares, considering the expected impact of various equipment failures, the number of each asset type in service and the risk each one represents. The outputs of this work will form the basis of our spares management requirements set out in our revised logistics arrangements.

5.2.2. Refurbishment and Renewal

Asset renewal Capex is associated with replacement of ageing, damaged or under-performing assets with like-for-like or new modern equivalents,[44] or the refurbishment of existing assets to extend their useful life or increase their service potential.

As assets deteriorate, they eventually reach a state where ongoing maintenance to keep them safe and serviceable becomes ineffective or uneconomic. Refurbishment and replacement are key activities to

42 Our reactive maintenance category is equivalent to System Interruptions and Emergencies (SIE) used in Information Disclosure.

43 Critical spares are items that are unique to a particular asset, and whose absence would negatively impact asset availability, safety, the environment, or our ability to meet regulatory requirements. In contrast, strategic spares are items that can be used for multiple applications or be installed temporarily as substitutes for failed components.

44 Expensed replacements (Opex) are included under our corrective maintenance portfolio

manage the condition of our asset fleets, manage safety risk and network performance, manage resilience, and meet regulatory and legislative requirements. We may need to replace assets to manage obsolescence. Our approach to renewal varies by asset fleet.

Several factors are taken into consideration when assessing assets for renewal, including age, condition, safety risk, performance, lifecycle cost and any known type issues. We use two main approaches to identify and prioritise our renewal investments – individual project and fleet-based.[45]

Risk Framework

Risk management is the primary driver for our network investments, particularly asset renewal. We use an evolving risk framework to understand the cause, effect and likelihood of asset failures. This analysis is used to trigger and prioritise investments to manage the identified risks to an acceptable level. Using a risk-based framework is necessary to effectively identify assets that require proactive intervention.

Our overall approach to risk assessment is broadly consistent with the approach being undertaken by WSP in its review. We expect the WSP report to provide useful inputs to our risk analysis and to help us refine our risk assessment methodologies.

Given the diverse range of risk assessments required and the varying certainty of data inputs, we are transitioning to two broad approaches to risk analysis:

- **Tailored analysis**: is used for large projects that have well-defined information to support project-specific analysis. These projects tend to require individual, tailored investigation, e.g. replacement of power transformers.
- **Volumetric analysis**: is used for smaller, higher-volume works that are reasonably routine and uniform. The analysis is fleet-based and assesses multiple assets to forecast future renewals.

For some fleets (e.g. power transformers) it is likely that we will transition to a two tier approach. That is, volumetric analysis identifies a potential risk requiring intervention and this is further investigated through tailored analysis. We explain these approaches in more detail below.

Tailored Analysis

We have started to apply this approach to the renewal of major assets and to zone substation and subtransmission upgrades. These large projects are individually identified and planned with project-specific options analysis and tailored cost estimates.

This approach uses a subset of our corporate risk framework, emphasising the following dimensions:

- **safety risk**: assessing the potential likelihood and consequences of asset failure for the general public, service providers and employees
- **reliability**: includes the success of investment options in ensuring assets remain available (reducing VoLL[46] risk) and reducing the likelihood of outages caused by asset failure
- **environmental**: determining the impact of asset failure on the environment, the community, and our environmental obligations.

45 These approaches are also used for our network development investments, as discussed in Chapter 6.

46 Value of Lost Load (VoLL) is the economic cost to customers caused by the loss of electricity supply, and is normally measured in $ per kWh of lost energy

The corporate risk framework is applied to determine the overall level of risk, which may include more than one risk category (e.g. reliability and safety). The level of risk is either above or below the line of acceptable risk tolerance as shown in the diagram below.

Figure 5.2: Tailored analysis risk matrix

		Impact				
		Insignificant	Minor	Moderate	Major	Catastrophic
Likelihood	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

Projects that drive a risk level down across the risk appetite boundary (yellow line) are justified by a requirement to take 'all reasonable practical steps' to reduce risk, while projects that reduce risk outside of the "Intolerable Risks" area should be justified by cost benefit analysis.

Volumetric Analysis

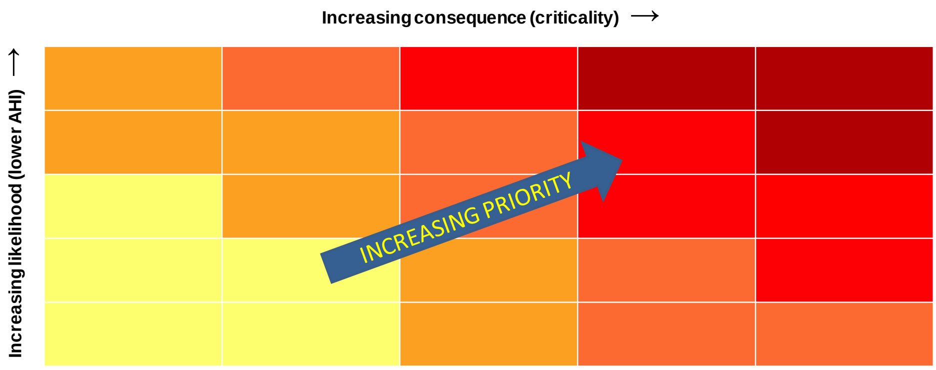
We have started to apply this approach where there is a large number of similar assets. For example, we use a combination of asset health and criticality to prioritise our renewal plans for our pole and conductor fleets. The specific assets to be replaced are identified closer to delivery, when factors such as condition of individual assets are assessed. Medium-term expenditure is estimated based on renewal volumes and average unit costs.

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

– **Asset health**: we define 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 failure-risk, 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.

We then use a combination of asset health and criticality to reflect asset-related risk. This approach is used to support prioritisation within our planning processes. Our asset health and criticality frameworks have been designed to be used together. An illustration of the concept is shown below.

Figure 5.3: Illustration of volumetric risk analysis



The main applications of this approach are forecasting the overall risk in our fleets, and identifying assets that may be particularly at risk and that should be prioritised for intervention. This approach provides a consistent basis for monitoring asset fleets over time. For certain fleets, consistent application of this methodology is being progressed through the refinement of our Condition Based Replacement Model (CBRM).

In the remainder of this chapter we outline our lifecycle approach to each fleet. In general, our long-term renewal forecasts are based on asset health/condition with short term prioritisation of the forecasts being based on risk. This prioritisation occurs both within and across fleets.

Asset Health

Asset health reflects the expected remaining life of an asset and serves as a proxy for likelihood of failure. It is the main driver behind our asset replacement and renewal investments, as assets in poor health have an increased risk of failure, leading to additional reliability and safety risks.

We have used asset health modelling to estimate future renewal volumes for most of our fleets. Currently, most of these asset health models are simple age-based models, utilising the fleet age profile relative to expected asset life. Some of the models account for additional factors such as those described below. We plan to develop our asset health models – particularly for the most critical/highest expenditure fleets – to incorporate additional factors where relevant. These may include:

- asset condition (including observed and measured condition data)
- known defects or 'type issues' that effect certain assets
- manufacturer/model
- factors that affect the rate of degradation, such as location near the coast
- issues that will limit expected life such as compliance with regulations or manufacturer support/spares availability
- survivor curves, which estimate the percentage of the asset population that has historically 'survived' to a given age.

Table 5.1 sets out our asset health categories, including the basis for the categories and the expected replacement period.

Table 5.1: Asset Health Categories

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

Based on AHI forecasts we can estimate the required future volume of asset interventions for our asset fleets. These are then used to inform our expenditure forecasts. The approach and methodology is still in development and is continuously being improved.

It should be noted that when remaining life is zero, it does not mean that failure is necessarily imminent, but does indicate that an intervention is likely to be required and should be investigated.

Asset Criticality

We are working towards prioritising maintenance and renewal work on the basis of criticality for many of our asset fleets. The criticality assigned to an asset reflects the consequences of failure of that asset in terms of public safety, reliability and other factors. For example, overhead assets in built-up/highly populated areas will be assigned a higher criticality rating than those in lower density areas because of the relative risks. Similarly, assets located near facilities such as parks, schools and major roads (points of interest) are considered more critical. For assets within zone substations, criticality focusses on reliability. For specific larger assets, inputs are tailored to the particular need.

We have developed a criticality framework for several of our fleets. We are currently looking at ways to incorporate it consistently across our planning processes, and all our asset fleets.

5.2.3. Disposal

Asset disposal follows the decision to remove it from our network, either because it is being replaced or has become redundant. Disposal activities include planning for disposal, decommissioning the asset and site restoration. Expenditure is treated as Capex if it is associated with a renewal.

Some assets such as underground cables, may be left in situ, but most are removed and safely disposed of. Concrete poles, for instance, are recycled by a local facility. Servicing and repairs may also result in waste products or failed components that require disposal.

Disposal Options

Asset disposal works have many similarities with capital projects, including considering cost, safety, environmental impacts, and project management. Additional aspects that are specific to disposal works are site restoration, termination of support activities and removal of asset information.

The options for asset disposal are strongly influenced by the particular trigger or driver being addressed but will generally include retaining the asset as a complete spare or as parts for other assets, selling it as a functioning asset or as scrap, or disposing of it to a waste management facility. The option we select depends on a number of factors, including salvage value, viability of the asset as a spare and the presence or otherwise of hazardous substances. We may choose different disposal options for different components of the asset.

When considering disposal options, we actively seek opportunities to re-use, sell or recycle redundant assets. Our preference is to recycle, sell or re-use where it is practical and cost efficient to do so. When re-use is not feasible or practical, we dismantle and dispose of redundant assets and where possible recycle the associated materials. We dispose of surplus assets and waste material in a way that poses minimal risk to employees, contractors, the public, and the environment.

Waste Management

Consistent with our safety and environment objectives we ensure waste materials are disposed of in a responsible manner. In the majority of cases disposal is a relatively low-cost activity; special disposal requirements, if they exist, are considered at an early stage. Disposal costs are considered as part of the overall lifecycle costing.

Site Restoration and Reinstatement

When substation assets are decommissioned and removed, part or all of a site may be able to be re-used or restored. Future use of the site must take into account health and safety and environmental considerations, particularly where hazardous wastes are concerned, for example, asbestos and lead-based paint. Identifying, managing, and removing contaminated soil can have a significant disposal cost.

5.3. ASSET FLEETS

To support our asset management approach we define a set of asset fleets, which forms the basis of our day-to-day asset intervention strategies. The fleets and the main asset types included in each are set out in Table 5.2.[47]

Table 5.2: Fleet/Asset Mapping

FLEET	ASSET TYPES
Support structures	Poles
	Crossarms
Overhead conductors	Subtransmission conductor
	Distribution conductor
	LV conductor
Underground cables	Subtransmission cables
	Distribution cables
	Low Voltage (LV) cables

[47] These portfolios differ from the asset categories specified by Information Disclosure as they better reflect the way we manage these assets and plan our investments.

FLEET	ASSET TYPES
Distribution switchgear	Reclosers and sectionalisers
	Ground mounted switchgear
	Pole mounted fuses and switches
	LV Service/Link Pillars
Distribution transformers	Ground-mounted distribution transformers
	Pole-mounted distribution transformers
	Voltage regulators and auto transformers
	Mobile distribution substations
Zone substations	Buildings
	Power transformers
	Switchgear
	Ancillary equipment
Secondary systems	Remote Terminal Units (RTUs)
	Protection
	Batteries and DC supplies
	Metering

The following sections describe our lifecycle management approach and expenditure forecasts for each of the asset fleets. A description of vegetation management and asset relocations is also provided in the sections below.

5.4. SUPPORT STRUCTURES

This section describes our support structures fleet and summarises our management plan for our pole and crossarm assets.

5.4.1. Fleet Overview

The support structures fleet primarily comprises pole and crossarm assets. It also includes a small number of steel lattice towers (for example, across Otago Harbour). These assets support our overhead conductor assets and together make up our extensive overhead network, connecting our customers to the transmission system at grid exit points.

Support structures also support distribution transformers, network switches and third party assets such as streetlights, communication assets and road signs.

Box 5.1: Fleet Objectives and Strategy

As the majority of our overhead network is accessible to the public, effectively managing our overhead structure assets is critical in ensuring public safety, especially in urban areas. Appropriate performance from these assets is therefore essential for maintaining a safe and reliable network.

We have established the following objectives for the support structures asset fleet:

– Take all reasonable steps to ensure public, staff and contractor safety
– Within two years, all poles identified as needing replacement or refurbishment are being remediated within regulated timeframes
– By April 2020, return to full compliance with our five-yearly pole inspection and testing regime
– Safely minimise outages associated with planned work on structures.

Key strategies for achieving these objectives are:

– Short-term: reduce structure-related risks using a combination of refurbishment (where feasible and cost effective) and replacement, focussing on high criticality areas first. We will achieve this by targeting our testing programme (which drives renewals) to higher risk poles
– Medium-term: maintain acceptable fleet-risk by carrying out structure refurbishment and replacement based on the individual risk associated with each structure
– Ensure work packages enable contractor efficiency and minimise customer outage impacts, in particular, by undertaking inspections and testing by outage zone.

Our poles are constructed from wood (example photo on the right), concrete and steel. Life expectancies and degradation modes vary by type and location. For example, hardwood poles are of several different species and performance varies by species. These poles often lose cross section due to below ground rot, but some also split, peel, or suffer head rot. Common degradation modes for concrete poles are cracking and spalling of the concrete.

For new poles, our preferred type depends on the site and the loads that the pole is due to carry. We initially design for the use of pre-stressed concrete poles if possible[48] although availability of concrete poles can be a constraint.

We replace or reinforce degraded poles. Reinforcement is a cost-effective alternative to replacement which can significantly extend the life of a pole. Our reinforcement approach involves installing a steel truss driven deep into the ground next to the pole and secured with metal banding. Once reinforced, the pole health score is amended to reflect its increased remaining life.

48 While steel poles are stronger than concrete and potentially cheaper, the use of steel around other infrastructure must be taken into consideration. Hardwood poles are the most costly to purchase and to install (crossarm positions and holes must be prepared) but may be selected to meet specific strength characteristics.

Crossarms (example photo on the right) support overhead conductors. A crossarm assembly comprises one (or more) crossarms together with ancillary components such as insulators, binders and jumpers. Most of our crossarms are Australian hardwood, and there is a variety of insulator configurations. Crossarms typically reach end-of-life as a result of age-related cracking and loss of strength as the wood dries out, or because of rotting on the upper side due to moisture ingress.

Hardwood crossarms remain our preference, although we have installed galvanised steel crossarms on some new steel poles.[49] Components of the crossarm assembly (such as a broken insulator) are replaced through the corrective maintenance process. During the planning period we will undertake a programme of proactive crossarm replacements.

Population

Our 54,044 poles[50] are constructed from wood, concrete and steel. Table 5.3 summarises our population of poles by type. Wood poles currently make up more than half of the pole population. Historically, crossarms have been considered part of the pole asset and we have not retained separate population or condition data for them. We have begun to capture pole defect information more comprehensively as we improve our pole testing process. We estimate that we have an average of approximately 1.7 crossarms per pole (totalling approximately 94,000 assets).

Table 5.3: Pole Population by Material Type (as at 31 March 2018)

TYPE	POPULATION	PERCENTAGE
Hardwood	22,454	42%
Softwood	6,442	12%
Concrete	24,332	45%
Steel	816	2%
Total	**54,044**	**100%**

Age Profiles

Based on historical data, we estimate that our hardwood poles have an average life expectancy of about 60 years. Softwood poles generally have a considerably shorter average life and can deteriorate unpredictably. The charts below show that many of our wooden poles have exceeded or will soon exceed their expected life. Few concrete/steel poles have exceeded their 80 year expected lives.

49 Hardwood crossarms have several advantages over steel: they have a lower upfront cost and are non-conductive (lower public safety risk in the event of a failure).

50 This excludes consumer poles.

The age profiles below show the impact of our fast track pole programme (FTPP) carried out in 2017. As part of the programme we remediated (replaced or refurbished) approximately 3,000 poles. The charts reflect our preference to replace with pre-stressed concrete poles, where possible.

Many of the oldest poles on our networks will be replaced as part of a planned reconductoring project of the Waipori circuits in the early part of the planning period.

Figure 5.4: Poles Age Profile – Wood (as at 31 March 2018)

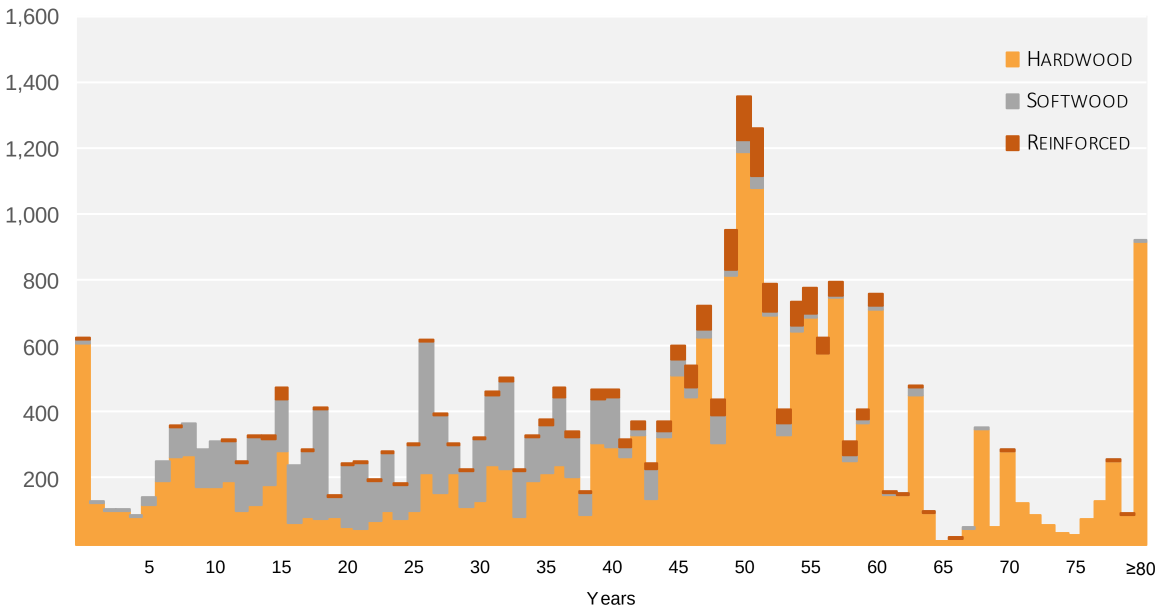
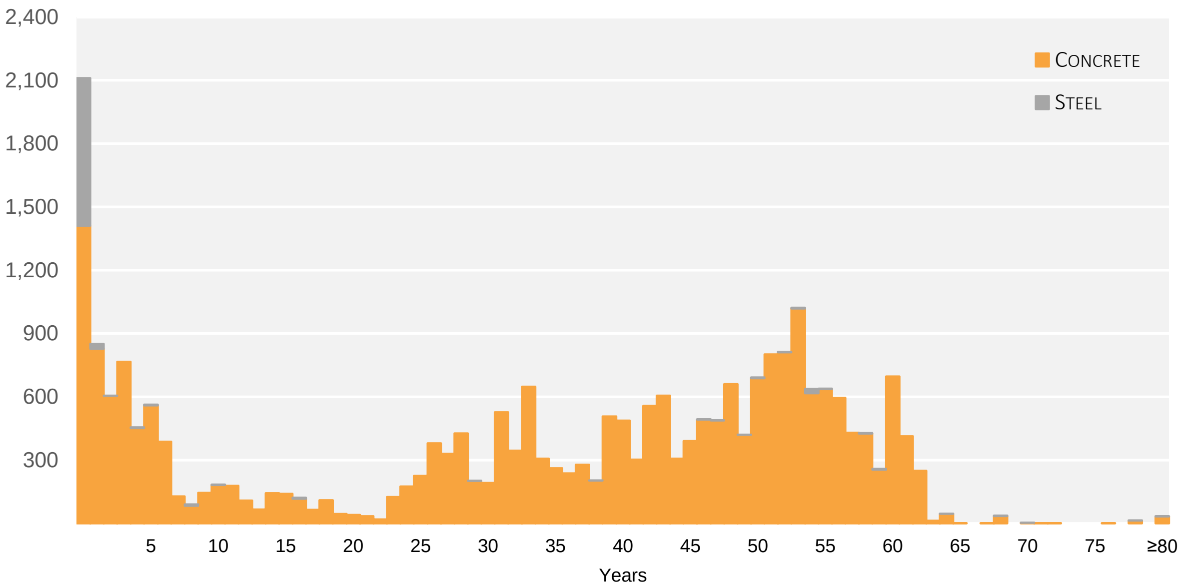


Figure 5.5: Poles Age Profile – Concrete and Steel (as at 31 March 2018)



We do not have a full set of crossarm population or age data due to their historical treatment as part of the pole asset. In all cases where a pole is replaced a new crossarm is installed, so many of our crossarms are the same age as the pole to which they are attached. However, some will be younger than the pole on which they are sited as their shorter life means that some will have been replaced during the life of the pole. Based on pole age profiles – and assuming most crossarms are the same age as the pole to which they are attached – we estimate that approximately 50% of our crossarms have exceeded their expected life.

We are planning to manage crossarms as a separate sub-fleet. Initially this involves creating the new assets in our systems, changing the condition assessment requirements for overhead structures to collect specific data on crossarm condition, and reporting on insulator condition by exception.

5.4.2. Condition, Performance and Risk

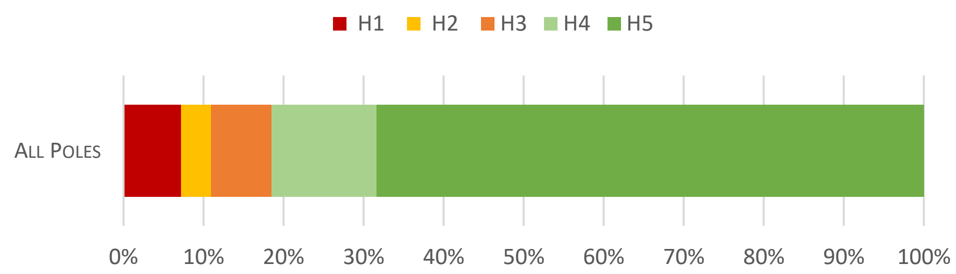
Managing the condition of our poles and crossarms is critical to meeting our asset management objectives for safety and network performance (refer Chapter 4). In the worst case, asset failure – particularly failure of a pole – could result in live conductor on the ground or injury caused by the falling asset. Pole or crossarm failure will also typically cause loss of supply.

Pole Asset Health

Asset health reflects the expected remaining life of an asset and provides a proxy for likelihood of failure that we use for renewals forecasting. Our current approach to calculating overall fleet asset health utilises a combination of condition (for poles that have been assessed within the current condition assessment cycle) and age (for those that are yet to be assessed). Pole end-of-life is defined as when the asset can no longer be relied upon to carry its mechanical load and the pole should be replaced. The age-based component of the model assumes expected lives of 60 and 80 years for wood and concrete poles, respectively.

Pole asset health using this approach is shown in Figure 5.6. Most poles classified as H1 are hardwood.

Figure 5.6: Poles Asset Health (as at 31 March 2018)[51]



Box 5.2: Investment Plans

To manage immediate and longer term risk associated with our overhead structure assets we are:

- increasing renewal volumes so that we replace or refurbish ~6,000 poles (with crossarms) and ~8,000 standalone crossarms over the next three years
- prioritising the testing and remediation of poles in high criticality (highly populated) areas.

Our 10 year plan includes $150 m for pole and crossarm renewals. By the end of the period, we expect that less than 1% of our poles will be classified as end of life (H1).

[51] Our asset health definitions are included in Table 5.1.

In recent years we fell well behind the level of replacements required to manage the health of our poles fleet and meet regulatory requirements.[52]

Following the fast track pole programme, we have maintained our pole testing and renewal programmes with the objective of returning the asset fleet to an acceptable level of health as soon as practicable. Although we are making good progress with our accelerated testing programme, at present approximately half of our poles have not been tested since July 2012. We expect that there remain a considerable number of wooden poles in poor condition warranting replacement or reinforcement.

As at 4 October 2018 we had a backlog of approximately 1,027 red tagged poles awaiting replacement. Even as we reduce the backlog, the ongoing assessments of pole condition will result in additional poles requiring replacement.

As described in Chapter 8, our forecast expenditure on poles makes provision to maintain our accelerated pole replacement and refurbishment programme for an additional three years, before returning to a steady state level of work. Pole replacements relating to several large reconductoring projects will also occur during the early years of the period. We have planned Capex of about $25m in RY19 for our support structures programme as a whole, reducing to about half that by the end of the planning period.

Crossarm Asset Health

At this time we are unable to provide a view on crossarm asset health. We believe that many of our crossarms have exceeded their expected life, but this does not necessarily mean they are in poor condition or that replacement is warranted. We are working to improve our understanding of crossarm health.

We are aware of an issue with Malaysian hardwood crossarms, which we have found to be less durable than the Australian hardwoods that we have primarily used. We believe that several thousand of these remain on our networks. Deteriorated crossarms will be captured as part of our pole inspection and testing programme. We intend to treat crossarms as a separate sub-fleet, requiring additional crossarm data to be captured going forward, including type, age, and condition.

As described in Chapter 8, our expenditure forecast for standalone crossarm renewals assumes that we will ramp up our renewal programme over the next two years – as we continue to compile data on the fleet – with a sizable renewals work programme continuing through to the end of the AMP planning period.

Asset Performance and Risks

Support structures, by their nature, create risks to public and personnel safety. For example, pole or crossarm failure causing a line to fall could result in electrocution or fire risk for people, property or livestock, either directly or indirectly (by livening houses, fences or other structures).

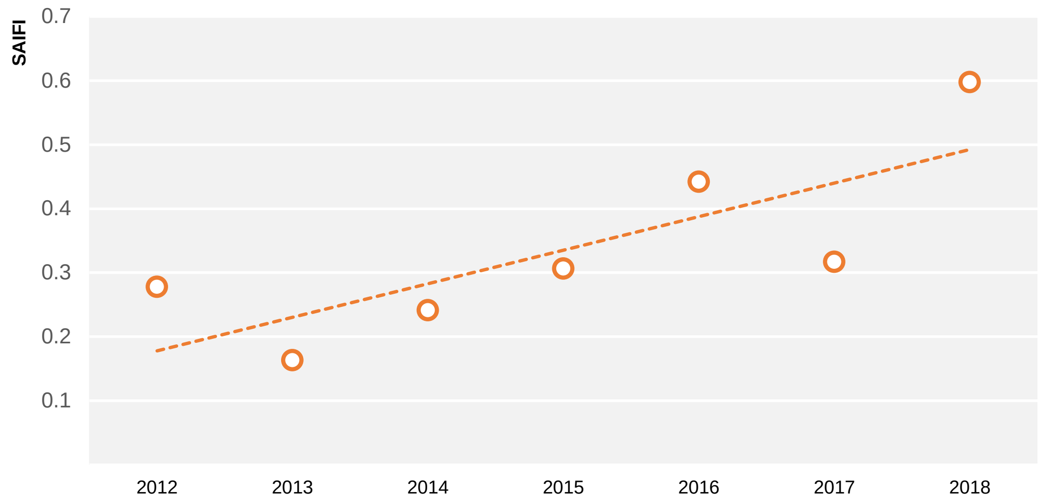
We have identified limitations in historical data about pole and crossarm failures. These limitations are primarily around the definitions of assisted and unassisted failures and the process for differentiating

[52] These requirements are set out in the Electricity (Safety) Regulations 2010, and summarised in Box 5.3.

between them. For example, failure of a structure caused by wind could be considered unassisted (if the wind strength is within design loads), or assisted (otherwise).

Due to a lack of historical data on unassisted failures specifically, we have used (un-normalised) SAIFI attributable to our overhead structures as a proxy for the total number of failures (Figure 5.7).

Figure 5.7: Pole-driven SAIFI as a proxy for asset performance



The trend line indicates an increase in structures-related SAIFI in recent years. On average, approximately 10% of total unplanned SAIFI is due to structures. We plan to improve our classification of pole failures so that we can differentiate the types of failure.

Box 5.3: Pole tagging

The Electricity (Safety) Regulations 2010[53] require that:

- If overhead structures are found to be incapable of supporting structural design loads, the owner of the structures must mark them, and repair or replace them within 12 months of them being identified as such.
- If overhead structures are found to be at risk of failure under normal structural loads, and there is a risk of injury to any person or damage to property other than that of the owner of the line, the owner of the structures must mark them, and repair or replace them within 3 months of them being identified as such.

Industry practice is to mark the structures by attaching an orange tag (in the first case) or a red tag (in the second case). In addition to these, we currently attach blue tags to poles where these have been identified with any of a range of defects requiring repair or component replacement, for example, crossarm or other pole top defects, or missing signage. Our timeframe for remediating blue tagged poles is currently 24 months, but we are re-evaluating the value provided by the blue tag process, and may discontinue this practice.

53 Clauses 41(3) and (4).

5.4.3. Maintenance Approach

Poles and crossarms do not require any routine mechanical or electrical maintenance. As a result, our maintenance approach focuses on using inspections, condition assessment, defect management and fault repairs to retain assets in service until it is no longer safe or cost effective to do so.

Inspections

Our cyclical pole inspections are currently prioritised on the basis of public safety criticality.[54] In response to findings from recent inspections and condition assessments and feedback from WSP[55], we are also – in addition to our normal inspections – undertaking 'drive-by' inspections of all poles in high public safety criticality areas that have not yet been inspected and tested during the current cycle.

All poles need regular inspection as they may be damaged or compromised by a third party. One of the most common causes of pole failure is third party vehicle damage. We aim to undertake ground-based inspections of our pole assets (at least) every five years, in addition to some Corona Cam inspections.

Condition assessment

Our other preventive maintenance task in relation to poles is condition assessment and testing, which is generally undertaken in parallel with inspections. The nature of wooden poles makes condition assessment difficult. Deterioration is often internal and/or below ground. Some testing techniques require removal of concrete around poles, but this weakens them and can allow water ingress and accelerate deterioration.

We aim to undertake condition assessments of pole structures at least every five years. Historically, our primary method for assessing a pole's structural integrity was the traditional 'dig probe and hammer testing' method. Together with visual inspection focussing on above ground condition – including crossarms and insulators/hardware – this enabled us to assign a condition score to each pole asset.

Recognising limitations with the traditional method, we considered alternatives for testing wooden poles, settling on Deuar Mechanical Pole Testing (MPT) which has been in place since 2015. This technique is also supplemented by visual inspection. We continue to use a tailored traditional approach for concrete and steel poles, for which Deuar cannot be applied. The outputs of our condition assessment regime are structural integrity and overall condition ratings for each asset, together with the identification of any defects.

Once the structural integrity of a pole has been determined and we have completed a visual assessment, a standardised decision-making process determines whether pole replacement or reinforcement is warranted, whether crossarm replacement is required, and the timeframe for completion – ranging from 3 to 36 months. These intervention timeframes are consistent with the requirements of the Electricity (Safety) Regulations 2010.

Approximately half of our poles have not been tested since 2012. We are running an accelerated testing programme over the next two years. By April 2020, we will return to full compliance with our five yearly

[54] In time we plan to expand criticality to also include network impact, such as number of ICPs lost.

[55] As part of its investigations, WSP carried out drone-based condition assessment of both the pole and crossarm(s) on a statistically representative sample of ~800 poles across our Dunedin and Central Otago networks, encompassing all voltages. Information from this survey has been taken into consideration, to the extent available, in planning for this fleet.

inspection regime. In the interim, our approach to ensure that renewals and refurbishments are prioritised on the basis of public safety criticality, involves:

- Focussing on testing wood poles that have not been tested within the current five year cycle first. We further prioritise within this group on the basis of public safety criticality – by identifying clusters of poles located near schools, arterial road routes, etc. – and group poles for testing by outage zone. This ensures that renewals and refurbishments are prioritised based on safety, and the work minimises disruption to customers.
- Testing concrete poles only once all wood poles have been tested, based on their longer expected lives and lower risk.

Box 5.4: Deuar Pole Testing

Deuar MPT is a mechanical loading and deflection testing method for determining the below-ground strength of each pole.

We started using Deuar MPT in 2015, following a review and evaluation of several potential pole testing methods. It was selected based on field trials and prior evidence. This method has been used and tested internationally for over a decade.

It employs a chain at the pole base plus a portable hydraulic arm that leverages off the chain to apply a mechanical bending moment on the pole. Instruments affixed to the pole record the bending during the application and removal of force. Through mathematical modelling, Deuar MPT estimates the current pole strength as a percentage of design load. It is a relatively time consuming method of testing, but unlike traditional methods – which are relatively subjective – provides an objective, empirical measurement of pole strength. It cannot currently be used for concrete poles or those in certain locations.

We plan to undertake forensic testing of a number of end-of-life poles later this year. Prior to break testing the poles we will test them with Deuar MPT, the traditional method, and other selected tools (in collaboration with other EDBs). This may result in further changes to our testing regime.

We have processes in place to manage the immediate situation where testing finds that the structural integrity of a pole is below normal working load. For example, if the Deuar pole status is 'Failed Initial Test', the overhead line inspector may not move on from the site until a competent and approved employee arrives on site to determine the appropriate action.

Corrective and Reactive Maintenance

Defects may be identified during visual inspections. The associated timeframe for remediation depends on the nature of the defect and criticality of the structure.

Fault response may be required in the event of a pole or crossarm failure, for example, due to vehicle damage or extreme weather. Alerts may be via fault indication in SCADA, or reports from emergency services or members of the public. We may need to temporarily prop a damaged pole to enable the line to remain energised while preparation is made to replace the damaged pole, thereby minimising the effect of any outage.

5.4.4. Renewals and Refurbishment

Table 5.4 provides a summary of our renewal approach for overhead structures.

Table 5.4: Summary of Overhead Structures Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition (prioritised by public safety criticality)
Medium term forecast (renewal volume)	Asset health, planned reconductoring projects
Cost estimation	Volumetric

Investment Drivers

The main drivers of Capex investments in pole assets are:

- Asset health (age and condition/structural integrity)
- Public safety criticality.

We replace or reinforce (refurbish) poles based on as-found structural integrity and above ground condition of each individual pole. Refurbishment is used in preference to replacement if it is feasible, cost effective and expected to return strength to design standard, given the type, condition, location, and above-ground condition of the pole.[56] Crossarm assemblies are always replaced when a pole is replaced, but may also be replaced separately based on identified defects. We expect separate replacement of crossarm assemblies to be a relatively large programme of work over the planning period. The need for this programme of work is supported by the risk review undertaken by WSP.

Inspections are prioritised on the basis of public safety criticality, and resulting replacements and refurbishments on the basis of condition and criticality.

Additional pole investments are driven by reconductoring projects, where existing poles are nearing end-of-life or will not have the structural integrity to carry the new conductor. It may also be cost-effective to bring forward pole replacements in some instances so they can be combined with other works to minimise outage impacts, optimise land access and maximise contractor efficiency. In some instances, the need to replace a crossarm may bring forward pole replacement. Economic analysis can be used to determine when this is appropriate.

In some cases, renewal of an entire line provides an opportunity for efficiency. This is the case with the Waipori subtransmission lines replacement project which will replace 1,900 poles with fewer than half that number.

Forecasting approach

Annual pole and crossarm replacement and refurbishment volumes are forecast based on asset health, and reconductoring project needs.

The forecast uses unit rates based on historical costs adjusted for anticipated project /site complexity. Unit rates assume the use of pre-stressed concrete poles, and include the cost of replacing full crossarm

56 We cannot reinforce poles that are encased in concrete or which have certain access issues, or those which have deteriorated beyond the condition at which this is a feasible option.

assemblies, but excludes the cost of other hardware such as air-break switches, fuses and transformers, which are included in other forecasts.

5.5. OVERHEAD CONDUCTORS

This section describes our overhead conductor fleet and summarises our management plan for these assets.

5.5.1. Overview of Fleet

Our fleet plan for overhead conductor is broken down into the following sub-classes:

- Subtransmission overhead conductors (33/66 kV)
- Distribution overhead conductors (6.6/11 kV)
- Low voltage (LV) overhead conductor (230/400 V).

Overhead conductor is a core component of our network. Conductors and overhead structures together comprise our extensive overhead network, connecting our customers to the national transmission system.

Subtransmission lines convey electricity from Transpower's GXPs to our zone substations, while distribution and LV lines carry the electricity from zone substations to our customers. The conductors fleet also includes conductor hardware such as joints, spacers and dampers and armour rods.

Box 5.5: Fleet Objectives

The performance of our overhead conductor assets is essential for maintaining a safe and reliable network. As the majority of our overhead network is accessible to the public, management of these assets is also critical in ensuring public safety, especially in urban areas.

We have established the following objectives for the Overhead Conductors asset fleet:

- No injuries to workers or public as a result of conductor failure
- No third party damage/fires as a result of conductor failure
- High quality asset information supports condition-based asset health models
- Systematic analysis of failures provides reliable feedback to inform asset planning decisions
- Structured and reliable fault data supports establishment of performance KPIs.

Key strategies for achieving these objectives are:

- Reduce risk by focusing on high criticality areas first
- Undertaking forensic tests on sections of conductor that have had faults
- Develop and implement improved inspection and data gathering methodologies.

We use a variety of conductor types across the range of voltages. No.8 Wire and copper were the main types used until about the mid-1960s when All Aluminium Conductor (AAC) and Aluminium Core Steel Reinforced (ACSR) type conductors became the preferred types. We recently started using All Aluminium Alloy Conductors (AAAC) in some situations.

No. 8 steel wire is a single strand, small diameter galvanised wire. As a result, it tends to be less durable than other conductor types and can be prone to sudden failure. Copper and No.8 Wire are susceptible to annealing and fretting or chafing.[57] Copper has good corrosion resistance so is less affected by proximity to the coast. However, it is more affected by fatigue caused by the flexing of conductors near the insulators particularly in wind-prone areas, causing brittleness over time. Twisted copper conductor is particularly brittle and failure prone.

ACSR has become the most used conductor type on our networks at subtransmission and distribution voltages. ACSR conductor consists of an inner core of solid or stranded steel, and one or more outer layers of aluminium strands. This construction gives it a high strength-to-weight ratio making it ideal for long spans, so it is widely used in rural parts of our networks. However, the steel core that gives ACSR conductor its strength also makes it more vulnerable to corrosion in coastal areas. Corrosion is reduced by galvanising or grease coating the core, but this increases the weight of the conductor.

Clashing of adjacent conductors and foreign object strikes (vegetation, birds, etc.) can also cause conductor to suffer mechanical damage, leading to a significant loss of tensile strength.

Population

We have a total of 5,210 km of overhead conductor, made up of 526 km at subtransmission voltages, 2,313 km at distribution voltages and 2,371 km of low voltage and street lighting circuits. The majority of subtransmission and distribution conductor is modern ACSR type, although a significant proportion of copper remains in use (as well as No.8 Wire at distribution voltages). Low voltage conductor is primarily copper and Aluminium types.

Approximately 75% of our overhead subtransmission conductor and 70% of our distribution conductor is located in the Central Otago network.

Table 5.5: Overhead Conductor Population by Type (circuit length, km), as at 1 June 2018

TYPE	SUBTRANSMISSION	DISTRIBUTION	LOW VOLTAGE	LV STREETLIGHTING[58]
ACSR	392	1,514	13	0
Copper	128	526	698	1,322
Aluminium	5	34	335	4
No.8 Wire	0	239	0	0
Total length (km)	**526**	**2,313**	**1,045**	**1,326**

Age Profiles

The life expectancy of conductor assets is dependent on the type, location, and size of the conductor. For forecasting purposes we have developed conductor expected lives, as set out in Table 5.6, based on publicly available data from peer utilities.[59] Corrosion is a key driver of conductor degradation; we took Transpower's corrosion zones into account in determining expected lives.[60] For example, the life

57 Annealing is a reduction in the minimum tensile strength through heating and slow cooling. Fretting and chafing is caused by conductor swing causing wear and primarily affects homogenous conductor types. Chafing can also occur between the conductor and the binder which connects it to the insulators.

58 This does not differentiate between dedicated/non-dedicated streetlighting.

59 Expected lives do not apply to conductor with an identified type issue which may have a considerably shorter life.

60 Information on development of corrosion zones is included in Transpower RCP2 fleet strategies. Transpower divided their network into six zones ranging from Benign through to Extremely Corrosive.

expectancy of ACSR conductor used in our renewals forecasts ranges from 28 to 74 years, where the low end of the range reflects small diameter conductor located within 500 m of the coast.

This is a relatively simplistic approach and we are investigating methods to refine these ranges using conductor sampling/forensic analysis, and analysis of performance data from within our networks. Other New Zealand utilities are also undertaking forensic work of this type to improve understanding of conductor degradation.

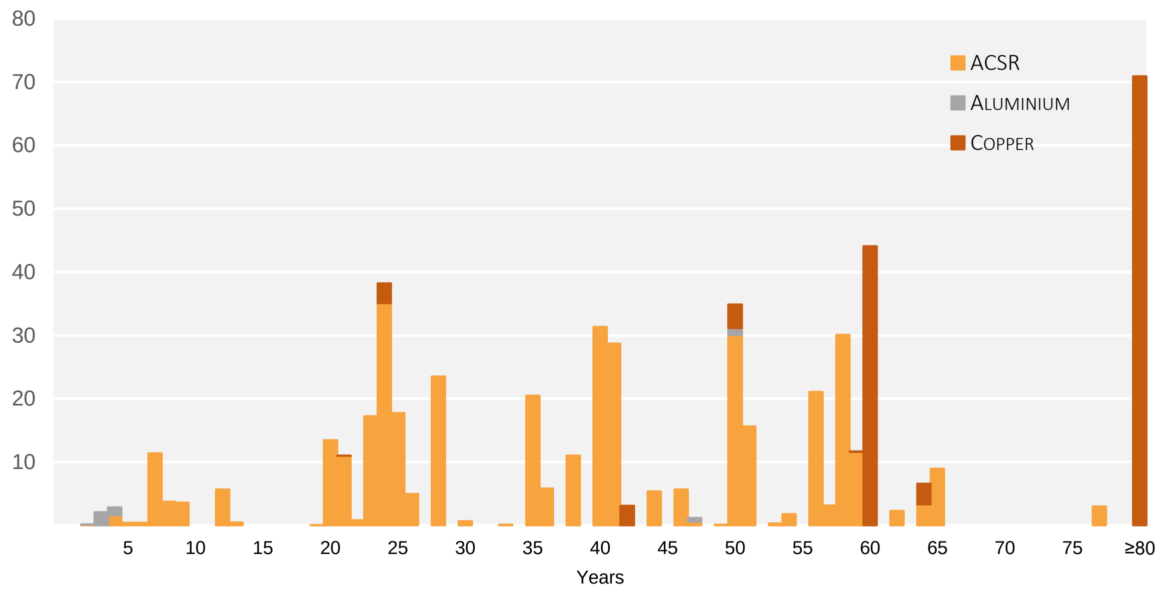
Table 5.6: Overhead Conductor Maximum Practical Life (MPL)

TYPE	CONDUCTOR SIZE (MM)	WITHIN 500 M OF COAST	500 M – 5 KM OF COAST	> 5 KM FROM COAST
Aluminium	<100	77	93	110
Aluminium	≥100	87	103	120
ACSR	<100	28	43	64
ACSR	≥100	38	53	74
Copper	<100	55	57	80
Copper	≥100	65	77	90
Steel	<100	48	59	75

The figures below show age profiles of our overhead conductor sub-fleets. The weighted average age of subtransmission conductor is 49 years. A significant amount of our subtransmission conductor, primarily copper, will exceed its expected life in the near future, or has already. The oldest copper conductor is on the Waipori A, B and C lines which are scheduled for replacement.

Failure of conductor hardware is a common cause of conductor failure. We do not currently collect separate data on conductor hardware, including joints, spacers and dampers. We plan to start collecting specific data on these assets – including location, type and age.

Figure 5.8: Overhead Conductor Age Profile by Circuit Length (km) – subtransmission (as at 1 June 2018)



A significant volume of our distribution conductor has already exceeded its expected life. Distribution conductor overall has a weighted average age of 44 years. The copper and No.8 Wire populations are much older, with a weighted average age of 57 years. These types are also less durable than other types, so we are prioritising their replacement.

Figure 5.9: Overhead Conductor Age Profile by Circuit Length (km) – Distribution (as at 1 June 2018)

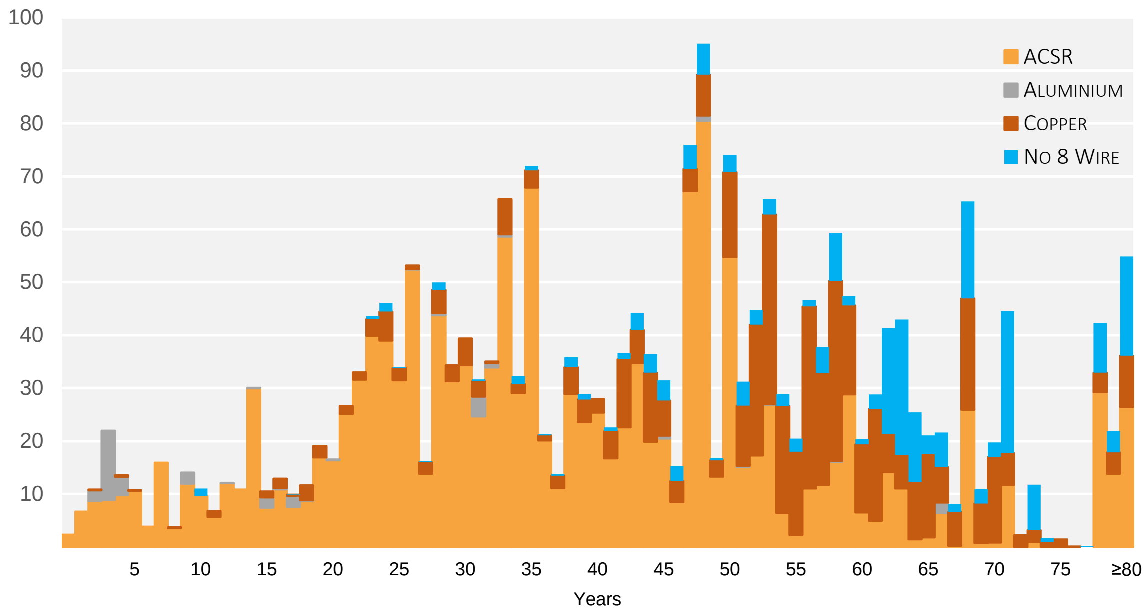
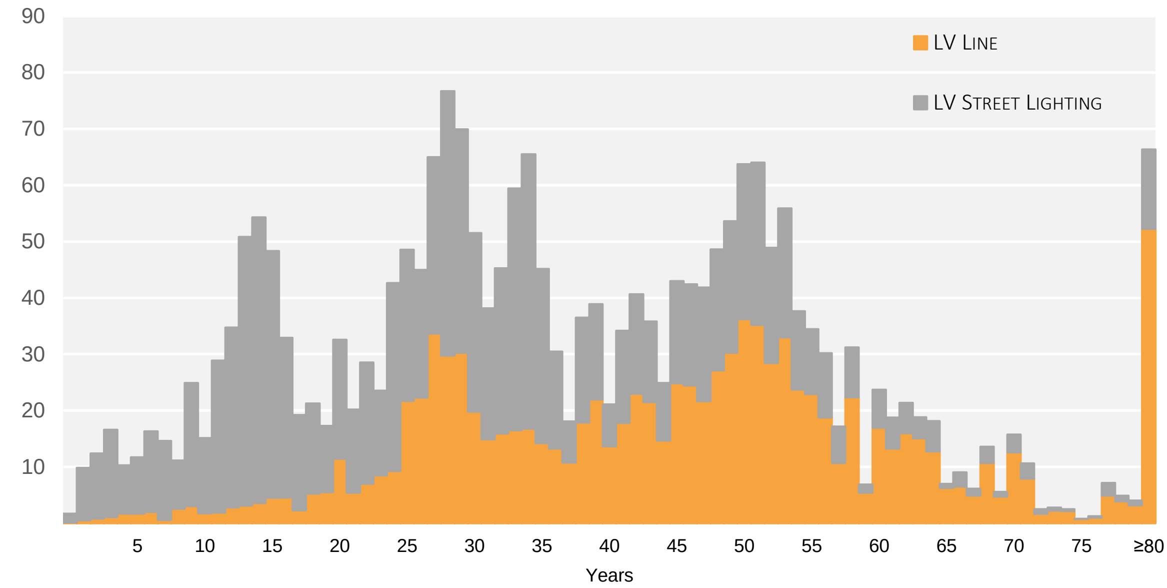


Figure 5.10: Overhead Conductor Age Profile by Circuit Length (km) – Low Voltage (as at 1 June 2018)



5.5.2. Condition, Performance and Risk

Managing the condition of our overhead conductor assets is critical to meeting our safety and network performance objectives (refer Chapter 4). In the worst case, asset failure could result in live conductor on the ground. Conductor failure will also typically cause loss of supply.

To minimise public safety and performance risks we aim to proactively repair and replace overhead conductor prior to failure.

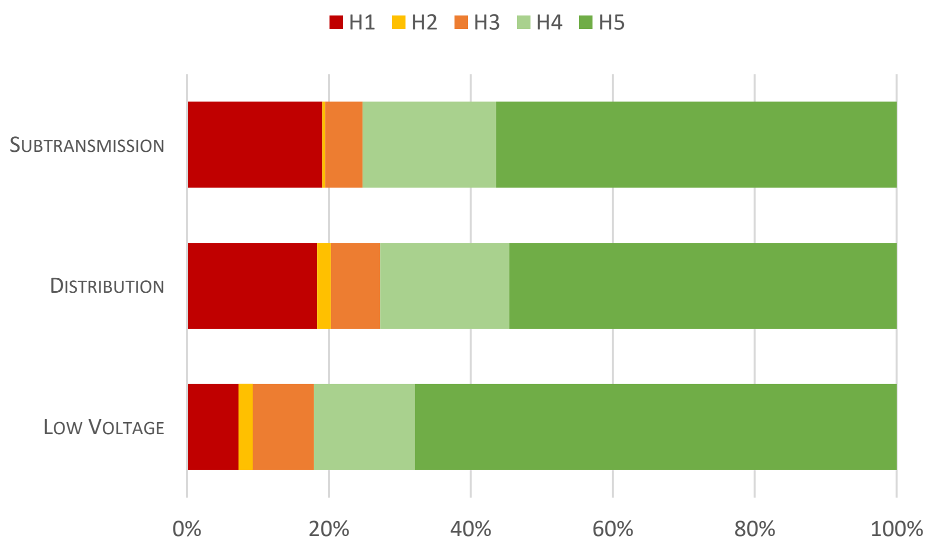
Asset Health

Age is a key driver of conductor degradation, along with proximity to the coast and cross-sectional size of the conductor. We currently use simple age-based asset health models for forecasting renewal needs for our conductor fleets – with MPLs as described above – though we plan to develop these to account for additional factors. These models will also enable us to better understand and manage the risk associated with our conductor assets.

Remaining life is estimated for each asset by subtracting current age from MPL; the results are aggregated to provide a view of overall fleet health. Figure 5.11 shows the asset health of our conductor sub-fleets.

To support development of prioritised renewal work programmes, we are also developing our understanding of actual conductor condition. This will involve more detailed condition assessment, together with conductor sampling.

Figure 5.11: Overhead Conductor Asset Health (as at 31 March 2018)



Box 5.6: Investment Plans

To manage risk associated with our conductor assets we are:

- replacing 256 km of conductor over the next three years, prioritising the three Waipori 33 kV lines, reducing subtransmission end of life (H1) conductor to less than 1%
- replacing small copper and No.8 wire (distribution) conductor in high criticality areas. We will align this work with our pole programme. This has a benefit of reducing the number of planned outages required.
- renewing/modernising our protection relays to help achieve safe isolation of failed lines.

Our 10 year plan includes $55 m of renewals. By the end of the period, we expect the levels of H1 conductor across all voltages to be less than 1%.

Two of the three Waipori subtransmission circuits are classified as H1. These are scheduled for replacement in the near term.[61] Overall, we expect that approximately 20% of our conductor will require replacement over the next ten years (H1-H3) on the basis of age. A small volume of additional replacements will be required for other reasons as discussed below.

Chapter 8 sets out our forecast expenditure on overhead conductor renewals, which totals about $5-6 million per annum over the planning period. In the earlier years of the planning period our focus is primarily on known large (subtransmission) reconductoring projects (the Waipori Line Upgrade, Cape Saunders Voltage Conversion and the Port Chalmers to Peninsular Harbour Crossing). At the same time we will be ramping up our replacement programmes for poor condition distribution and LV conductor, consistent with the asset health chart shown above. As with our crossarms renewal work, this part of our work programme relies on collecting and compiling condition data for these sub-fleets, sufficient to support detailed planning. In the case of LV conductor replacement, our initial focus will be on poor condition line in higher safety criticality areas.

Asset Performance and Risk

Overhead conductors, by their nature, create risks to public and personnel safety. Much of this risk can be mitigated to a large extent by actions such as managing asset condition, controlling vegetation, and utilising asset information. Some examples of risk are:

- lines falling causing fires affecting buildings, forests and crops. The trigger may be condition-related or caused by vegetation or third party damage, and presents a significant safety risk
- low hanging conductors, which pose a contact risk to people, property, and livestock.

These risks apply across all voltages to some extent. Protection systems with switchgear at zone substations protect conductors and isolate supply when faults occur. Other fault discrimination is employed along distribution feeders by way of reclosers, sectionalisers and fusing.

We have carried out a LIDAR survey of road crossings in the Central network to determine the locations of low spans for remediation. However this is an issue that will continue to arise as a result of underbuilt driveways and road resurfacing.

Our subtransmission lines are aging but line failures are rare, largely due to its heavier, more robust construction. However, we have had a small number of conductor-related outages on our 33 kV and 66 kV lines in recent years, most of which related to failed tie wires.[62]

We have seen a much larger number of distribution and LV conductor failures. The main causes of failure are vegetation touching lines, wind and equipment deterioration. The single strand conductor types – copper and No.8 Wire – are less durable and more prone to failure than other types, and we plan to focus on replacement of these types to mitigate risk. In the absence of accurate condition information, we take failure trend information into consideration when planning renewals.

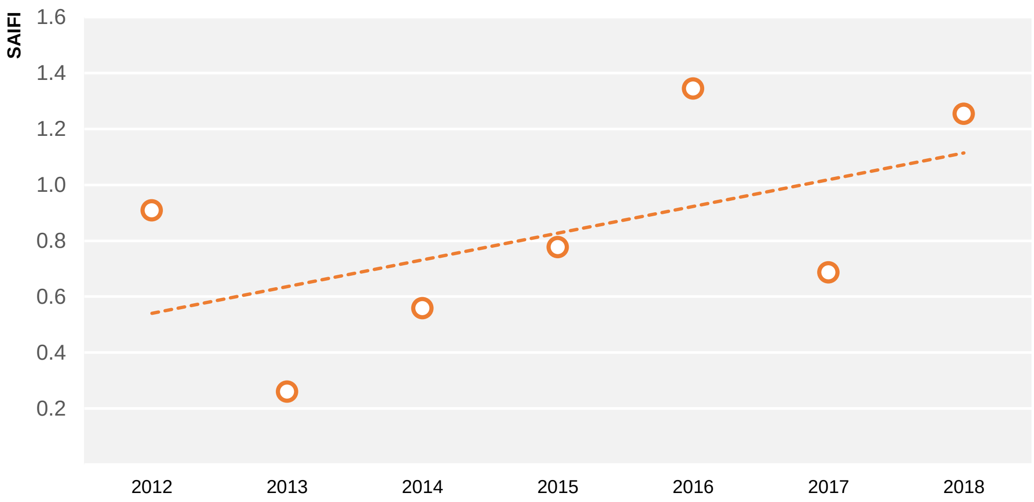
As with our pole failures data, our conductor performance data has a number of limitations. In particular, the process for differentiating between assisted and unassisted failures prevents us from separately reporting on unassisted failures. Instead Figure 5.12 shows the SAIFI attributable to

[61] We also plan to replace the third Waipori line – an additional 31km – as part of the overall project.

[62] Tie wire binds the conductor to the insulator. We are replacing tie wires with distribution ties on new installs.

overhead conductor, as a proxy for total number of failures. The trend line indicates an increase in conductor-related SAIFI in recent years. On average, 25% of unplanned SAIFI relates to conductor failures. While we do have concerns regarding the accuracy of this data, the magnitude of the issue supports a focus on our overhead network over the planning period. We plan to improve our classification of conductor failures so that we can better differentiate the types of failure. We also plan to restructure conductor asset data to record joint locations, span length, termination data and other component information to improve our understanding of unassisted failures in future.

Figure 5.12: Overhead Conductor Performance



5.5.3. Maintenance Approach

Conductor assets require little physical maintenance work, and no mechanical or electrical maintenance. As a result, our maintenance approach focuses on inspections and condition assessment, defect remediation and fault response to retain the assets in service until it is no longer safe or cost effective to do so.

Preventive Maintenance

Our primary maintenance tool to support this approach is condition monitoring. Inspections and condition assessments focus on identification of defects, such as broken strands, clashing, bulges, or tree impact. Severe or significant degradation or damage may be managed by replacement of a conductor section.

We do not currently collect condition data 'scores' for overhead conductor, but are considering how we might do this in future.

Table 5.7: Overhead Conductor Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
Subtransmission	Ground and/or air inspections	Identify and prioritise potential defects and vegetation infringements. Collect condition data for replacement planning	Annually
Subtransmission, distribution and LV (with pole inspections)	Detailed condition assessment	Assess condition of conductor, in conjunction with pole condition assessments.	Five-yearly

The nature of overhead conductor means that the accuracy that can be achieved through visual condition assessment is limited. Conductor sampling will help to improve our understanding of asset condition.

Corrective Maintenance

We schedule repairs to remediate defects, or may undertake diagnostic testing to find the source and/or magnitude of a problem. Many conductor defects are managed by replacing components such as joints.

Table 5.8: Overhead Conductor Corrective Maintenance

SUB-FLEET	ACTIVITY	PURPOSE
Subtransmission	Thermographic inspection	Identify high resistance joints, on request
	Acoustic testing	Identify and prioritise potential defects, on request (e.g. external parties, such as in relation to broadcasting complaints)
	Sampling	Determine as-found condition of conductor, on request
	Corona testing	Identify defects on insulators and conductor ties to insulators
All	Defect repairs	Repair defects to meet safety and service obligations, such as replacing joints, armour rods and binders

Reactive Maintenance

Fault response may be required in the event of an overhead conductor failure, to locate the issue or make the area safe. Reactive maintenance activities include fault patrols to identify fault location, and first response work to make a site safe following a failure. Alerts may be received via fault indication in SCADA, or reports from emergency services or members of the public.

5.5.4. Renewals and Refurbishment

Table 5.9 provides a summary of our renewal approach for overhead conductors.

Table 5.9: Summary of Overhead Conductor Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition and criticality
Medium term forecast (renewal volume)	Asset health
Cost estimation	Tailored for major projects, otherwise volumetric

Capex Investment Drivers

The key drivers of conductor replacement are asset health (age/condition) and public safety criticality.

Our focus during the planning period is on replacing end-of-life conductor at subtransmission and distribution voltages. These work programmes will focus on the aged and lower durability copper and No.8 wire types, with works prioritised on the basis of condition and criticality.

The high criticality areas for conductor coincide with those for poles and therefore our conductor replacement prioritisation work can be effectively implemented as work packages with the pole remediation programme.We also plan to replace several distribution circuits on the basis of condition, and address low span sections to mitigate the associated safety risk.

Forecasting Approach

Our forecasts focus on managing the risk associated with aged and poor condition subtransmission and distribution conductor sub-fleets. We currently forecast renewal needs based on age (as a proxy for condition), conductor type, and location, combined with the volume of identified low span renewals.

We use a volumetric method for forecasting the majority of our conductor replacement. Unit rates are based on recent historical costs for such projects. For major projects such as replacement of the Waipori circuits we have developed cost estimates taking into account project-specific factors.

5.6. UNDERGROUND CABLES

This section describes our underground cables fleet and summarises our management plan for the fleet.

5.6.1. Overview of Fleet

Our fleet plan for underground cables is broken down into the following sub-classes:

- Subtransmission cables (33/66 kV)
- Distribution cables (6.6/11 kV)
- Low Voltage (LV) cables (230/400 V)

This fleet excludes cable located within zone substations.

Underground power cables convey electricity between substations or from substations to our customers. This fleet also includes cable joints, pole terminations and other ancillary equipment.

Box 5.7: Fleet Objectives

The performance of these assets is essential for maintaining a safe and reliable network. Cables are not readily accessible by the public and have lower safety criticality, but may be damaged and exposed to the public by excavation. The reliability impact of cable faults can be greater than overhead conductor due to the longer repair times.

We have established the following objective for the Underground Cables asset fleet:

– Maintain the failure rate of cable assets at or below 0.1 per 100 km per year (excluding LV).

Key strategies for this fleet are:

– Remove all potheads by 2028

– Reduce risk by focusing on high criticality areas first.

Relative to overhead conductor, cables are better protected against weather and other conditions, but they are susceptible to insulation deterioration. However, provided the cables are installed properly it can take many years for insulation to deteriorate to the point where faults occur. Third party damage is a significant cause of issues for distribution and LV cables (excavation). Other common failure modes are splice, and termination and joint failures.

Population

We have 2,094 km of underground cable, close to 30% of total circuit length. Our subtransmission cable network uses gas and oil-filled, Paper Insulated Lead Covered (PILC), and Cross-Linked Polyethylene (XLPE) cable. Our distribution and LV networks use PILC, XLPE and polymer insulated cable.

Table 5.10: Underground Cable Population (as at 1 June 2018)

CABLE TYPE	SUBTRANSMISSION (KM)	DISTRIBUTION (KM)	LOW VOLTAGE (KM)[63]
Gas-filled	36	-	-
Oil-filled	25	-	-
PILC	11	430	40
XLPE	21	615	809
Polymer Insulated	-	-	107
Total	**93**	**1,045**	**956**

PILC has been used internationally for over 100 years, and manufactured in New Zealand since the 1950s. It uses paper insulating layers impregnated with non-draining wax. The cable is generally encased in a waterproof lead sheath covered in wrapped and tar-impregnated fibre material, PVC or polyethylene. PILC cables have a good performance record in the industry, though obtaining cable jointing expertise for this cable type is becoming problematic.

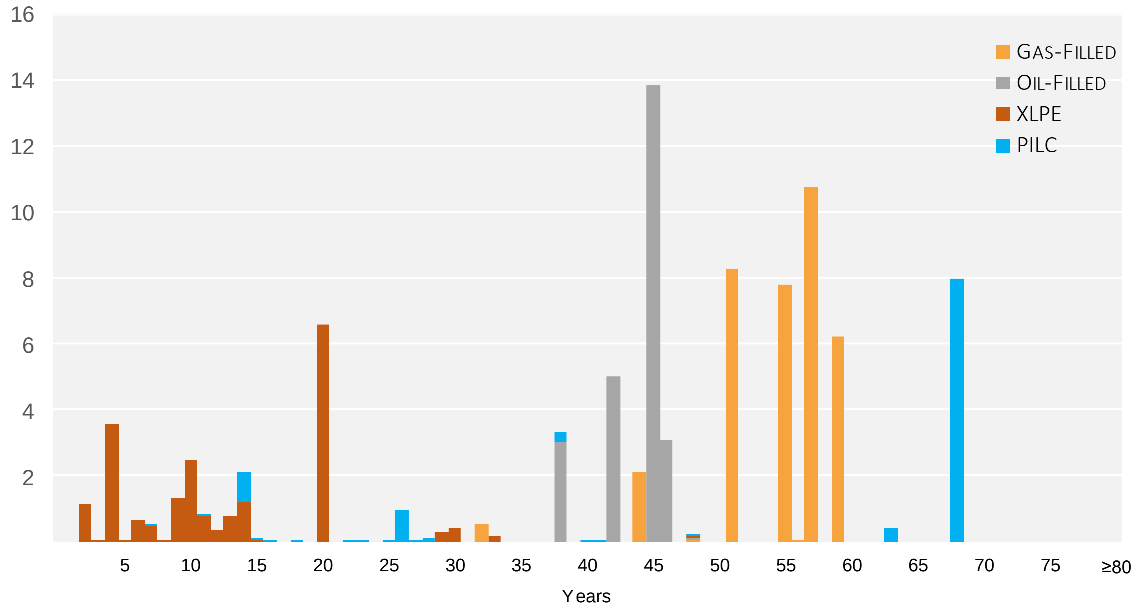
First generation XLPE cable which was installed in the 1960s and 1970s (subtransmission) is known to fail prematurely due to water-treeing causing the insulation to break down. The second (current) generation of XLPE has a treeing-retardant added during construction to extend its viable life. XLPE cable is now the industry standard and is generally used for new construction.

[63] This does not include streetlighting circuits

Age Profiles

The expected useful life of most PILC subtransmission and distribution cable is 80-100 years. We expect XLPE cable to last 45-60 years.

Figure 5.13: Underground Cable Age Profile by Circuit Length (km) – Subtransmission (as at 1 June 2018)



Most of our subtransmission cable was installed during the period 1960-80; our gas and oil-filled cable – the preferred types over that period – have weighted average ages of 54 years and 44 years, respectively. Our oldest cable is the PILC type. All first generation XLPE subtransmission cable has been decommissioned.

Figure 5.14: Underground Cable Age Profile by Circuit Length (km) – Distribution (as at 1 June 2018)

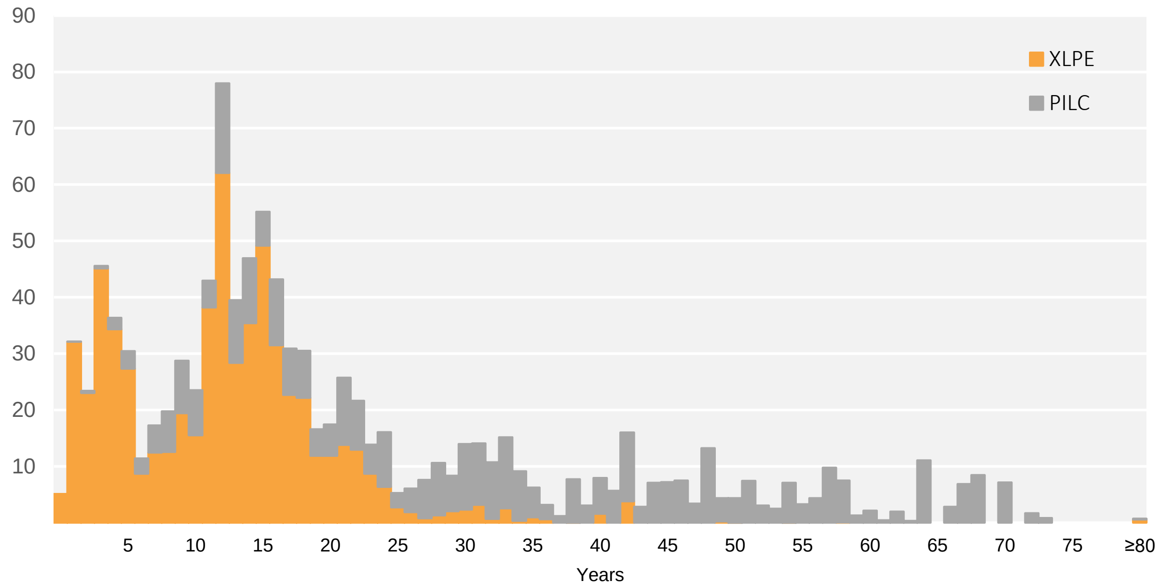
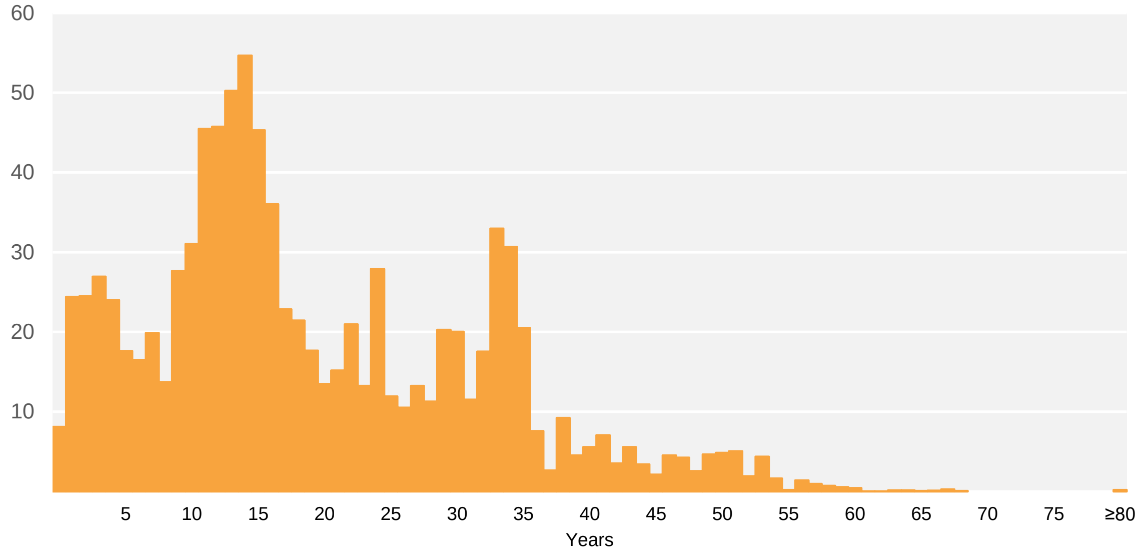


Figure 5.15: Underground Cable Age Profile by Circuit Length (km) – Low Voltage (as at 1 June 2018)

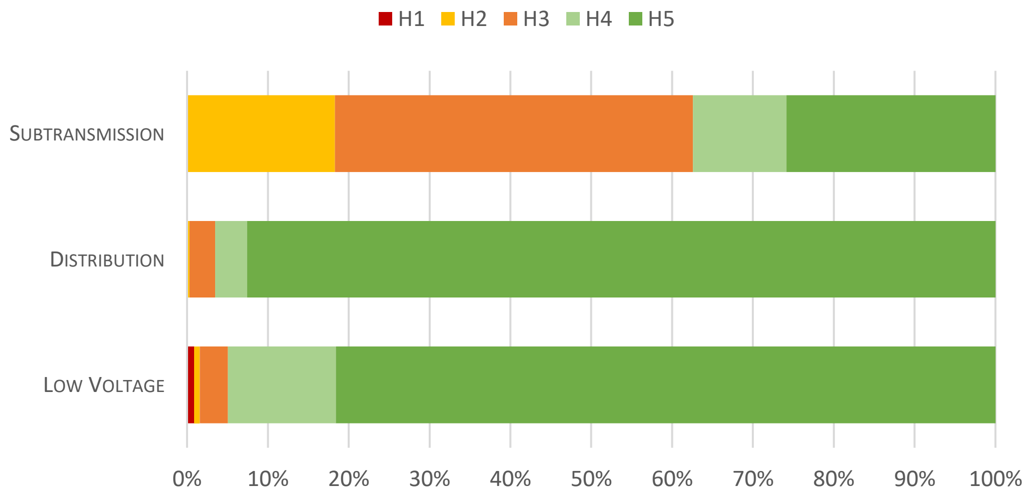


Our distribution and LV cable sub-fleets are considerably younger than our subtransmission cable. Some first generation XLPE remains in service on the distribution network (Figure 5.14); we are monitoring the condition and performance of this cable in light of its expected shorter life.

5.6.2. Condition, Performance and Risk

Managing the condition of our underground cable assets is important for meeting our performance objectives. Cable is protected against weather and other conditions that can affect our overhead lines, but it is susceptible to insulation deterioration. Terminations and cable risers are exposed to the elements and foreign interference which may cause accelerated aging. In general, our cable assets perform well, though faults on our aging subtransmission cable are increasing.

Figure 5.16: Cables Asset Health (as at 31 March 2018)



We define end-of life for underground cables as when the asset can no longer be relied upon to operate reliably and without environmental harm. We forecast renewals using a combination of age and known type issues (described below). Aged PILC and gas-filled pressurised subtransmission cable have an asset health score of H2, while oil filled cables have a score of H3 (3-10 year expected remaining life). Figure 5.16 shows the asset health of each of our cable sub-fleets.

As described in Chapter 8, our forecast expenditure on cable assets includes several focus areas. The majority of expenditure is on poor condition subtransmission cables, with this work weighted towards the start of the planning period. We have a programme to replace all remaining cast iron potheads over the period; this work will be carried out opportunistically when these are de-energised for other work such as pole, conductor and cable replacements. The other main components of the forecast are works to replace PILC distribution and LV cables in line with asset health. As cable assets are mostly underground, failure represents minimal safety risk to the public; in light of this we are prioritising replacement of some other assets first, and ramping up this work as the period proceeds.

Further discussion of these expenditure drivers is set out below.

Subtransmission

The main determinant of subtransmission cable life is how well the integrity of the cable sheath can be maintained. As a result, key drivers of renewals are cable type and age. Table 5.11 sets out known type issues by cable type. All types of cable deteriorate with age, and older joints are more likely to fail.

The instantaneous effects of a subtransmission cable failure are typically mitigated by the redundancy provided in the network design. However, repairs to subtransmission cable failures can be lengthy operations, creating significant reliability risk for the duration of the repair. There is also some environmental risk associated with leaking oil from the oil-filled types.

As the cable sheath deteriorates, decisions as to whether to maintain the cable in service or replace it are also affected by whether we are able to efficiently respond to faults in the cable, joints or terminations. It will become increasingly difficult to retain specialist expertise to carry out jointing and repairs of some cable types. We plan to improve our contingency preparedness in this area.

Table 5.11: Underground Cables Known Type Issues – Subtransmission

TYPE	ISSUES
Gas-filled pressurised cable	Bronze tape corrosion Gas leaks (also difficult to locate leaks)
Oil-filled pressurised cable	Minor oil leaks (environmental issue[64])
PILC	Drying out below joints accelerates age-related failure.

We have observed leaks in gas cables at cable joints, caused by cable movement and corrosion of the bronze tapes which hold the lead sheath in place. The root cause of this issue is moisture entering the cable following deterioration of the cable’s rubber sheath. Analysis shows a high failure rate of gas-filled cables over the past 20 years, with incidents occurring almost annually. Gas leaks can be difficult and costly to locate, and we plan to replace all remaining gas-filled cable over the period to 2023.

64 None of the ingredients of the cable insulating oil product are classified as hazardous. The substance is a mobile liquid, which is insoluble in water and is readily biodegradable. As such any environmental impact is small.

In the Dunedin network our older PILC cable 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 affected cable within several years.

The condition of the sheath of our oil-filled cable is generally acceptable though some minor leaks are of concern, as they pose an environmental risk. We have had an issue with an intermittent fault on the North City 2 cable since 2009 which we have been unable locate despite significant investigation work. We have scheduled replacement of our oil-filled cable for later in the planning period; we will review these replacements on the basis of condition, performance and risk closer to the time.

The planned replacements are supported by performance data on our subtransmission cable. Figures 5.17 and 5.18 show the frequency and duration of equipment outages of subtransmission cable equipment since 2012. Most issues relate to our aged PILC and gas-filled pressurised cable which are scheduled for near term replacement. Outage duration is important when considering cable assets, as it can take an extended time to repair these assets and return them to service, particularly in the case of oil-filled cable.

Figure 5.17: Subtransmission cable performance – frequency of faults

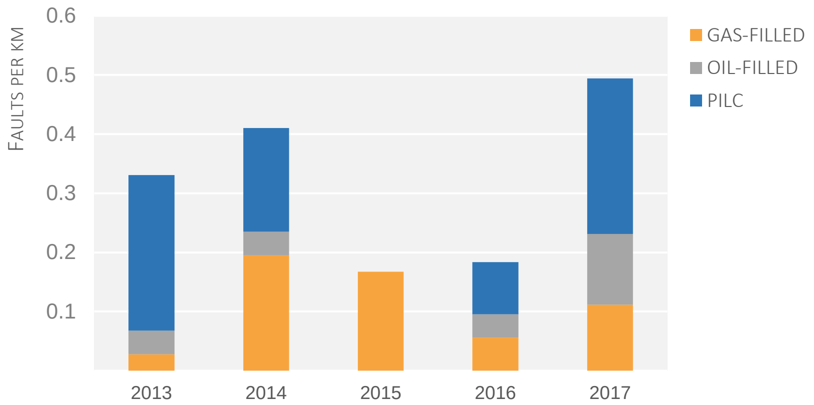
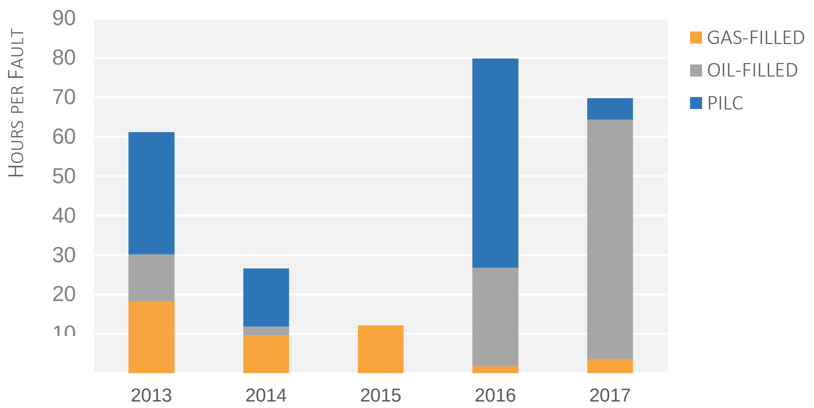


Figure 5.18: Subtransmission cables performance – duration of faults



The current network configuration delivers very good performance during typical asset failure modes, but it can be vulnerable to high impact, low probability events such as earthquakes or tsunami as it does not allow for any significant load transfer between GXPs. As part of our risk-based approach we are investigating options to improve the resilience of our Dunedin 33 kV network to such events, as discussed in Box 5.8.

Distribution

Our distribution cables sub-fleet is relatively young, and we believe it is in generally good health, as illustrated in the asset health chart, above. We have had some minor issues affecting performance, as described below.

Table 5.12: Underground Cables Known Type Issues – Distribution

TYPE	ISSUES
PILC	Cast iron pothead terminations are prone to age-related failure, presenting a safety issue
	Non-waxed PILC termination leaks
	Lead sheath condition (crystallisation) – earthing issue
XLPE – non -TR (1^{st} gen)	Water ingress resulting in higher failure rate compared to XLPE-TR

In general PILC cable does not cope well with being moved. We are seeing some lead crystallisation on low voltage distribution cable sheath which can result in a water ingress issue if the cable is moved. We will replace sections of this cable as needed. We prefer to do this work when we are already undertaking other work on or near it to minimise movement.

We have been actively replacing cast iron potheads terminations since 2014. These present a safety issue (explosive hazard) when re-energising which we currently manage by isolating them from the public. We will replace all of the remaining cast iron pothead terminations during the planning period.

In the late 1990s we installed a small batch of PILC cable that used a low viscosity oil within the paper layers rather than grease. Most of the terminations used at that time were not rated for the pressures the low viscosity oil created as the cable heated. Some of the terminations that have wept have been replaced. We are monitoring the termination leaks, and will initiate replacement when warranted.

We have both first and second generation XLPE distribution cable in service. Water ingress issues with the first generation type is expected to require replacement of some cable sections during the planning period.

LV Cable

We do not explicitly monitor the condition of our LV cable, as reactive replacement is the most cost effective approach unless the cable is being upgraded to provide additional capacity. As the asset is relatively young and is not operated under stress we believe that it is in reasonably good condition. We expect to replace only a small amount of LV cable on the basis of condition during the planning period.

The majority of LV cable failures are attributable to damage from third party construction and poor initial installation of the terminations, allowing water ingress. We are monitoring the condition of our cast iron tee joints used on PILC cable; these are located below ground and are expected to eventually allow water ingress resulting in cable faults.

5.6.3. Maintenance Approach

Cables are generally maintenance free, but we do take a proactive approach to managing them. This involves regular inspections and diagnostic testing, and repairs where needed to minimise deterioration. Gas and oil-filled cables require additional maintenance due to their pressurisation systems. When it becomes uneconomic to maintain a cable in-service as a result of age-based or other deterioration we proactively replace the cable. Our maintenance and inspection regime for our cable assets is described below.

Preventive Maintenance

Our primary maintenance tool to support this approach is inspection and condition monitoring. As we cannot visually inspect the condition of the cable itself, this is supplemented by diagnostic testing to identify any issues in a timely manner.

Table 5.13: Underground Cables Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
Sub-transmission cable	Ground-based visual inspections of terminations	Identify asset deterioration or damage that could lead to future failure	Annually
	Oil and gas-filled pressure tests	Provide early detection of possible leaks	Two-weekly
	Alarm tests	Confirm condition of alarms	Six monthly
	Outer sheath electrical integrity testing	Obtain reliable evaluation of condition, identify deterioration or damage	Annually
Distribution / LV cable	Inspect cable risers	Inspect condition of cable risers	Five yearly (during pole inspections)

Corrective and Reactive Maintenance

We monitor subtransmission and high voltage cable performance via SCADA, while low voltage faults are often identified when loss of supply occurs. Fault response may be required in the event of a cable asset failure, to locate the issue or make the area safe.

Corrective maintenance of cable assets is planned work to remediate defects identified either during preventive maintenance or first response to a fault. Defects may be addressed by replacing cable sections, joints or terminations (Capex), or by sheath repairs. Locating and repairing cable faults can be substantially more expensive and take considerably longer than repairing faults on overhead lines. We undertake post-fault root cause analysis for all subtransmission failures, which enables us to identify if end-of life failures are occurring.

Spares Management

We retain spares to manage risk associated with most of our subtransmission fleet. We have experienced some problems procuring replacement spares for some of the older cable accessories and terminations on the subtransmission PILC cables. This issue will be resolved by replacing aged cable in coming years. We have sufficient spares to maintain our oil-filled cable until replacement.

5.6.4. Renewals and Refurbishment

Table 5.14 provides a summary of our renewal approach for underground cables.

Table 5.14: Summary of Underground Cables Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition and criticality
Medium term forecast (renewal volume)	Asset health
Cost estimation	Tailored (subtransmission), volumetric

Capex Investment Drivers

The key drivers for cable replacement are asset age and type issues (asset health).

Our focus during the planning period is on replacing gas-filled, oil-filled and aged PILC subtransmission cable which has suffered degradation of the cable sheath due to both age and type issues. This will mitigate performance and safety risks.

For distribution cable, we will replace sections of PILC and first generation XLPE as warranted by condition. Full replacement is undertaken only when it is uneconomic and impractical to maintain the cable in service using repairs and sectional replacements. We have a programme of work to actively replace cast iron pothead terminations to mitigate the associated safety risk.

When replacing subtransmission and distribution cables our technology of choice is single-core XLPE. This is the most economically efficient choice today, and the single core type facilitates the effective application of water blocking. As most of Dunedin City's subtransmission cable is coming due for replacement, we are considering alternative configurations for the Dunedin network that will enable us to better manage risk.

Box 5.8: 33 kV subtransmission cable network reconfiguration

In this AMP we have assumed that replacement of our 33 kV cables in Dunedin will be on a 'like-for-like' basis. However, while the current network configuration delivers very good performance during typical asset failure modes, it can be vulnerable to high impact, low probability (HILP) events such as earthquakes or tsunami. It does not allow for any significant load transfer between GXPs. The Dunedin Hospital rebuild, scheduled to occur during the AMP planning period, will also affect renewal plans, particularly around the North City substation.

As part of our risk-based approach we are investigating options to improve the resilience of our Dunedin 33 kV network to HILP events. Reconfiguring the 33 kV subtransmission network to create more interconnection would provide flexibility to switch supply between GXPs, reducing site and circuit route dependency. This would provide significant resilience benefits relative to the existing network configuration which does not allow for any significant load transfer between grid exit points. Strategic staging of the new interconnection links would reduce dependency on the aging 33 kV cables and may therefore enable us to defer some of our 'like-for-like' replacement.

The cost of a reconfigured network is likely to be slightly higher than a straight replacement: while slightly less cable investment would be needed, additional investment in 33 kV switchyards at zone substations would be required.

Forecasting Approach

Our forecasts for both subtransmission and distribution cable focus on improving performance of the subtransmission fleet in order to achieve performance consistent with acceptable industry practice.

Subtransmission cable replacements are forecast on an individual project basis, with costs estimated based on project specific factors. Forecast expenditure on cast iron pothead replacements uses a volumetric method, with unit rates based on recent historical costs. Costs are higher in the CBD than in suburban areas.

5.7. DISTRIBUTION SWITCHGEAR

This section describes our Distribution Switchgear fleet and summarises how we manage these assets.

5.7.1. Overview of Fleet

Switchgear is the collective term for equipment used to provide network isolation, protection and switching facilities. The distribution switchgear fleet comprises a large number of diverse asset types. It excludes switchgear contained in zone substations.

Our fleet plan for distribution switchgear is broken down into the following sub-classes:

- Reclosers and sectionalisers
- Ground-mounted switchgear
- Pole-mounted switchgear
- Low Voltage enclosures.

We use reclosers and sectionalisers when distribution switchgear needs to fulfil a protection function such as automatic isolation and restoration of the network following temporary faults. Circuit breakers, in the context of this fleet, are associated with distribution substations.[65] Reclosers provide mid-feeder isolation to reduce the impact of a network fault. They are pole mounted devices which detect downstream faults and isolate the faulted part of the circuit before the upstream supply circuit breaker reacts, reducing the area affected by a fault.[66] A recloser at the boundary between an urban area and outer rural sections protects the higher density urban portions of feeders from the higher fault rate on the rural sections. Sectionalisers are similar to reclosers but rather than opening to clear the fault, they open after the upstream circuit breaker or recloser has reacted to the fault. Sectionalisers are also generally pole mounted.

Ground mounted switchgear incorporates switching equipment that provides distribution network isolation, protection and switching facilities. It includes ring-main units (RMUs), switches, HV fuses and HV link pillars and associated enclosures. Our fleet comprises a range of makes and models with various insulating media.

Historically we used oil-filled switchgear, but it is not used in new installations. It is no longer available for purchase, and also requires intensive maintenance (relative to modern assets), is not designed to

65 Zone substation circuit breakers are discussed in Section 5.9.

66 Reclosers attempt to restore supply by automatically 'reclosing' on the faulted section if the fault has self-cleared. This enables clearing of transient faults caused by tree branches, vermin or windblown debris and avoids lengthy outages.

meet modern operational safety requirements, and most types are no longer supported by manufacturers. We now predominantly install SF_6 (sulphur hexafluoride) insulated switchgear and solid dielectric insulated vacuum switchgear utilising arc containment designs.

Pole mounted switchgear includes switches, fuses, and links. Pole mounted fuses are simple devices that provide protection and isolation ability, primarily isolating and protecting distribution transformers. Pole mounted switchgear comes in a wide variety of configurations and insulating mediums (SF_6 and air). For switches, we most commonly we utilise air break switches (ABSs) which use air as the dielectric and can be operated using a handle mounted at ground level. ABSs are used for sectionalising feeders to find and isolate faults and as open points between feeders. A standard ABS has limited load break capability, so we have added this capability to some units to improve operability. We use very few SF_6 switches.

LV enclosures are typically used to supply domestic/small installations. LV pillars are above-ground enclosures while LV box refers to the below-ground variant. Third party damage is a significant cause of issues for these assets as a result of vehicle damage and vandalism.

Box 5.9: Fleet Objectives

We have established the following objectives for the Distribution Switchgear asset fleet:

- No injuries to the public or personnel due to maloperation of switchgear
- Improve asset condition information to support renewal planning
- Assess arc flash risk for switchgear to support prioritisation of renewals (together with condition)
- Compliance with environmental regulations related to the containment of oil and SF_6

Key strategies for achieving these objectives are:

- Reduce risk by focusing renewals programme based on criticality.

Population

Table 5.15 provides a breakdown of our distribution switchgear by type. There is significant diversity in the fleet, with a large number of manufacturers represented. Diversity increases the cost and complexity of maintenance and raises safety risks as field personnel are less familiar with each model. We are standardising our ground mounted switches to the extent this is practicable. This issue is less relevant to fuses which are all relatively similar in design and function.

Our RMU sub-fleet is dominated by oil-filled ABB units, which comprise about 75% of RMUs. Oil-filled units, in aggregate, comprise 80% of all RMUs.

We have both above and below ground variants of LV service and link enclosures. Most new enclosures are the below ground variants (LV boxes).

Table 5.15: Distribution Switchgear Population (as at 1 June 2018)

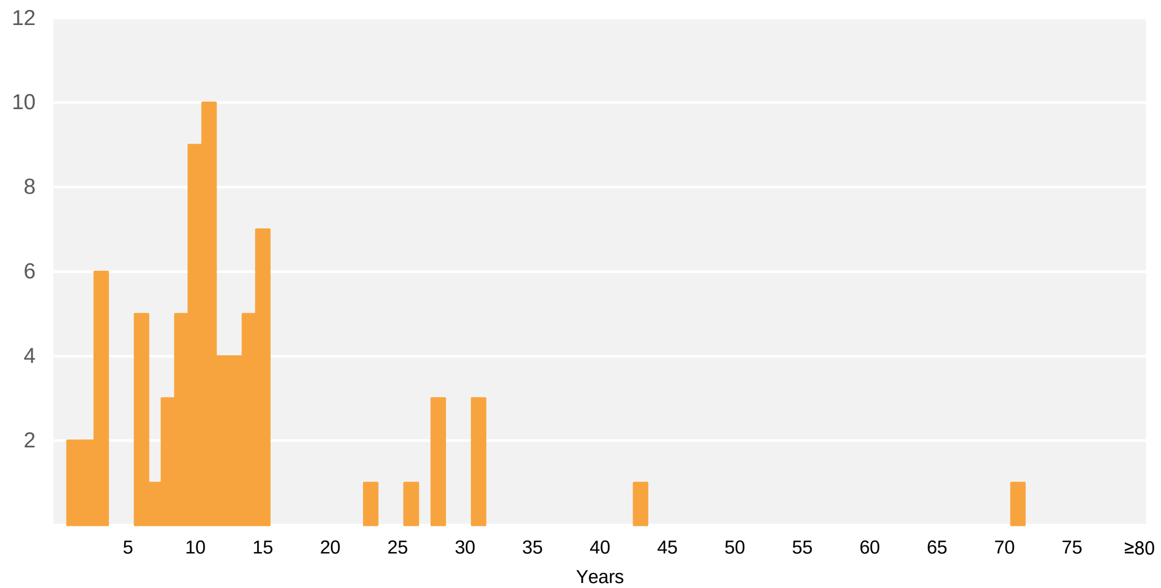
TYPE	SUB-TYPE	POPULATION
Reclosers and sectionalisers		67
Ground-mounted switchgear	RMUs and switches	1,361
Pole-mounted switchgear	Fuses	5,598
	Switches	1,355
LV Link Enclosures		2,679
LV Service Enclosures		17,881

Age Profiles

Most of our switchgear assets have a life expectancy of more than 40 years. The charts set out below show the age profiles of each sub-fleet.

Our reclosers and sectionalisers sub-fleet is young relative to the 45 year expected life of these assets. Most of the existing reclosers are the vacuum type, though we still have a small number of oil insulated vacuum interrupter type reclosers. New reclosers are the vacuum solid insulated type.

Figure 5.19: Distribution Switchgear Age Profile – Reclosers and Sectionalisers (as at 1 June 2018)



Our ground mounted switchgear assets are also relatively young (average age 24 years) though many units have already exceeded their 40 year expected life. Over the past six years we have predominantly installed SF_6-insulated and solid dielectric insulated vacuum switchgear utilising arc containment designs. SF_6 equipment, in particular, is cost effective, and the environmental considerations associated with it are well understood. However, we are aware that environmental concerns may limit future use.

Figure 5.20: Distribution Switchgear Age Profile – Ground Mounted (as at 1 June 2018)

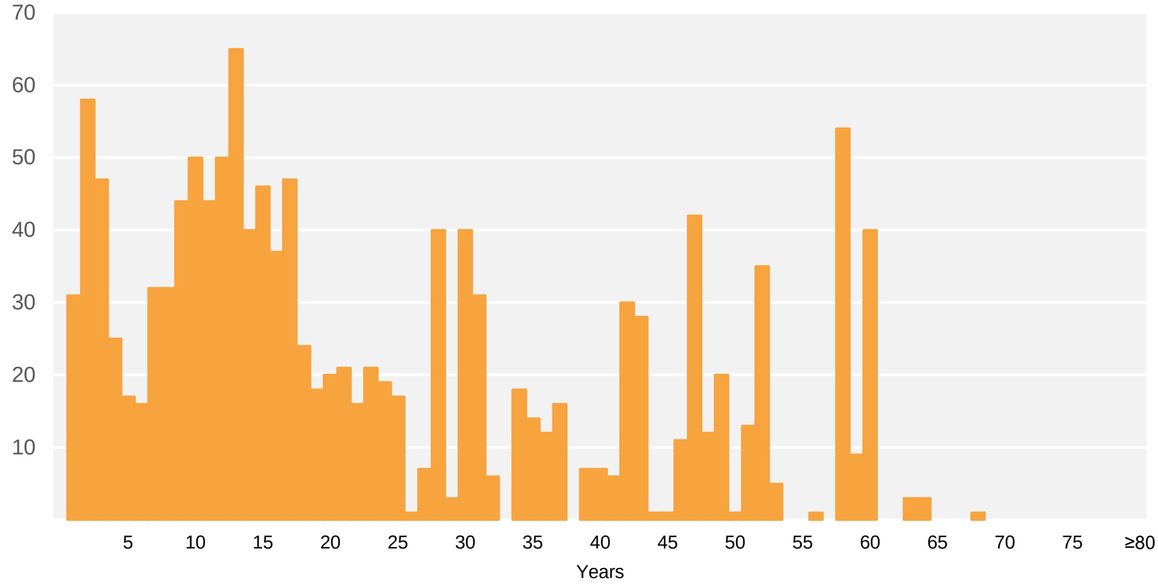
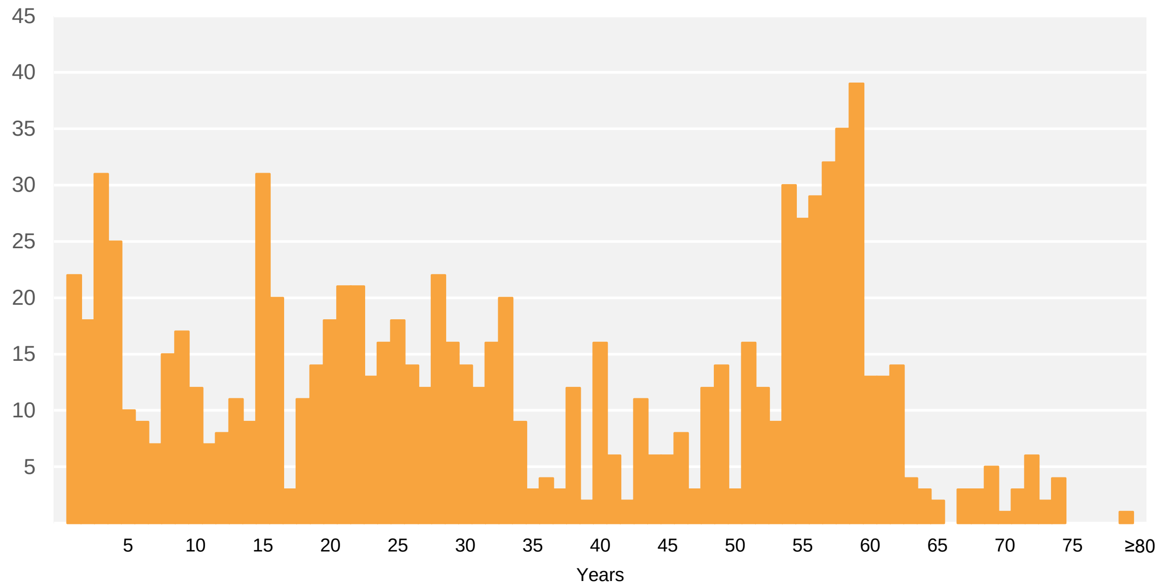


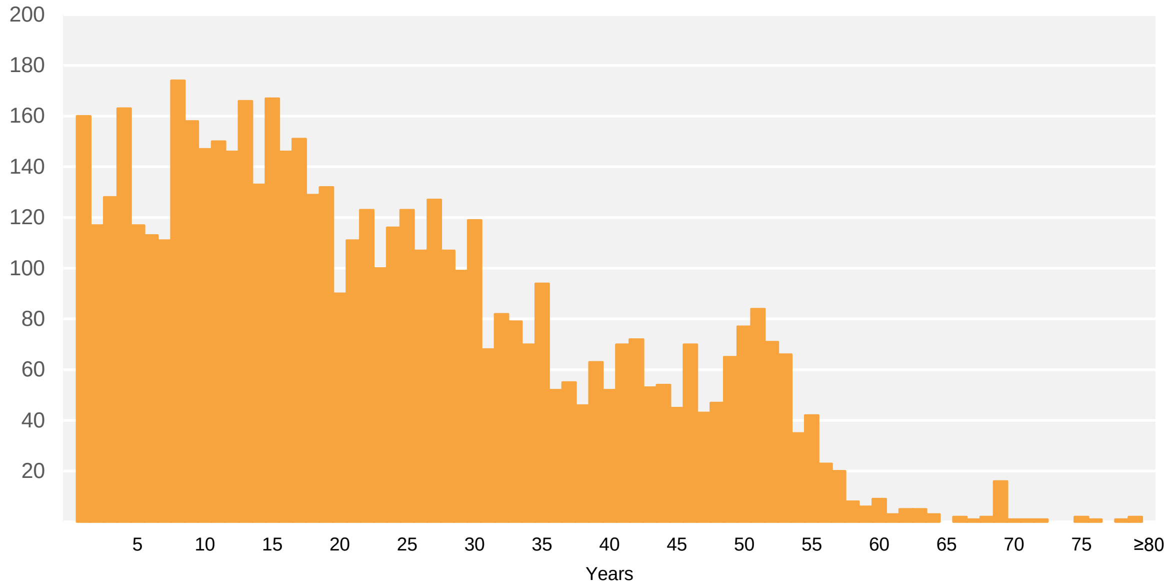
Figure 5.21 shows that a large number of our pole mounted switches have already exceeded their 40-45 year expected life. We have also identified some condition issues with these assets, as described later in this section.

Figure 5.21: Distribution Switchgear Age Profile – Pole Mounted Switches (as at 1 June 2018)



Many fuses are replaced as part of pole replacement work, otherwise we replace fuses reactively as the consequences of failure are minor and it is only cost effective to replace them proactively where defects are identified during visual inspections. Fuses have an expected life of 35 years.

Figure 5.22: Distribution Switchgear Age Profile – Pole Mounted Fuses (as at 1 June 2018)



5.7.2. Condition, Performance and Risk

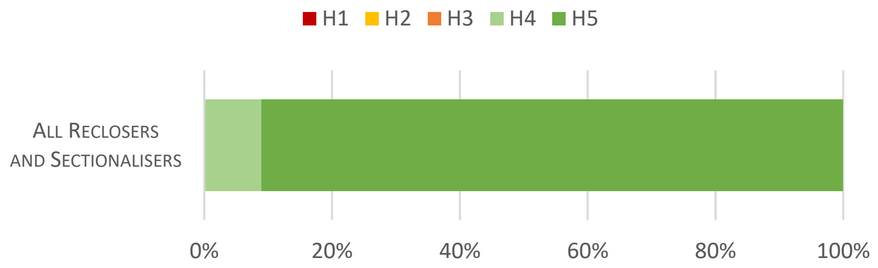
Key degradation modes for our distribution switchgear assets are deterioration of insulation, corrosion of enclosures and wear on mechanical components (in line with the number of individual operations performed). Older switchgear designs generally have fewer safety features, are less reliable and require more maintenance than modern assets. Older assets may also become obsolete through a loss of manufacturer support.

We collect only limited condition data for our distribution switchgear assets. (In the case of RMUs the data collected is comprehensive, but requires more work to enable it to be utilised for reporting condition and decision making). However as the main degradation modes for switchgear are age-related, age provides a useful proxy for condition where insufficient other information is available. Where specific 'type issues' have been identified for an asset, these are also included in the assessment of asset health.

Reclosers and Sectionalisers

We have not historically collected condition data for these assets. Overall we believe they are in good health other than some minor communications issues, because they are young, modern asset types and have few recorded defects and low operation counts. We estimate renewal needs using an age-based asset health model (Figure 5.23), and do not expect that any replacements will be needed during the planning period.

Figure 5.23: Distribution Switchgear Asset Health – Reclosers and Sectionalisers (as at 31 March 2018)

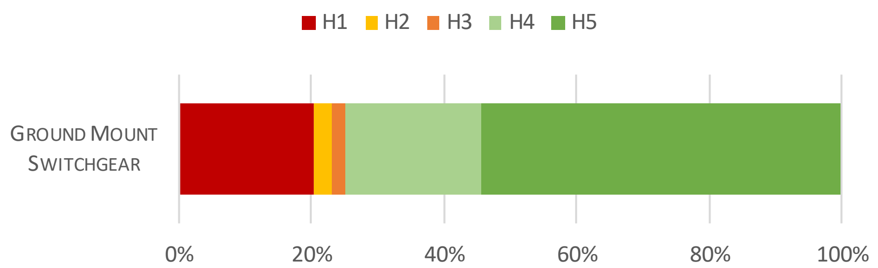


Ground-mounted switchgear

We have not historically collected condition data for our ground mounted switchgear. Recognising the need to better understand their condition, we altered our strategy and commenced annual inspections of our RMUs in 2017. While we had some issues with mapping condition data to individual assets, the results provide a reasonable indication of overall sub-fleet collection and indicated that the assets are in reasonable condition. Few failures of these assets have been recorded. Future inspections will provide data to support short-term renewal and maintenance scheduling.

As the mapping issue noted above prevents us using actual condition data in this model, we have developed an age and type issue-based asset health model to estimate renewal needs. This is shown in Figure 5.24. We have taken the conservative approach of reducing the expected lives of all switchgear with known type issues, which has resulted in the large H1 category. Actual risk associated with type-issue switchgear may be lower than shown in the chart; we will firm up our view on this following the next inspection, for example, we may find that some assets included the H1 category due to a type issue have considerable life remaining.

Figure 5.24: Distribution Switchgear Asset Health – Ground Mounted Switchgear (as at 31 March 2018)



Box 5.10: Investment Plans

To manage risk associated with our ground mounted distribution switchgear assets we are:

- replacing 120 ground mounted units over the next three years
- prioritising replacements based on safety and reliability risks
- aiming to replace all high risk and all H1-classified switchgear by 2025.

Our 10 year plan includes $18 m of renewals, leading to less than 1% of units classified as end of life (H1) by 2028.

As described in Chapter 8, our forecast expenditure provides for replacement of all of our ground mounted switchgear with known type issues within the earlier part of the planning period. We also plan to replace all of our Henley in-ground LV enclosures over the planning period.

In 2014, we began a programme to remove aged, high-risk oil-filled RMUs, and this has resulted in an improvement in the health of the sub-fleet. The safety of older oil-filled switchgear continues to be the key risk in relation to our distribution switchgear. We also have some issues with surface tracking due to gaps in maintenance.

Oil-filled switchgear can fail with rapid burning (deflagration) as highlighted in a recent incident in Australia that occurred during switchgear maintenance. The consequences of oil-filled switchgear failure are much greater than for modern equivalent assets. We have imposed restrictions on operation of some of our oil-filled RMUs to reduce safety risk until such time as they can be replaced.

A small number of RMUs manufactured by Statter, Reyrolle, GEC and Andelect remain in-service following our earlier replacement programme. These units no longer have manufacturer support, require more maintenance than modern units, and have operational restrictions imposed on them. Replacement of these units will be our highest priority.

The majority of our RMUs are the ABB 'Small Dimension' (ABB-SD) type. Though not as old as the other types, we are seeing signs of mechanical failure with these units, attributable to poor material specification. We have adopted the use of remote switching devices with these assets to mitigate operational hazards, and will be monitoring their condition to support future replacement planning.

Manufacturer expertise and spares have become available for our Long and Crawford RMUs. We expect to achieve a significant life extension for these RMUs, making them our lowest replacement priority of the oil-filled units.

The very low number of 'orphaned' Magnefix Ltd. switches on the network leads to operator competency challenges and we plan to replace all these HV fuse / link pillars during the planning period.

Table 5.16: Distribution Switchgear Type Issues – Ground Mounted

TYPE	ISSUES
Statter, Reyrolle, GEC, Andelect and ABB-SD RMUs	These oil-filled RMUs suffer from a number of issues resulting in safety and performance risks due to design and installations issues
Magnefix Ltd. HV fuse /link pillars	These assets require specialist manual operators. Due to the small orphan population it is difficult to keep operator competency current. Without this they do not operate as well as they should.

Note that manufacturer and model data for our ground mounted switchgear is incomplete, and in order to forecast renewal volumes we have had to make inferences with respect to the number of each make and model in service. We are working to address this data gap using information obtained during our recent RMU condition assessment.

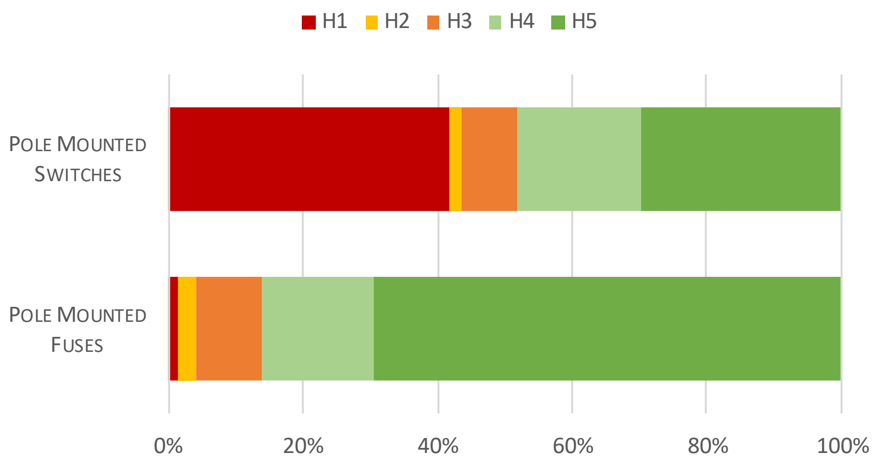
Pole-mounted switchgear

We visually inspect our switches and fuses on a regular basis, but do not undertake detailed assessments of condition. Switches in suspect condition are removed from poles and replaced with a new or reconditioned switch from the spares pool. The condition of the removed switch is then assessed and if reusable, any required remediation work is carried out before it enters the pool of spares.

Fuses may be replaced reactively, in response to visual inspection, or as part of a pole replacement. At times, only the fuse cartridges will need to be replaced. We are aware of some corrosion issues with both switches and fuses, particularly in coastal areas.

No type issues have been identified for pole mounted switches, so a straight age-based model is used to estimate asset health. For fuses, we use a survival curve to estimate asset health. Asset health is shown in Figure 5.25.

Figure 5.25: Distribution Switchgear Asset Health – Pole Mounted (as at 31 March 2018)



Box 5.11: Investment Plans

To manage risk associated with our pole mounted distribution switchgear assets we are:

– replacing ~200 fuses and ~300 pole mount switches over the next three years in line with asset health

– prioritising replacement of "Do Not Operate" pole mounted switches, with all those classified as H1 to be removed by RY23.

Our 10 year plan includes $7 m of renewals, leading to less than 1% of poor condition (H1) pole mounted switches and fuses on the network by the end of the period.

We have had a number of performance issues with our older pole-mounted switches including the contacts welding together under fault conditions and jamming of the operating handles. Issues with aged assets often relate to asset design or historical maintenance practice, for example, operating handles jam as a result of not being operated and maintained regularly, preventing the switch from operating. We expect that we will need to replace a significant number of our ABSs during the planning period.

We are also phasing out one type of fuse, due to failure of the stand-off insulators on the fuse mounts. The manufacturer concluded that failures were due to corrosion of the aluminium that was used as an insert in the product over the period from the late 1960s to the 1990s. These fuses are subject to operational restrictions. We expect to replace additional fuses based on condition.

Table 5.17: Distribution Switchgear Type Issues – Pole Mounted

TYPE	ISSUES
Fuses	HRC fuses in Dunedin network have faulty insulators on FD-A fuse mounts such that the mounts may break when operated

LV Enclosures

We have not historically inspected our LV Enclosures so we do not have data regarding the health – or in many cases the age – of these assets. However, LV pillars are robust assets, with the major failure modes being random and unpredictable – vehicle collisions and vandalism. These pillars do present some public safety risk due to their accessibility to the public and the risk of electrocution should the asset be damaged (such as by vehicle collision). We replace these, as warranted, with modern in-ground LV link boxes that eliminate these operational risks.

The main type issues driving renewal of LV enclosures are set out in Table 5.18.

Table 5.18: Underground Cables Type Issues – LV Enclosures

TYPE	ISSUES
Link Enclosures	Underground enclosures are degrading due to water ingress. These also face safety issues including high arc flash potential, and exposed terminals (Henley type)
	Porcelain links – arc flash issues arising from open exposed links that are not arc flash rated (J-type)
Service Enclosures	Some older steel type service pillars are not earthed – public safety issue
	Plastic enclosures with lids affixed with metal screws present a safety issue, as lids can be knocked off exposing live parts (Central network)
	Water ingress into service boxes - water seals failing prematurely

Within our population of in-ground link boxes we have a small number of Henley in-ground LV enclosures, most of which are more than 45 years of age. These enclosures have water ingress issues, and exposed live terminals during operation. We recently trialled alternative modern design link boxes before settling on the Quadlink as our preferred type. In the meantime, we manage the risk associated with these assets using skills training and procedural requirements.

We have identified several safety risks associated with our service enclosures. We are repairing un-earthed service pillars as these are identified, and actively seeking to identify and replace metal screws on plastic type enclosures. Failure of water seals is being managed through maintenance processes.

5.7.3. Maintenance Approach

In establishing our maintenance requirements, we balance manufacturer recommendations, our own experience with the assets, and risks associated with them. Recently introduced Health and Safety legislation also has an impact, restricting the amount of work that can be carried out energised, for example, live tank oil sampling.

Preventive Maintenance

Table 5.19 sets out the key preventive maintenance activities for our distribution switchgear assets.

Table 5.19: Distribution Switchgear Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
Reclosers and sectionalisers	Circuit breaker thermal imaging	To identify hotspots on circuit breakers which may indicate damage, in order to prevent functional failure	Annually
	Trip Timing	Ensure circuit breaker works as designed	Four yearly with protection tests (new regime)
	Recloser maintenance	Identify visually apparent defects, perform operational checks, clean, minor repairs	Four yearly (new regime)
Ground mounted switchgear	Oil filled ground mount switch – Routine inspection	Check switch is free from obvious heat damage, vegetation is in check, site is secure, surface has a reasonable level of protective paint and equipment mounting/ foundation is fit for purpose. Partial discharge testing, re-make cable termination if they fail partial discharge tests.	Annually
	Oil filled ground mount switch – Full invasive maintenance	Thorough servicing of the unit to ensure it is maintained to an acceptable level. Includes replacing non-conforming Perspex covers on the front of T4GF3 RMUs, check fuse carriers / fuse racks, replace fuse contacts if dislodged/cracked, full oil change / silting, flushing tank with clean oil, testing oil dielectric strength (prior & after maintenance), moisture content, and oil acidity	Six yearly
Pole mounted switchgear	33 kV air break switches visual inspections	Identify visually apparent defects, carry out diagnostic testing, perform operational checks, and carry out minor repairs	Five yearly
	11/6.6 kV air break switches visual inspection	Identify visually apparent defects, perform operational checks, and carry out minor repairs	Five yearly
LV enclosures	Inspection and minor repairs	Identify visually apparent defects and carry out minor repairs	Five yearly standard (more if high risk of third party damage)
	Distribution earth testing	Verify integrity of earth grid	Five yearly

Corrective and Reactive Maintenance

Corrective maintenance is planned as needed. Defects may be identified during preventive maintenance or scheduled following first response to a fault.

Repairs include levelling of switchgear, oil changing/top-up, addressing damage to panels, and replacing water seals on service boxes. For pole mounted switches and fuses we only undertake very simple repairs in-situ, for example, replacement of fuse cartridges. In most cases the unit is removed and replaced, with the old unit repaired and returned to the pool of spares, if possible.

Spares Management

We operate a rotable spares pool for our ground and pole mounted switches. When units are removed from service, we assess whether they should be reconditioned or scrapped. Refurbished units are returned to the pool. We retain strategic spares for items with long lead times or which are not part of standard inventory (orphan spares).

5.7.4. Renewals and Refurbishment

Table 5.20 provides a summary of our renewal approach for our distribution switchgear assets.

Table 5.20: Summary of Distribution Switchgear Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition, criticality (safety) and type issues
Medium term forecast (renewal volume)	Asset health, historical trend (for reactive renewals)
Cost estimation	Volumetric

Capex Investment Drivers

The main drivers of Capex in distribution switchgear assets are age/condition, performance, and safety type issues.

We plan to replace certain models of oil-filled RMUs, fuses and reclosers on the basis of safety and condition, as the risks associated with these assets cannot be satisfactorily managed operationally. In relation to our link and service enclosures, we have some active replacement programmes in place to manage safety and performance type issues.

Replacement of some pole mounted units may be carried out as part of a pole replacement, though often the used units can be refurbished and returned to the spares pool.

Forecasting Approach

All forecasting for distribution switchgear assets is volumetric. Unit rates are based on the historic costs.

5.8. DISTRIBUTION TRANSFORMERS

This section describes our Distribution Transformers fleet and summarises our management plan for the assets.

5.8.1. Overview of Fleet

Our fleet plan for distribution transformers is broken down into the following sub-fleets:

- Ground-mounted distribution transformers
- Pole-mounted distribution transformers
- Voltage regulators and auto-transformers
- Mobile distribution substations.

A distribution transformer is a device used in electrical circuits to transform the voltage of electricity to a suitable level for customer connections. Transformers come in a variety of sizes, single or three phase and can be either ground or pole mounted. We have a large number of legacy assets of varied types and designs between our two networks.

Voltage regulators are designed to automatically maintain a set voltage level. The length of some of our 11 kV distribution lines necessitates the installation of voltage regulators partway along the feeders to maintain the correct voltage at the end of the feeder (to compensate for undersized and/or long rural lines where growth has created voltage issues). This enables reconductoring to be deferred until warranted. Voltage regulators are controlled primarily by digital controllers, with a few older controllers in service. We use 0.5 to 5 MVA auto-transformers in parts of the network to enable interconnection of 6.6 to 11 kV circuits. We have other higher rated auto-transformers elsewhere in the network.

Box 5.12: Fleet Objectives

We have established the following objectives for the Distribution Transformers asset fleet:

- Reduce public safety risks arising from unauthorised access to electrical enclosures, contact with live metal, step and touch potential, leaking oil and excessive noise
- Where economic, transition from age-based to condition-based forecasting and replacement
- Achieve asset lifecycle efficiency by seeking out opportunities to minimise replacement costs and associated customer outage impacts.

We have developed the following strategies to support these objectives:

- Replace pole mounted transformers reactively when 100 kVA or less
- Replace pole mounted transformers based on condition when larger than 100 kVA
- Replace transformers during pole replacements when remaining life is less than 15 years
- Replace ground mounted transformers based on condition
- Reduce earthquake exposure and operational safety risks by converting larger pole mounted transformers to ground mounted units as they become due for renewal
- Develop an inspection and condition assessment methodology for pole mounted transformers to identify defects for repair and capture information for asset health reporting
- Refine the transformer condition assessment collection and process to align with our asset health classification categories.

We have three mobile distribution substations which operate at 11 and 6.6 kV. They are used to bypass permanent distribution substations to enable both planned and fault work.

We have a variety of types of ground-mounted distribution transformers (example photo on the right). Pole mounted units may be sited on either single, pole and a half or double pole structures, depending on what is needed to support the specific transformer.

Pole mounted transformers often have exposed terminals so must be sited at a safe clearance above ground.

Population

We have more than 7,000 distribution transformers on our networks. Our ground mounted units range from smaller than 100 kVA to larger than 1,000 kVA, while 90% of our pole mounted units are smaller than 100 kVA. Our mobile distribution transformers are 300 and 500 kVA.

Table 5.21: Distribution Transformers Population (as at 1 June 2018)

TYPE	POPULATION
Ground-mounted distribution transformers	3,022
Pole-mounted distribution transformers	3,994
Voltage regulators (number of sites)	13
Auto transformers	9
Mobile distribution substations	3
Mobile generators	3

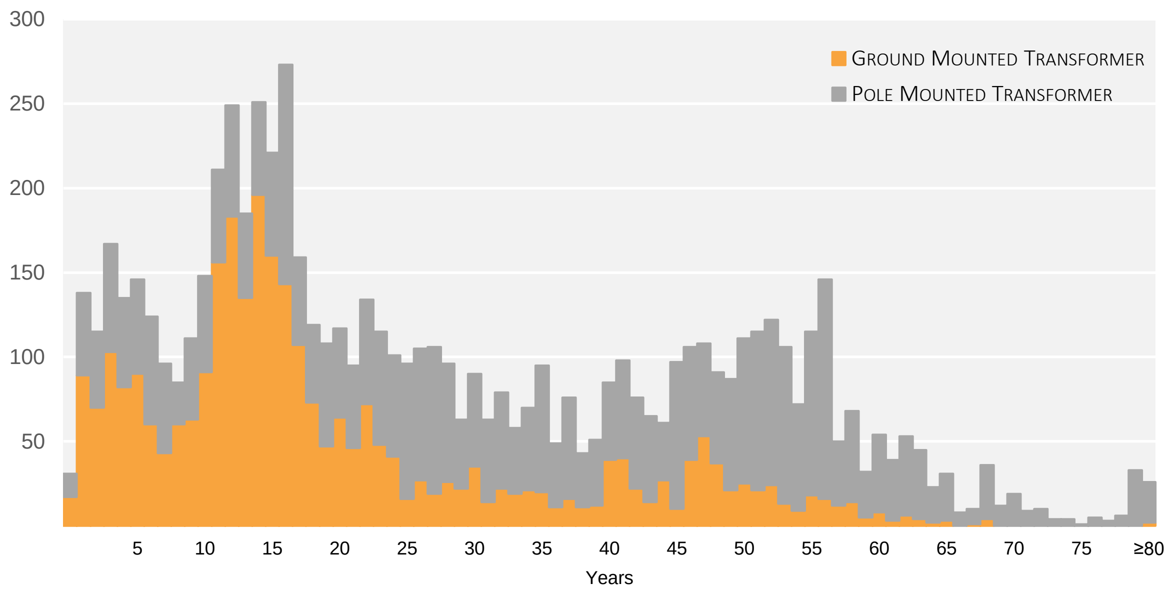
Age Profiles

Our ground mounted distribution transformer population is relatively young, with the majority of the population less than 25 years old, relative to an expected life of 70 years.

Our pole mounted population is older, with about 400 pole mounted units already exceeding their 60 year expected life, and a considerable number nearing that age.

Nearly all of our voltage regulators are under 20 years of age. They have an expected life of 45 years. In contrast, our auto transformers are 50-60 years of age and showing signs of end of life. Our three mobile distribution substations are also nearing end-of-life.

Figure 5.26: Distribution Transformers Age Profile (as at 1 June 2018)



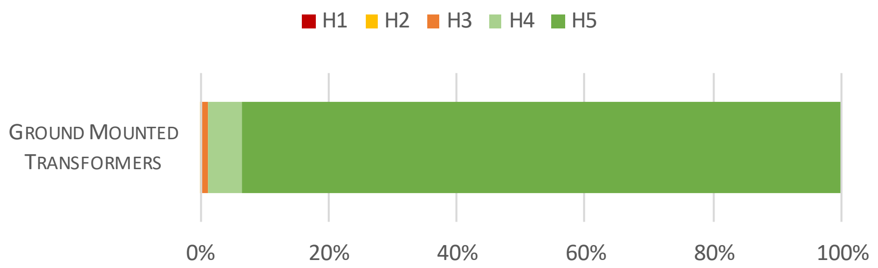
5.8.2. Condition, Performance and Risk

We determine asset health for our distribution transformers based on age and, in some cases, condition. Asset health is used for renewal forecasting. Age-based models are appropriate because the common failures modes for distribution transformers – with the exception of third party damage – are largely age related, for example, external corrosion, leaking radiators, oil leaks due to surface corrosion of the tank, gasket failure or mechanical failure, and moisture and other contaminates in the oil.

Asset Health

Figure 5.27 shows the asset health of our ground mounted distribution transformers.

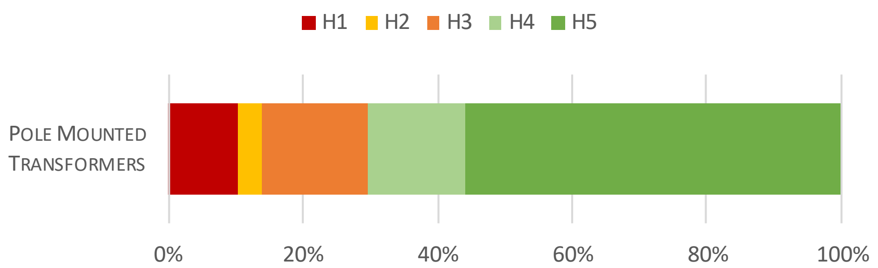
Figure 5.27: Distribution Transformers Asset Health – Ground Mounted (as at 31 March 2018)



Corrosion of enclosures and radiators are the most common defects on these assets. This sub-fleet is relatively young and we believe the assets are generally in good health, i.e. asset condition is fairly represented by age. As such, our asset health model is age-based. Condition information is primarily used for prioritising remediation of defects.

Figure 5.28 shows asset health for our pole mounted distribution transformers. This is currently based on age, though condition data will be incorporated when this becomes available. Our condition monitoring programme, focussing on larger and older pole mounted units, is programmed to start in 2020.[67]

Figure 5.28: Distribution Transformers Asset Health – Pole Mounted (as at 31 March 2018)



67 It is not cost effective to monitor the condition of smaller pole mounted units which are generally run to failure.

Box 5.13: Investment Plans

To manage the risk associated with our distribution transformers we are:

- replacing ~500 pole mount transformers (one-eighth of the total) during the planning period, aligned with expected pole renewals. This includes converting ~20 pole mounted units to ground mounted.

Our 10 year plan includes $30 m of distribution transformer renewals. By the end of the period we expect to have less than 1% of distribution transformers classified as H1.

We also assess the health of our voltage regulators based on age. When a voltage regulator reaches its time or operation-count limit it is removed from service and replaced with a unit from the pool of refurbished units (refer to spares management). Auto transformer condition is based primarily on oil testing; the results of this work indicate that the units are nearing end-of-life in line with their age profile.

As described in Chapter 8, our forecast expenditure on distribution transformer ramps up to RY25, continuing at that level for the remainder of the planning period. The bulk of the expenditure relates to replacement of larger poor condition pole mounted transformers with ground mounted units.

Asset Performance and Risks

The performance of our distribution transformers has been generally good over the past decade, with these assets contributing an annual average of only 2-3% of total SAIFI. Risks associated with distribution transformers include oil leakage, and seismic risk. Overloaded transformers can cause power quality breaches and reduce the life of the transformer. There is a risk of live terminals on ground mounted units being exposed in the event of vehicle collision, vandalism, or failure of kiosk enclosures/doors that are in poor condition. This is a major concern and we have inspection programmes planned to quantify this issue and to determine mitigation measures.

As a result of amendments to our network design standards to address seismic risk and improve resilience, we are replacing our larger pole mounted units with ground mounted configurations when they become due for renewal. This will also deliver operational benefits. Replacing pole mounted units with ground mounted units is considerably more costly than a like-for-like replacement.

We have initiated a project to remove or refurbish all underground distribution transformers based on design issues and poor resilience. These transformers are prone to flooding and the confined space makes access for operation and maintenance problematic.[68] This also raises safety issues, and we plan to replace these with modern assets where possible. Where it is not possible, the switchgear will be removed or set up for remote operation.

Our mobile distribution substations have seen many years of operation and their performance has deteriorated in recent years. In 2015 we repaired or replaced major components such as LV boards, and we have spent considerable effort on reducing the hazards associated with installation. However, some risks remain and we believe these assets are nearing end-of-life. We plan to replace two of them during the planning period.

68 These assets are not accounted for in the ground mounted distribution transformers health chart as we have not yet identified how many are affected.

5.8.3. Maintenance Approach

We use a combination of maintenance approaches for these assets. Though we undertake a variety of preventive work, most of the work volume is reactive.

Preventive Maintenance

We carry out limited tests on larger ground mounted units, the results of which help us better assess condition. This supports forecasting and prioritisation of renewals. We plan to improve the condition assessment regime for ground mounted transformers. Key preventive maintenance tasks for this sub-fleet are set out in Table 5.22.

Table 5.22: Distribution Transformers Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
Ground mounted distribution transformers	Underground sub-station visual inspections	Identify visually apparent defects, clear rubbish, check oil levels, check operability	Three monthly
	Condition assessment	Visual inspection to assess rust/oil leaks. Kiosk integrity evaluated, secondary protective screens placed in front of fuse ways, door locks assessed	Three yearly
	Dissolved Gas Analysis (DGA) testing	Routine oil dielectric tests on underground/in-building assets to evaluate condition of oil. DGA testing to identify the presence of internal faults . Frequency depends on location of the unit	One to five yearly
	MDI Readings	Maximum demand indicator readings tell us how highly loaded a transformer is	Annually
Pole mounted distribution transformers	Visual inspection (as part of pole inspections)	To assess rust/oil leaks	Five yearly
Voltage regulators	Visual inspection and thermographic testing	Visual inspection to assess rust/oil leaks, prove functionality by exercising the tap changer/recording the event log. Thermographic testing to identify faults	Annually (new regime)
	Maintenance service	To ensure continuing operation and reliability. Timing varies depending whether the VR is heavily or lightly loaded	4-10 yearly or 100,000-120,000 operations
Mobile distribution substations	Inspection	To ensure the optimal operating condition of the mobile distribution substation is maintained	Six monthly
	Return from service inspection	To ensure the mobile substation is in working order	Whenever returned from field
Mobile generators	Mobile generator inspections	Confirm operability and condition	Monthly

Corrective and Reactive Maintenance

Corrective and reactive maintenance on these assets is carried out as needed. In most cases we replace small pole mounted distribution transformers only upon failure.

Spares Management

We maintain a rotable spares pool for voltage regulators. Voltage regulators are removed from service based on number of operations (refer Table 5.22), and replaced with units from the spares pool. If it is economic to do so, the removed unit is serviced and returned to the spares pool. Otherwise it will be disposed of, retaining components as spare parts as needed. This approach requires monitoring and adding to inventory at times so that sufficient spares are always available.

We maintain strategic spare pole and ground mounted units. We maintain an inventory of small pole mounted transformers as these are replaced on failure.

5.8.4. Renewals and Refurbishment

Table 5.23 provides a summary of our renewal approach for our distribution transformer assets.

Table 5.23: Summary of Distribution Transformers Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition
Medium term forecast (renewal volume)	Asset health (age), pole replacement projects
Cost estimation	Volumetric

Capex Investment Drivers

The main drivers of forecast Capex investments in distribution transformer assets is age. We forecast renewals based on condition only for mobile distribution substations and auto transformers at this time.

During the planning period our focus will be on replacement of poor condition pole mounted units, particularly replacement of units of 200 kVA or larger with ground mounted units in line with our revised design standard.

We will continue to refurbish our voltage regulators and return them to service until such time as this is no longer cost effective. Replacement of the auto transformer at Momona is planned for 2019.

We will be replacing a reasonable proportion of pole-mounted transformers proactively during pole replacement works. Transformers are replaced along with poles and crossarm assemblies, with the removed asset assessed for refurbishment or disposal.

Forecasting Approach

We use a volumetric approach to forecasting distribution transformer renewals, with unit rates based on the current replacement costs of units of the same configuration and rated voltage.

5.9. Zone Substations

This section describes our Zone Substations fleet and summarises our management plan for the fleet.

5.9.1. Overview of Fleet

The fleet includes four asset types:

- Power transformers
- Switchgear
- Buildings
- Ancillary equipment.

Zone substations (example photo on the right) take supply from the national grid through subtransmission feeders. They provide connection points between subtransmission circuits, step-down voltage through power transformers to distribution levels, and incorporate switching and isolation equipment to enable operation of the network. Supply for many thousands of customers depends on a few key assets within zone substations. Our zone substations are high-value critical assets within our network, and prudent management is essential to ensure safe and reliable operation.

Power transformers (example photo below) are used to transform power supply from one voltage level to another, generally (but not always) 33/11 kV. These units are generally equipped with on-load tap changers to assist with maintaining the required voltage. Typically, large zone substations have two transformers. Modern designs incorporate bunds to contain oil spills and fire walls between the transformers (where necessary), to minimise the risk of fire spreading in the event of catastrophic failure. Power transformers typically comprise the core and windings, housing (tank), bushings, cable boxes, insulating oil, conservator and management systems, breather, cooling systems and tap changing mechanisms.

Zone substation switchgear has a primary function of isolating and connecting supply to feeder circuits, which in turn supply neighbourhoods. It includes circuit breakers, switches, and other equipment, and typically operates at 66 kV, 33 kV, 11 kV and 6.6 kV. Switchgear may be contained within the zone substation building (individual switchgear panels assembled into a switchboard), or installed in an outdoor switchyard. Outdoor switchgear typically includes ABSs, earth switches, circuit breakers, reclosers and standalone current and voltage transformers.

Zone substation buildings mainly house protection, communications and indoor switchgear equipment, and 1050 Hz ripple plant. Buildings and grounds must provide security for the equipment contained within, be well secured for earthquake exposure and adequately earthed. This sub-fleet includes fences, security and access ways to the sites.

Ancillary equipment comprises earthing/earth grids, neutral earthing resistors (NERs), cables and structures (bus work, stands) within zone substations, load control plant and receiver relays, local service transformers and LVAC supplies, surge arresters, and the mobile substation. Load control equipment in the zone substation enables us to send audio frequency signals to receivers around the network. Earthing grids protect against hazardous touch, step and transfer potentials during fault conditions, while NERs reduce the current occurring due to earth faults.

The 5 MVA mobile substation provides a backup for zone substation outages or power transformer maintenance. Due to its size, the setup is on a four axle stepped semi-trailer with front and rear outriggers for levelling and stabilising when deployed.

Box 5.14: Fleet Objectives

The performance of these assets is essential for maintaining a safe and reliable network.

We have established the following objectives for the zone substations asset fleet:

- Zone substation buildings remain intact and able to support provision of essential post-disaster services, in the event of a seismic event
- We use switchgear arc flash risk assessments, together with condition, to prioritise renewals
- Systematic analysis of failures provides reliable feedback to inform asset planning decisions

Population

There are 39 permanent zone substations – 18 in Dunedin and 21 in Central. We have 63 power transformers and one mobile substation. Table 5.24 sets out the number of power transformer and switchgear assets in our zone substation fleets.

Table 5.24: Zone Substation Population (as at 1 June 2018) [69]

	Operating Voltage	Size (MVA)	Number of Units
Power transformers	11/33 kV	<10	18
		10-20	21
		20-30	20
	33/66 kV	<10	2
		20-30	2
Total			**63**

[69] Note that there are some data issues with our switchgear population. We expect to resolve these prior to AMP19.

	INTERRUPTING MEDIUM	6.6 KV	11 KV	33 KV	66 KV	TOTAL
Indoor circuit breakers	Oil	173	23	0	0	**196**
	SF_6	13	0	6	0	**19**
	Vacuum	39	93	0	0	**131**
	Total	**224**	**116**	**6**	**0**	**346**
Outdoor circuit breakers	Oil	1	9	17	0	**29**
	SF_6	0	6	2	6	**14**
	Vacuum	0	1	25	0	**24**
	Total	**1**	**16**	**44**	**6**	**67**
Pole mounted switches				**238**	**11**	**249**

In addition to the assets listed in the table above, we have 31 buildings at our zone substations, housing protection, SCADA, communications, 1050 Hz ripple plant and indoor switchgear equipment. We also have one 5 MVA mobile substation which is used for zone substation backup or to allow transformer maintenance.

In Dunedin we operate two ripple injection load control systems in parallel, controlled via the Dunedin SCADA master station. A solid state 317 Hz system injects into the subtransmission, while the aged K22/Decabit 1050 Hz ripple injection system (comprising 18 injection plants) injects into distribution circuits via rotary injection equipment located at each zone substation. We are progressively removing the older plant as we refurbish or renew each zone substation, and working with metering equipment owners on prioritising and expediting ripple relay replacement to enable this. We own only the streetlighting ripple relays of which we have replaced all but the most difficult ones. We have an additional three Decabit 317 Hz solid state ripple injection plants in Central.

Box 5.15: Mobile substation

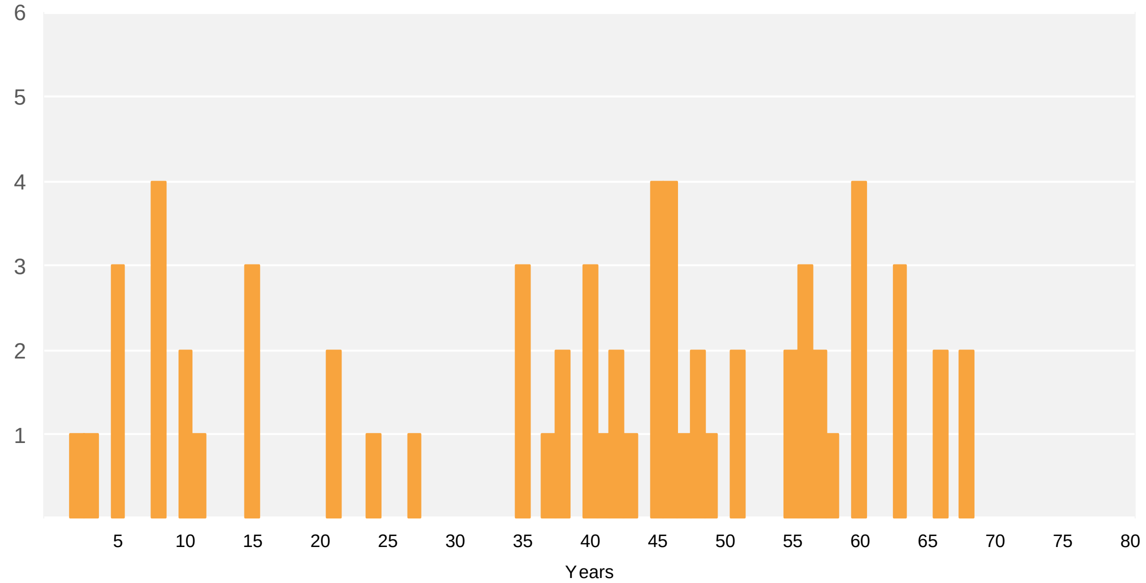
A number of our rural zone substations have a single power transformer. While we have some ability to shift load between substations, obtaining shutdowns to enable maintenance is often difficult. Any maintenance or other planned work requires an outage for the communities supplied by those substations. A mobile substation can reduce or even eliminate the need for outages. We purchased a 5 MVA unit about ten years ago and have made a number of our single transformer substations mobile-capable. Additional substations will be made mobile-capable as needed.

Age Profiles

The average age of our zone substation transformers is 38 years, against a nominal life expectancy of 55 years. Our Dunedin transformers have a substantially higher average age than those in Central.

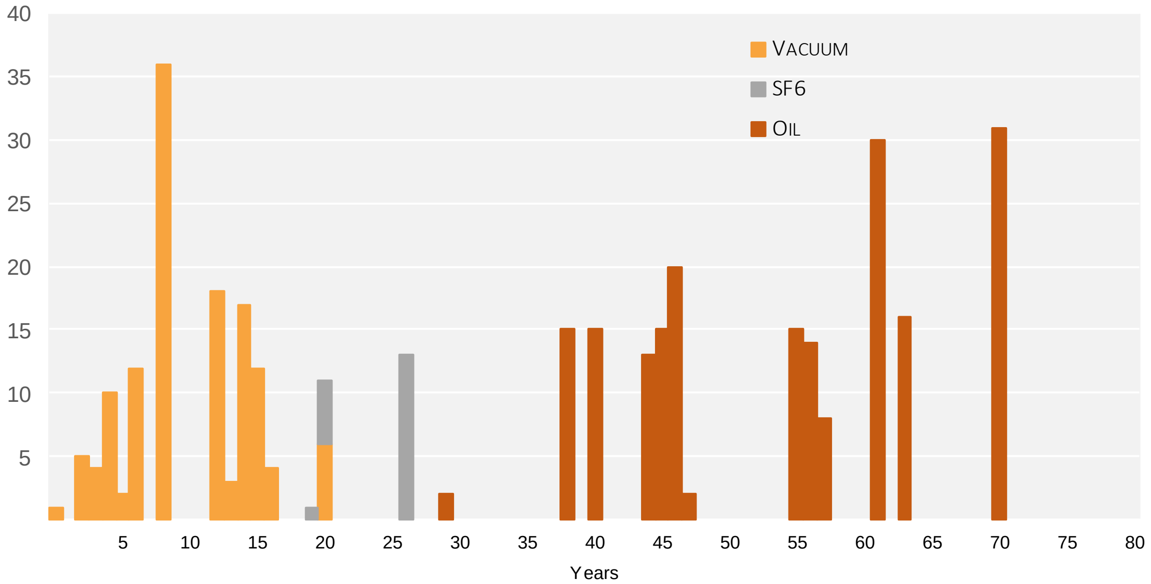
In Dunedin, four power transformers exceed 65 years. Two of these will be replaced as part of the new Carisbrook zone substation in 2018, while the other two are part of zone substation upgrades later in the period. Figure 5.29 shows the age profile of our power transformers.

Figure 5.29: Zone Substation Age Profile – Power Transformers (as at 1 June 2018)



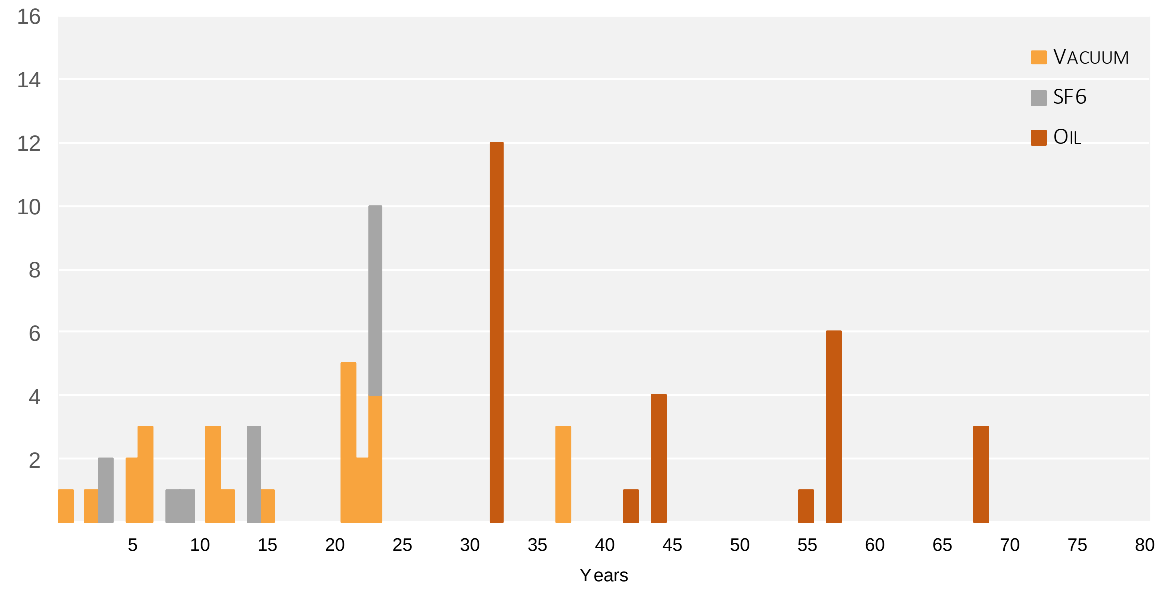
Switchgear technology has evolved over time. Prior to the 1990s the majority of circuit breakers used oil as the insulation medium, and these make up most of our current populations. Oil-based circuit breakers carry additional risks compared to their modern equivalents. Modern switchgear uses vacuum or SF_6-based circuit breakers. The level of arc flash containment and protection has improved significantly with modern switchboards. The figures below show the age profiles, individually, for indoor and outdoor switchgear and for pole mounted switches. The life expectancy of our indoor switchgear is 50-60 years, so we expect to replace a significant number of these over the planning period.

Figure 5.30: Zone Substation Age Profile – Indoor Switchgear (as at 1 June 2018)[70]



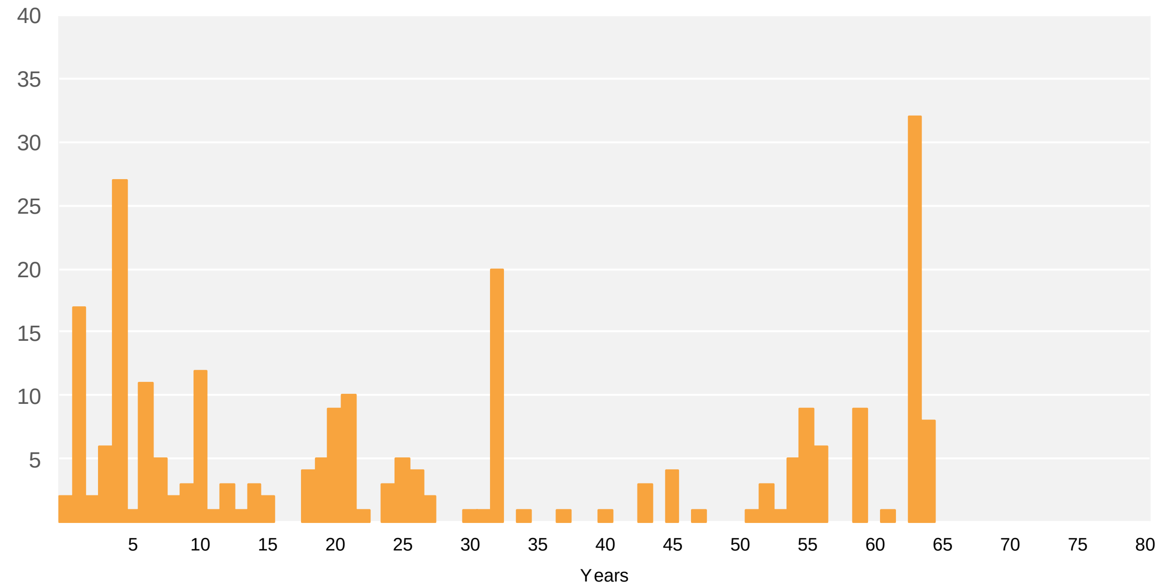
[70] Note that some of the circuit breakers shown as vacuum-type have an oil insulating medium, which requires additional maintenance compared to their "pure vacuum" counterparts.

Figure 5.31: Zone Substation Age Profile – Outdoor Switchgear (as at 1 June 2018)



Expected life for our outdoor switchgear is 40-50 years. On this basis we expect that a number of our outdoor oil-insulated circuit breakers and pole mounted switches will need replacement over the planning period.

Figure 5.32: Zone Substation Age Profile – Pole mounted switches (as at 1 June 2018)



The buildings that house our zone substations range from new to 70+ years old. Most of the structures were established between 1950 and 1970. The older buildings are likely to require moderate to significant upgrades to meet today's seismic standards.

The 1050 Hz ripple injection plants in Dunedin have exceeded their expected lives. The 317 Hz plant which will replace them has been installed and is being operated in parallel while we progressively phase out the aged plant. The three 317 Hz injection units on the Central system have been upgraded over the past decade due to load growth and age. We have replaced the ripple receiver relays owned by Aurora to work with the new system.

5.9.2. Condition, Performance and Risk

In 2015, we carried out comprehensive fire, security and seismic risk assessments for substation assets at 29 of our zone substations. As expected, the newer assets generally have better seismic strength and older assets are much more likely to be under-strength.

In 2018 we commissioned a one-off non-intrusive inspection of our 39 zone substations to check the infrastructure, ancillaries, protection, control and measurements, circuit breakers, instrument transformers and power transformers. The objective was to assess the condition of zone substations and highlight any deficiencies, large or small. Examples include oil leaks, missing test results, corrosion, lack of signage, lack of earthing and site security. Results also indicate which tasks require immediate attention versus those that can be integrated into our medium term plans for the zone substations.

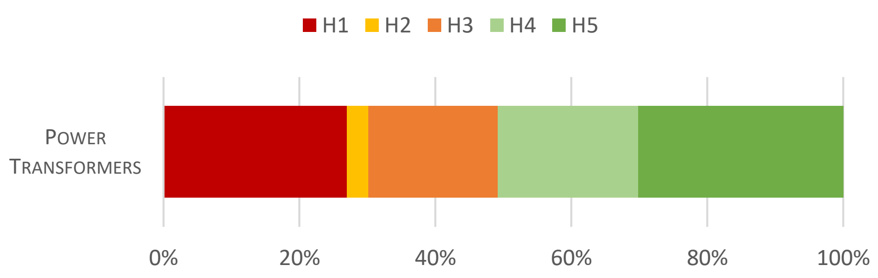
We carry out various tests and condition assessments of our major zone substation assets, such as our annual oil dissolved gas analysis and four-yearly total oil condition analysis for our transformers. The outcomes of such tests are combined with information from the zone substation inspections and seismic assessments to determine renewal and refurbishment needs.

Zone substation transformers

The internal condition of power transformers cannot be directly observed, economically. The main drivers of issues related to deteriorating condition are age, tap changer failures, corrosion and leaking gaskets. We use a variety of oil tests including Dissolved Gas Analysis (DGA) and Furans to help us understand how transformers are ageing internally and indicate any systemic issues. We also gather information on the external condition of components and any known issues.

Our current asset health model is a simple age-based model and does not take this measured and observed condition information into account. Going forward we plan to develop a health model that incorporates condition together with other risks such as unavailability of spares, failure to meet seismic standards, and known type issues which present performance or safety risk. Figure 5.33 shows the asset health of our power transformers fleet.

Figure 5.33: Zone Substation Asset Health – Power Transformers (as at 31 March 2018)



Box 5.16: Investment Plans

To manage risk associated with our power transformers we are:

- replacing 19 power transformers based on asset health (including age and condition assessment), and additional units as part of system growth upgrades (refer to Chapter 6)
- replacing all units classified as H1 during the planning period, unless revised condition information enables replacement to be deferred
- replacing most of the H2 and H3 classified units during the planning period, unless revised condition information enables replacement to be deferred.

Power transformer failures can be of high reliability consequence if located at a single-transformer zone substation. We believe that our current replacement plan is sufficient to manage risk taking account of dual transformer substations, contingency plans and the mobile substation.

Our 10 year plan includes $20 m of renewals. By the end of the period we expect to have 7 power transformers in service classified as H1 (units that are currently H2 or H3).

Our forecast (refer Chapter 8) makes provision for replacing power transformers as described in the table above. Our preliminary prioritisation of works has deferred lower criticality replacements at dual transformer sites which have back-up from surrounding substations. However, note that the asset health scores are based on age which we believe to be somewhat conservative; based on actual condition we expect few H1-H3s to be remaining by the end of the period.

The criticality of power transformers is limited to reliability performance. Units at single-transformer substations are critical assets and must be highly reliable. Our performance history has been generally satisfactory, but we have experienced tap changer failures resulting in operational constraints.

It may be possible to improve a power transformer's asset health score through refurbishment. When determining whether replacement is warranted or can be deferred, the costs and benefits of carrying out such life extending works are taken into consideration. A power transformer may be replaced by itself, or as part of a wider zone substation upgrade, depending on the condition and performance of other assets that make up the substation.

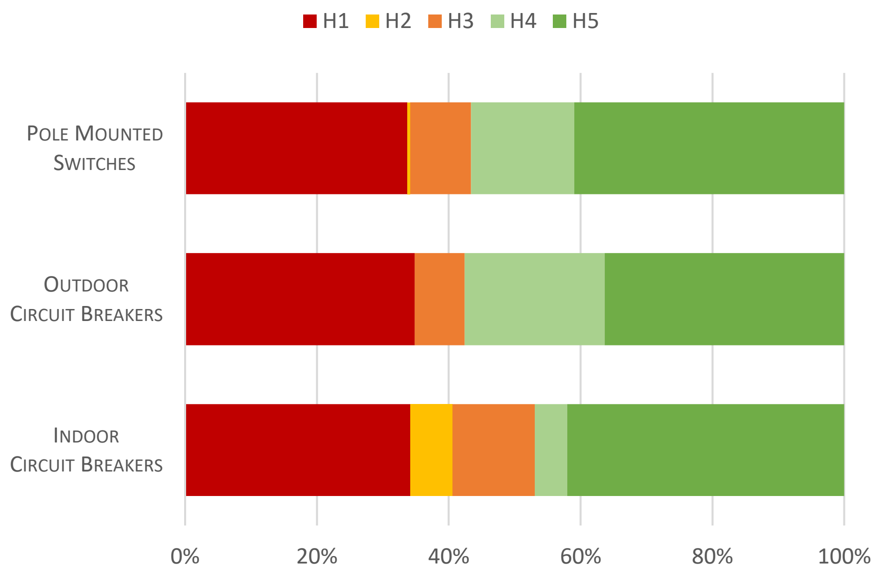
For some of our power transformers we will investigate whether a workshop-based mid-life refurbishment is appropriate to extend its life. A number of our power transformers are relatively small and low cost which may make refurbishment less appropriate.

While expected to withstand a moderate seismic event, many of our older power transformers and their foundations have been rated below 100% of the New Building Standard (NBS) for IL3, and could be vulnerable in the event of a significant earthquake. We plan to carry out work to manage this risk where economically justified and feasible, and where we do not plan to replace the transformers in the near future. This includes the use of seismic restraints/hold downs and foundation strengthening.

Zone substation switchgear

The main drivers of deterioration of our switchgear assets are age, number of operations and condition of internal components such as instrument transformers. Outdoor switchgear is more prone to corrosion and damage due to wind-blown debris, birds and vandalism than indoor equipment. The following chart sets out the asset health of our zone substation switchgear – split into indoor and outdoor circuit breakers and air break switches – based on a combination of age and type issues (described below).

Figure 5.34: Zone Substation Asset Health – Indoor and Outdoor Circuit Breakers, Air Break Switches (31 March 2018)



Box 5.17: Investment Plans

To manage risk associated with our zone substation switchgear we are:

- replacing ~190 indoor/outdoor circuit breakers – approximately 50% of the sub-fleet – over the planning period
- replacing approximately 64 (25%) of our pole mounted switches over the same period
- removing some additional end of life (H1) switches from service as a result of converting outdoor switchgear to indoor
- continuing to adjust our investment plans to best manage the reliability and safety risks associated with circuit breakers and the operational consequences of switches, recognising that circuit breakers are generally higher criticality than switches.

Total renewals expenditure of $27 m over the planning period will lead to less than 1% of our zone substation switchgear being classified as end of life (H1).

Our zone substations Capex forecast is shown in Chapter 8. Buildings are allowed for in the forecast in alignment with switchgear renewals where physical space to accommodate new switchgear is expected to be an issue.

Oil-based circuit breakers carry greater risks than the modern equivalents. Likelihood of failure increases with operating frequency and energy of switching. Servicing oil circuit breakers based on the number and severity of faults they have experienced (refer Table 5.27) is intended to minimise failure risk. However, it can be difficult to service some of our older oil-filled switchgear due to lack of spares – requiring us to seek parts from withdrawn units, or manufacture parts – such that they now have high operation counts. It may be possible to 'catch up' on maintenance, but this will be more risky for older assets, and replacement of these is likely to be warranted. Outages to maintain these older units may also need to be longer than for switchgear that has readily available spares in the market. We are investigating our options with regard to these assets.

We have identified the following type issues with our zone substation switchgear.

Table 5.25: Zone Substation Type Issues – Switchgear

ASSET TYPE	ISSUE
Outdoor Cooper 33 kV (VWVE) oil-immersed vacuum circuit breakers	Failure of bushing extension seals due to incorrect fitting has allowed moisture ingress, into the oil
Older indoor switchgear	Lack of arc containment is a safety issue. It can be managed to a degree by remote operation and retrofitting
Oil-filled circuit breakers	Safety issue – higher consequence of failure than other types
Canterbury Engineering type 2-piece insulator ABSs	Two piece insulator with cement failure. We are addressing this either by reactive replacement of the full ABS, or upgrading them as needed

Arc flash risk is a significant safety concern for our indoor switchgear assets. An arc flash is a type of electrical explosion that can release a large amount of energy. It can cause material damage, and serious injury or even death. New switchgear has full arc flash detection systems and arc containment and may have arc venting.

With older equipment we partially mitigate the risk using the following approaches:

- Removing the switchboard from service to perform maintenance
- Reconfiguring the upstream network to reduce potential arc flash levels
- Ensuring personnel working close to the equipment wear appropriate arc flash rated PPE
- Carrying out operations via SCADA with personnel outside of the switch room.

These approaches do not entirely eliminate arc flash risk, and arc flash retrofits or full switchgear replacement may be required to achieve this. We plan to carry out a full assessment of arc flash risk (based on potential incident energy and switchgear type) across all our non-compliant switchboards. This will provide further guidance to our renewals work programme.

Like transformers, switchgear also carries seismic risk. In a recent seismic assessment, the hold-down fixings of many of our switchgear assets were found to be understrength, and we plan to rectify this in a number of cases where this is feasible and where renewal of the assets is not planned within the forecasting period.

We have not had any significant performance issues with our switchgear. However, our understanding of performance is limited by the available data. We plan to improve the capture and analysis of fault and defect data to support ongoing performance monitoring.

Buildings

Our buildings and grounds are exposed to vandalism, fire, natural disaster events and changes in compliance requirements. Our zone substation buildings are up to 70 years of age. Seismic assessments have found that 20 of 26 zone substation buildings assessed do not fully meet the Importance Level 3 (IL3) standard.[71] Most of the lower rated buildings were built prior to 1970.

Table 5.26 shows our buildings by NZSEE Seismic Grade/New Building Standard (NBS) range.

Table 5.26: Zone Substation Buildings – Seismic ratings (as at 1 June 2018)

NZSEE GRADE	RATING (%NBS)	NUMBER OF BUILDINGS
A+	>100	6
A	80-100	6
B	67-79	1
C	34-66	5
D	20-33	7
E	<20	1
Not assessed [72]		5
Total		**31**

We plan to replace the buildings at four of the lowest rated zone substations, and undertake reinforcements such as strengthening of masonry of a further eight. The building at North City is to be made redundant or relocated due to the new Dunedin Hospital.

New buildings will be designed to an IL4 standard. We have developed detailed designs for seismic strength upgrades of existing buildings to 100% of the New Building Standard (NBS) for the IL3 standard.

Security of our zone substations is critical for public safety. The master key for our locks in the Dunedin network has recently come out of patent, reducing the level of security we can maintain. We plan to implement a programme of security upgrades at our zone substations over the next three years, to ensure that access is able to be appropriately managed, in a manner that meets our obligations under the Electricity (Safety) Regulations.

Ancillary equipment

We currently use load control equipment to manage up to 38 MW of load at peak periods, and this supports deferral of network investment. However, performance of the ripple systems is dependent on the performance of the controlling systems, communications, and ripple receiver relay installations. Our progressive replacement of Dunedin's aged, deteriorating 1050 Hz system with the new 317 Hz plant, together with upgrades that are being made to the communications networks will improve the service. The ripple plant in Central is relatively new and is performing as expected.

Our 5 MVA mobile substation is relatively new and we do not anticipate any performance issues. We plan to construct mobile substation parking bays at three additional N security sites during the planning period to improve supply security.

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71 IL3 was adopted following evaluation of legislative requirements and industry practice. IL3 implies that the design level earthquake has a return period of 1,000 years for the Ultimate Limit State and 25 years for the Serviceability Limit State. We understand that typically distribution companies design to IL3, while Transpower designs to IL4.

72 Buildings that were constructed or strengthened recently or which are scheduled for demolition/replacement were not included in this assessment.

5.9.3. Maintenance Approach

We maintain our zone substation assets using a combination of preventive and corrective maintenance.

Preventive Maintenance

Table 5.27 sets out key preventive maintenance tasks for our zone substation assets.

Table 5.27: Zone Substation Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
Power transformers	Oil level recordings	Record oil levels for monitoring	Two-weekly
	Ground level inspection	To identify apparent defects in the tank/ pipework including oil leaks, check thermometer, and to ensure pumps and fans are operating correctly and record tap changer cyclo	Monthly
	Oil tests and DGA testing	Routine oil dielectric tests to evaluate condition of oil. Dissolved gas analysis to identify the presence of internal faults. Furan analysis to evaluate the rate of transformer ageing	Annually
	Transformer out-of-service maintenance	Detailed close visual inspection of bushings, pipework and systems. Confirm correct operation of cooling systems. Repair minor damage/rust/leaks	Four-yearly
	Tap changer refurbishment	Occurs after set number of operations to ensure continuing operation and reliability of tap changer	Manufacturer recommended, maximum three years
	Painting of outdoor 33 kV transformers		Ten-yearly
Zone substation switchgear	Visual inspection of circuit breakers	Check for signs of leakage, if applicable (SF_6, pressure and oil level), corrosion, tank distortion, broken porcelain, tracking on bushings, gap measurements	Monthly
	Thermal imaging of circuit breakers	To identify any hotspots which may indicate damage to the circuit breakers in order to prevent functional failure	Annually
	Partial discharge test – circuit breakers	Partial discharge measurement is carried out to assess the condition of the circuit breaker's solid insulation, and is used in determining remaining life	Half-life (20 years), then five-yearly thereafter
	Circuit breaker overhauls (oil breakers only)	Restore condition of circuit breaker contacts and insulating oil. Maintain/lubricate operating mechanism. Confirm correct operation of system. Prevent corrosion.	Four yearly
	Operation-based maintenance of oil circuit breakers	To ensure the continued operation of the circuit breaker following a certain number of fault operations	Three trips

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
	Air break switch visual inspections	Identify visually apparent defects, diagnostic testing, operational checks, check cement (two-piece) cleaning, minor repairs	Four yearly
Buildings, grounds and fencing	Substation grounds maintenance	Lawn mowing, weed management, security inspections	Two-weekly
	Fire protection inspection	Ensure the ripple injection CO2 fire protection system is in working order	Annually, pressure test every five years
	Asbestos testing	To detect airborne asbestos particles	Five yearly
Ancillary equipment	Comprehensive ripple equipment servicing	Ensure operability of signal generating equipment, associated motor starting contactors, signal impulsing contactors, signal injection equipment	One or two yearly (1050 and 317 Hz, respectively)
	Visual inspection and Earth grid testing	Verify integrity of earth grid	Five yearly
	Mobile substation inspection	To ensure the optimal operating condition is maintained	Six monthly
	Mobile substation return from service inspection	Return from service inspection to ensure it is in working order	When returned from the field

Corrective and Reactive Maintenance

We carry out corrective maintenance as needed to remedy issues identified during inspections. Reactive maintenance carried out as needed.

Spares Management

We retain strategic spares for most of our zone substation assets or components, for example, tap changers, switchgear, transformer bushings and surge arresters.

5.9.4. Renewals and Refurbishment

A large part of our forecast expenditure on zone substation assets relates to several full zone substation renewals. We expect to undertake this work in the middle of the planning period, with plans to be firmed up once we have gathered more condition information to support prioritisation. High risk switchboards and high-operation circuit breakers that have not been maintained will be replaced in line with asset health. Many of our power transformers are redundant (N-1) so the failure of one unit may not necessarily result in an outage. Over the next few years we will refine this forecast as we build on our risk and criticality framework for transformers.

Table 5.28 provides a summary of our renewal approach for our zone substation assets.

Table 5.28: Summary of Zone Substation Renewal Approach

Activity	Approach Used
Replacement basis	Condition/probability of failure and criticality
Medium term forecast (renewal volume)	Asset health, obsolescence
Cost estimation	Tailored for major projects, otherwise volumetric

Capex Investment Drivers

The main drivers of Capex investments in zone substation assets are:

- Condition/asset health
- Obsolescence
- Type issues
- Criticality of the asset or zone substation

A key programme during the planning period is to undertake seismic upgrades or refurbishments of our zone substation buildings, and power transformer and switchgear restraints and foundations.

Asset health indicates that a number of our power transformers are nearing end of life. Some of these will be replaced as part of planned zone substation upgrades. Substation upgrade plans have been developed taking into consideration condition of key assets, seismic review results, and load and security level at the substation. Others will be replaced as standalone projects.

Switchgear replacement programmes are driven by type (for example, removal of oil-based systems) and condition. As with power transformers, some of these replacements will take place as part of wider substation upgrades.

Other plant will be replaced as part of substation upgrades or Capex works, or individually as needed.

Forecasting Approach

We forecast building renewal and refurbishment costs and seismic works based on the individual site, as cost can vary significantly. For volumetric work within our zone substations, we use unit costs which vary by size or rating and are based on supplier costs. Installation costs are based on recent historical costs.

5.10. Secondary Systems

This section describes our Secondary Systems fleet and summarises our management plan for the fleet.

5.10.1. Overview of Fleet

The fleet includes the following sub-classes:

- Remote terminal units (RTUs)
- Protection Systems – protection relays, Automatic Voltage Regulators (AVRs) and panels
- DC systems – battery banks and chargers
- Meters.

RTUs are used for monitoring, control and data acquisition in real time. Protection equipment operates to protect primary equipment and ensure the safety of employees, service providers and the public in the event of electrical faults. Its reliable performance is critical. Over time we are transitioning from older technology electromechanical relays to modern, highly functional numerical relays.

Our DC supply systems provide a reliable and efficient power supply to the vital elements within our networks, for example, protection equipment, SCADA, metering, communications and security alarms. DC supplies are located within substations. The system consists of two main elements – batteries and chargers. Our metering assets comprise check metering at grid exit points (installed on the bus). These provide verification against Transpower's revenue meters.

Box 5.18: Fleet Objectives

Secondary systems are critical for enabling safe and efficient operation of our electricity networks. We have established the following objectives for the Secondary Systems asset fleet:

- No injuries resulting from incorrect operation of protection schemes.
- RTUs allow reliable control and monitoring of our networks at all times.
- Asset data about secondary systems is comprehensive, maintained up-to-date and is readily accessible to users through an effective asset information system

We have develop the following strategies to support these objectives:

- Type-based replacement of protection relays.
- Investigating new technology solutions to address legacy safety and performance issues

Population and Age

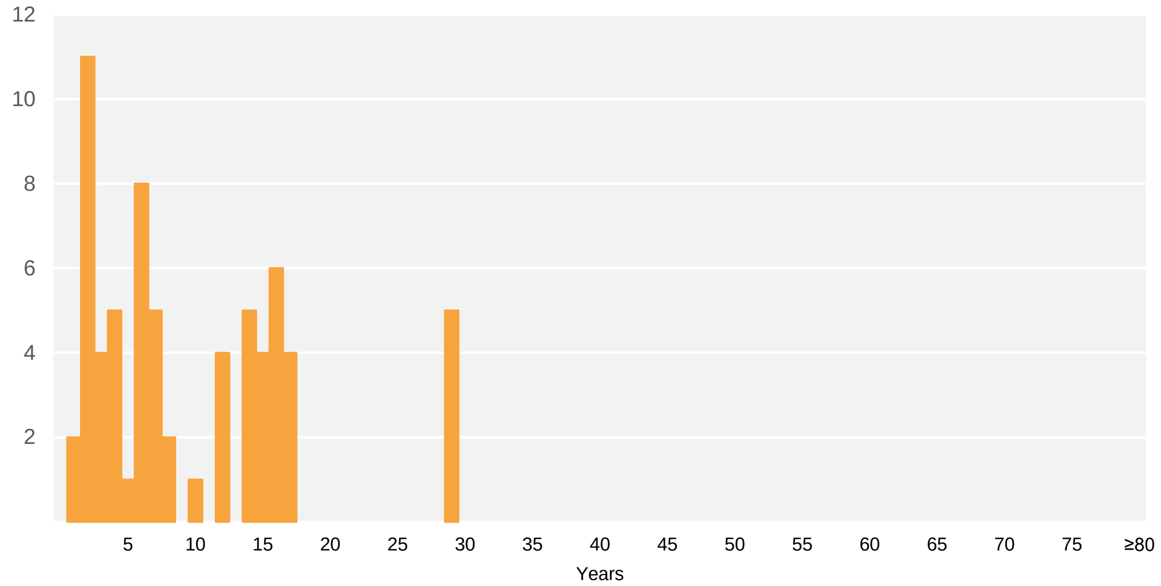
Our secondary systems population is set out in Table 5.29.

Table 5.29: Secondary Systems Population (as at 1 June 2018)

TYPE	SUB-TYPE	POPULATION
RTUs		67
Protection relays	Electromechanical	686
	Numerical	226
	Static	90
	Microprocessor	64
DC supplies	110 V Batteries	35
	<110 V Batteries	124
Meters		8

Following a comprehensive review of our SCADA, control and communication and protection systems, we undertook a project to upgrade these systems. In addition to providing new SCADA and communications equipment, this project has replaced some RTUs and protection equipment.

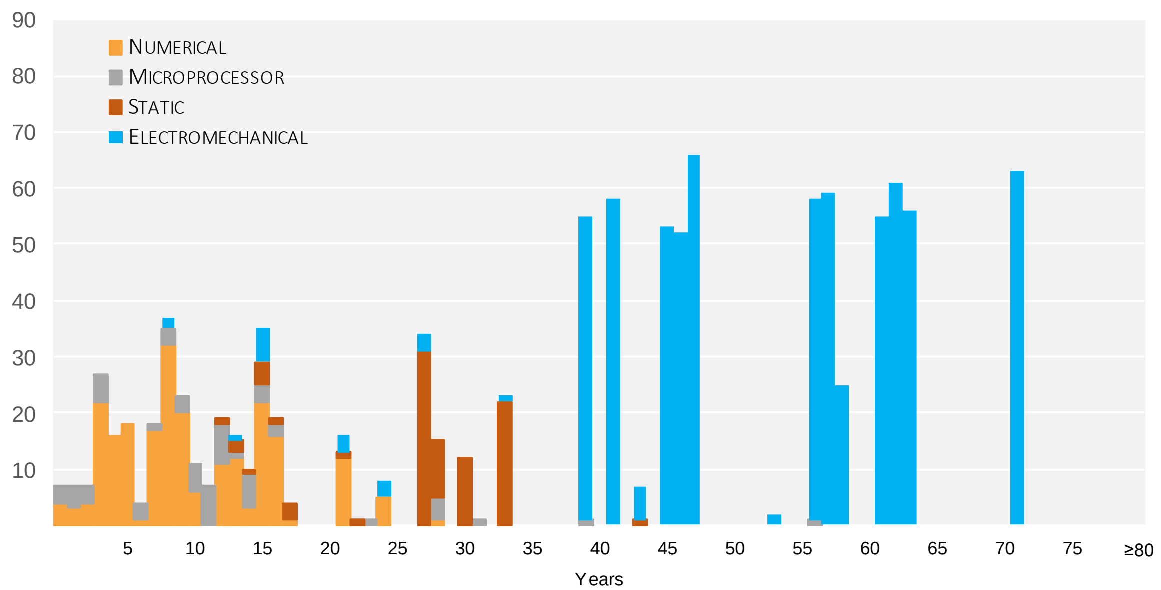
Figure 5.35: Secondary Systems Age Profile – RTUs (as at 1 June 2018)



A number of RTUs remain that have exceeded their expected life of 15 years, and we plan to replace further units (in addition to these) as part of zone substation upgrades.

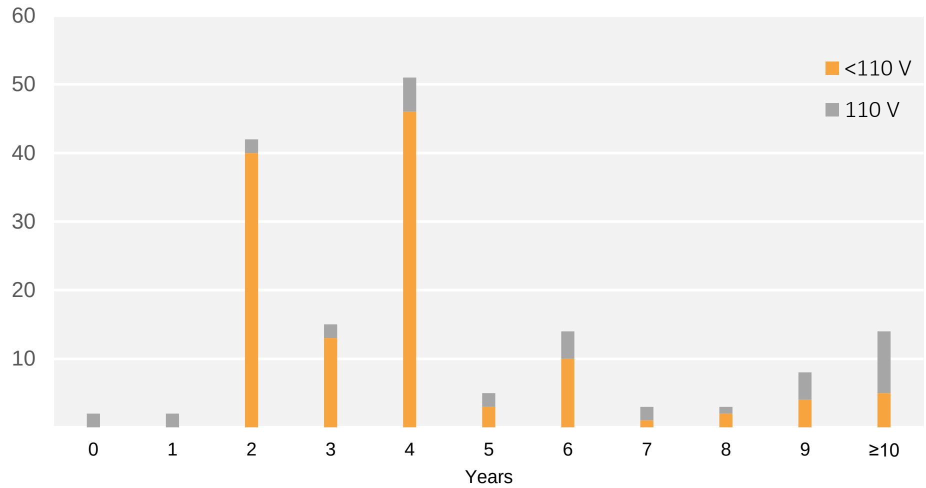
Our protection sub-fleet includes several types of protection schemes with different functions. These use four main relay types: static, electromechanical, numerical and microprocessor. Many of our electromechanical relays have exceeded their expected life of 40 years – some by a considerable time – and spares and/or manufacturer support are unavailable. The expected lives of numerical and static/microprocessor relays are 20 years, respectively. However the firmware upgrades needed for security or compatibility purposes, may no longer be available for these relays once they are out of manufacturer support. A large programme of work to replace electromechanical relays, in particular, is planned.

Figure 5.36: Secondary Systems Age Profile – Protection Relays (as at 1 June 2018)



Our batteries are predominantly lead acid, and provide DC supply at voltages from 12 V to 110 V, the latter mainly serving protection equipment. The lower voltages are mainly used for SCADA and communications. We aim to replace batteries once they reach eight years of age, if not already replaced based on condition – a number of our 110 V batteries within our Dunedin network exceed eight years of age, so have a higher risk of failure than younger units. Some of the DC supplies will be replaced as part of zone substation upgrades.

Figure 5.37: Secondary Systems Age Profile – DC Supplies (as at 1 June 2018)



5.10.2. Condition, Performance and Risk

Replacement of protection relays is mainly driven by obsolescence, or due to projects such as zone substation switchgear or transformer upgrades. Where a particular model shows signs of type failures (based on performance/condition) all relays of that model are replaced. Modern Intelligent Electronic Device (IED) relays make it easier to implement auto-reclose on feeders, improve performance and – because they can communicate directly with the SCADA RTU – provide additional fault data to enable detailed post-fault analysis.

Analysis of outage data and our public hazards register raised a small number of situations where equipment failures occurred but protection did not de-energise the circuit, resulting in an unsafe situation. This issue was raised by WSP in its recent risk review. It is not possible to determine which element caused incorrect operation, but where older electromechanical relays are involved it is likely the issues relate to these. We have been replacing these relays opportunistically but a sizable volume of aged relays remains. To better understand the risk associated with these assets we plan to undertake out-of-cycle functional testing of electromechanical relays in zone substations.[73]

Batteries are essential for supplying power to our substation secondary assets, including protection relays. These assets are required to operate not only during normal operation but also when the local AC service supply has failed. DC systems at the more critical substations have built in redundancy. If battery banks fail discharge testing and are uneconomic to repair, then we assess the entire bank for replacement.

[73] Note that zone substation projects (refer to Section 5.9) will include replacement of a portion of our electromechanical relays.

Box 5.19: Investment Plans

To manage risk associated with the assets protected by our secondary systems assets we are:

- replacing 795 protection relays and 69 battery banks and rectifiers
- prioritising replacements by balancing risk reduction against the need to coordinate protection replacement with other work at zone substations.

Our 10 year plan includes $17 m of renewals. By the end of the period we expect to have replaced all of our electromechanical and static relay sub-fleets. The expenditure also includes provision to upgrade our DC systems.

Type Issues

Our flooded lead acid type batteries have failed prematurely. This is due to sulphation in the electrolyte causing the external casing to bulge and crack, as well as high internal cell resistance. We have already replaced most batteries with this issue, and plan to replace the remaining few units in the near term.

5.10.3. Maintenance Approach

Maintenance of our secondary systems assets is primarily preventive, as set out in Table 5.30. Battery cell failures are usually identified during routine inspections or occur during diagnostic testing; failed cells are replaced immediately upon discovery.

Table 5.30: Secondary Systems Preventive Maintenance

SUB-FLEET	ACTIVITY	PURPOSE	INTERVAL
DC systems	110 V battery bank checks	Maximise the performance and service life of the batteries and ensure we know when our batteries are reaching the end of their useful life	Six-monthly/two-yearly (new regime)
Protection Systems	Routine testing of relays (generally limited to secondary injection tests)	To ensure proper protection of electrical systems and equipment	When associated primary equipment released for servicing
	Intertrip testing	Maintain the integrity of intertrip systems	Six monthly
	Electromechanical relay tuning	Tightening of mechanical spring	Four-yearly as part of zone substation inspection

Spares Management

We maintain spare relays in three locations around our networks, usually 2-3 of each relay type and model at most locations. When new types or models are introduced, spares are also purchased. We maintain spare RTUs and modules.

We do not maintain spare batteries as they lose charge over time, and our stores do not have the required temperature controls in place to maintain them in good condition. However, our arrangements with suppliers of batteries generally enable access to replacement cells at short notice.

5.10.4. Renewals and Refurbishment

As described in Chapter 8, our forecast expenditure on secondary system assets focuses on renewal of old electromechanical and static relays and DC systems. Expenditure is aligned with zone substation projects where possible, and ranges from $1-3 million per annum. Table 5.31 provides a summary of our renewal approach for secondary systems assets.

Table 5.31: Summary of Secondary Systems Renewal Approach

ACTIVITY	APPROACH USED
Replacement basis	Condition/obsolescence, performance
Medium term forecast (renewal volume)	Asset health, obsolescence
Cost estimation	Volumetric

Capex Investment Drivers

Key drivers for replacement are: obsolescence; asset health; and type issues.

We plan to replace a considerable number of protection and voltage control relays, control panels, batteries and RTUs in a number of our zone substations during the planning period, as part of wider zone substation upgrades, including power transformers and switchgear replacement projects. We will also be replacing end of life batteries, RTUs and protection relays separately from these wider projects as warranted by age, condition and type issues. In particular, we plan to replace all of our electromechanical and static relays.

Renewal and Refurbishment Forecast

Our secondary systems renewals forecast is volumetric. Unit rates are based on manufacturer unit costs and recent historical installation costs.

5.11. VEGETATION MANAGEMENT

Vegetation in close proximity to power networks can have a significant impact on network reliability and safety. Tree contact with power lines is a frequent cause of unplanned outages. In such situations, arcing erodes the conductor until its mechanical strength is no longer able to withstand the tension. Vegetation contact also poses a major hazard by conducting electricity, which may cause injury or death from earth potential rise.

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.

5.11.1. Objectives and strategies

Since 2013 we have placed significant emphasis on vegetation management, including moving toward a more systematic approach to identifying and remediating vegetation hazards.[74]

Box 5.20: Vegetation Management Objective and Strategy

Our objective is to focus on good practice vegetation management in order that vegetation is managed on a cyclical basis across our entire network by 2023 (at the latest), in compliance with the Electricity (Hazards from Trees) Regulations 2003.

This will have a number of benefits including reducing vegetation-related supply interruptions and safety hazards, improved landowner relations and improved efficiency and effectiveness of our vegetation management programme.

We have refocussed our strategy in line with achieving this objective. Our strategy involves:

- Moving to a full cyclical programme of work across the entire network.[75] For areas of the network which have not been monitored within the current work programme, work will be prioritised on the basis of criticality.
- Seeking best outcomes in terms of clearance distances, through liaison improvements, and by increasing direct interaction with tree owners to negotiate greater than mandated clearances.
- Developing and delivering an improved communications programme to make tree owners aware of the safety issues and their responsibilities regarding trees.
- Encouraging our contractors to establish a high performing safety culture.

Our vegetation management programme is critical to delivering reliable energy supply to our customers, meeting our safety and legislative[76] obligations and reliability targets, and ensuring a proactive and trusted relationship within our communities.

Over the medium-term we expect to build on the above initiatives to further improve our vegetation management approach.

- Reviewing and adjusting our cyclical plan to optimise efficiency, such as recognising varying growth conditions. This may result in longer or shorter cycles on parts of the network.
- Implementing a risk-based work programme dealing with management of fall zone and hazardous trees (in parallel with the cyclical programme).
- Developing tools to enable historic agreements and easement data to be made available to field liaison personnel, and evaluating emerging survey techniques that are becoming cost effective.
- Introducing contestability to improve cost effectiveness and efficiency.
- Establishing a vegetation management system as a means to drive analytics / identify gaps and efficiency opportunities.

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74 A review of historical quality breaches found that the increasing trend in tree contacts is likely to have been the result of lower than optimum necessary investment in vegetation control, and that achieving good network performance requires (among other things) committing adequate resourcing to effectively maintain tree contact risk at manageable levels.

75 Best performing electricity network companies have a 3-5 year vegetation management cycle.

76 The Electricity (Hazards from Trees) Regulations 2003 require us to identify trees or vegetation that is within the growth limit zone of any network conductor and to issue a notice to the tree owner advising of trimming/clearance requirements. These regulations specify both the tree owners' and our responsibilities with regard to actions and cost.

5.11.2. Vegetation management status

Our work in recent years has focussed on managing the vegetation management zones defined in the Electricity (Hazards from Trees) Regulations. We have prioritised cyclical work as follows:

- subtransmission circuits
- worst performing HV/LV feeders due to vegetation impact on reliability[77], and circuits identified as having the potential for vegetation to become a hazard to the public or our network, over time
- long rural circuits
- all other circuits.

Our cyclical vegetation management programme over the past two years has achieved the following in relation to the regulated zones:

- subtransmission: we have undertaken liaison activities as required, followed by tree trimming and removal and spraying programmes within the regulated zones around all of our subtransmission circuits. These areas are now subject to six monthly inspections/monitoring.
- Distribution and LV: We have undertaken liaison activities, tree trimming/removal and spraying around circuits associated with about 20% of our worst performing feeders.[78]
- We have addressed identified vegetation infringements involving approximately 2,000 additional tree sites, outside the circuits described above.

5.11.3. Performance and Risk

Outages resulting from vegetation touching power lines are a significant contributor to our overall SAIFI. This impact is greater in Central Otago where, in contrast to Dunedin's largely urban network, longer exposed overhead spans are typically skirted by road-side tree lines and wind breaks.

Appropriate planning and management is effective in reducing these vegetation-related outages, and in reducing the risk that tree contact with lines will result in injury or death of workers or members of the public. However, as a considerable number of our lines have not yet been inspected and managed within the current cycle, the risk of tree contact incidents will remain elevated for some time.

In addition, trees that sit outside the regulated zones prescribed in the Electricity (Hazards from Trees) Regulations 2003 but are within the fall-zone represent a risk to our assets. It is likely that these fall-zone trees are currently responsible for a considerable number of tree-related outages. Such trees are not included in normal cyclical work due to the legal complexity surrounding them, and we manage them on a case-by-case basis. In line with our strategy we plan to put additional focus on liaising with landowners to manage this risk going forward.

Additional risks that may result in tree-related issues include the drier conditions we have experienced in some years – which increase fire risk – and the increase in the frequency of major storm events over the past decade. Storms increase the risk of trees in the fall zone impacting our lines and the likelihood

[77] Worst performing feeders are determined using analysis of Feeder Average Interruption Duration and Frequency Indices (FAIDI and FAIFI) due to vegetation contact events.

[78] Note that feeders are not equal as they vary by length, type, operational location complexity and other factors.

of wind-borne debris. If such storm events continue to increase in frequency, this will have further implications in terms of tree-related outages.[79]

5.11.4. Delivery of vegetation management services

Our vegetation management programme comprises inspections and active management of identified issues and risks. This work is currently undertaken by the Tree Services business unit within Delta Utilities, though we plan to make this work contestable.

We are developing a tool for satellite-based vegetation survey, which we can use to cross-check circuits we believe to be under cyclical management, and to assist with identifying higher risk areas that are not identified by the worst performing feeder analysis. However, satellite imagery does not provide information on height of vegetation, and we are considering whether aerial survey may be needed to provide the required data to support our vegetation management programme.

Outside the cyclical work, we carry out reactive work and risk-based work in relation to fall zone and hazardous trees. Such work may be identified by field crews, targeted vegetation surveys and pole inspections, or based on local characteristics. Priority for this work will be based on criticality, such as sites near schools, playgrounds or parks, 'red zones' in the Central network (from which there are only one exit route in the event of fire) and locations supplied by a single line.

In planning our work programme, we may bring forward work where there are opportunities to improve efficiency or usefully collaborate with third parties undertaking related work.

5.11.5. Forecasting Approach

Our forecasts are currently based on the number of vegetation management and liaison teams we are operating. This recognises an expedited approach where we are completing as much work as possible given the available resources.

We plan to introduce contestability into vegetation management, and move to forecasting costs based on estimated number of kilometres of vegetation management work needed and unit rates agreed with our service providers.

5.12. ASSET RELOCATIONS

Our assets are often located alongside other infrastructure such as roads, water pipes, and telecommunications cables. At times, the owners of this infrastructure (for example, KiwiRail, NTZA and local councils) may need us to move our assets, generally poles, conductor and cables. Moving poles and lines to accommodate the widening or realignment of a road or development of other infrastructure are examples of this. Relocations may also occur for aesthetic reasons, such as where a customer requests undergrounding on lines that disrupt their views.

[79] The National Institute of Water and Atmospheric research (NIWA) has predicted an increase in frequency of severe weather events over the next 50 years.

5.12.1. Asset relocation process

Requests to relocate assets for roading and infrastructure development projects generally require significant planning, and coordination with other infrastructure providers. It is necessary for us to be directly involved in the relocation design process. Other requests mainly involve relocation of assets on private land and are usually less complex, allowing authorised contractors to develop a design-build proposal.

If the relocation involves assets that are in poor condition or defective, we may take the opportunity to upgrade and address defects, utilising planned road closures and reducing the need for planned outages. Where assets are replaced as part of a relocation – usually when in poor condition – expenditure is capitalised. Relocating assets from one location to another without increasing service potential is treated as operating expenditure.

In most circumstances we receive contributions from the third party requesting the relocation, reducing the amount of our investment in these projects. For roading and other infrastructure projects, the level of our investment is governed by legislation which often requires us to fund the materials portion of the project.[80] For other projects, our level of investment is governed by the moving works section of our publicly disclosed capital contributions policy. In general, customers other than roading authorities requesting relocation of existing assets are required to fund the full cost of the works, including the costs of providing or securing easements. An exception may be made when assets are in poor condition and due for replacement.[81]

5.12.2. Forecast Relocations

Our forecast relocations expenditure is our expected investment (net of contributions) during the period. This is difficult to forecast as work is externally-driven, often with short lead times. Capital requirements for relocations vary significantly from year to year – requirements in the past three years have been higher than average, linked to the intensity of subdivision development.

We estimate relocation expenditure based on historic average expenditure, adjusted for known projects that are expected to occur within the next few years. Two major projects have been accounted for in our forecast. These are NZTA roading projects to relocate assets at the Kawerau Fall bridge in Queenstown and to underground overhead circuits along SH6 to allow construction of additional traffic lanes. These are expected to be completed in 2019 and 2021, respectively.

Our forecast capital cost of relocations is higher over the period to 2021 as the above projects are completed, with expenditure after that time in line with the longer-term average.

80 Sections 32, 33 and 35 of the Electricity Act 1992 and Section 54 of the Government Roading Powers Act.

81 Capital contributions are designed to ensure that any uneconomic portion of the incremental cost of supply is paid by the customer requiring the work, and not transferred to existing customers through increased line charges.

6. NETWORK DEVELOPMENT

This chapter introduces our approach to developing our network. It provides a brief explanation of what we mean by network development, before focusing on the growth and security investments we plan to undertake during the AMP planning period. The chapter also discusses investments focussed on managing network reliability and investments we make to facilitate customer connections.

6.1. INTRODUCTION

We use the term network development to describe capital investments that increase the capacity, functionality, or size of our network. Network development includes three main types of investment:

- **Growth and security**: these are investments to ensure we can meet demand on our network while maintaining appropriate security of supply.
- **Reliability-driven**: these investments aim to minimise the impact of an event, such as by automatically reducing the number of customers impacted by it.[82]
- **Customer connections**: this is expenditure to facilitate the connection of new customers to our network.

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. We expect this to be a significant area of investment in our Central Otago network over the planning 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 loading on some of our assets is approaching maximum capability and we need to significantly increase our growth and security investments from historical levels.

The remainder of this chapter focuses primarily on our network development planning process for growth and security investments, and the key inputs to the process. It provides examples of important growth and security projects that we intend to undertake during the planning period. Our approach to developing a plan for reliability-driven investments is discussed in Section 6.6, while our approach to new customer connections is discussed in Section 6.7.

6.2. NETWORK DEVELOPMENT PLANNING

The objective of network development is to expand the network into new areas, or to increase the capacity or functionality of our network to meet the current and future needs of our customers in a cost-effective manner. This definition includes maintaining adequate security of supply, improving reliability, and maintaining power quality, as well as meeting demand.

82 The Commerce Commission defines reliability, safety and environment Capex as spend predominantly associated with improvement of reliability of service, maintaining or improving the safety of the network for consumers, employees and the public, meeting legislative requirements, or reducing the impact of the network on the environment.

Network development planning requires that we anticipate potential capacity shortfalls or breaches of our security criteria, under forecast demand conditions. We plan for efficient and timely investment in additional capacity and security before reliability is adversely affected.

We broadly classify our growth and security investments into the following types of project:

- **Major projects**: generally involve zone substations, subtransmission or GXP related works
- **Distribution reinforcement**: works to ensure adequacy of our distribution feeder assets
- **LV reinforcement**: works to ensure adequacy of our LV network.

Below we discuss these project types and provide an overview of our planned investments in each category over the planning period.

Reliability-driven and customer connection investments are also types of network development. These are discussed later in the chapter.

Major projects

Major projects typically involve zone substation, subtransmission or GXP-related work driven by network security considerations. Examples include growth or security-driven zone substation upgrades and the addition or upgrade of subtransmission lines driven by growth.

An important part of meeting growth and security needs is providing alternative capacity (redundancy) that can be used when a primary asset is out of service. This is particularly important for subtransmission and zone substation assets due to the size of the load served by them. We identify major projects by assessing the performance and capacity of our subtransmission network and zone substations in both a normal configuration (i.e. no elements out of service), and under various contingency scenarios as specified in our security of supply standard (refer to Section 6.3.2). The tools used for this analysis and the key inputs are described in Section 6.2.

We expect to carry out a significant number of major projects during the planning period. Examples are provided in Section 6.5.2, while a complete list of projects currently in our ten year plan is provided in Appendix D.

Distribution Reinforcements

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.[83]

We classify our distribution feeders into four categories based on the predominant type of load (or customer) served by that feeder. The load type provides a proxy for the expected economic impact of lost supply to that load (or customer). The reliability performance of a feeder is significantly influenced by network configuration. Security of supply standards are established for each feeder type (refer to

83 Occasionally the upgrade of a distribution transformer will occur as part of the above works but more generally this work is delivered as part of our customer connections work, which is described in section 6.7.

Table 6.3), and these are used in our planning process to determine distribution network configuration needs.

Providing alternative distribution feeder capacity (redundancy) for use in the event a primary asset is out of service varies across our network. For Dunedin and parts of urban Central Otago, the scale and high density of the network supports provision of interconnected distribution feeders at low cost. For the rural areas of Central Otago, distribution feeders are less often interconnected, as it is not cost effective in many situations. This is reflected in our growth and security planning approach where we assess the performance and capacity of our 11 kV feeders against the criteria in our security of supply standard.

Distribution growth and security planning typically results in the following types of projects:

- line upgrades and new sections of line (tie lines or new feeders)
- new cables, usually of larger capacity
- specific back-feed initiatives (increased capacity or new tie lines)
- feeder voltage support (i.e. regulators or capacitor banks)

Our distribution reinforcement forecast is split across three categories:

- **Identified**: reinforcement projects that are generally planned one to four years in advance
- **Non-identified**: forecast level of reinforcement projects typically beyond four years
- **Non-scheduled**: reinforcement projects carried out on a reactive basis as needed.

For identified projects we forecast the cost based on scoped works for the identified projects. The forecast cost for smaller works is based on historical trends. Total spend on distribution reinforcement of $1-2 million per annum is forecast for the planning period, although this will vary from year to year due to the lumpy nature of some works.

LV Reinforcement

Planning for LV reinforcement is a relatively reactive process, reflecting the lower value and higher volume of assets (compared to distribution level). The addition of new load is managed through our customer connection process.[84] We assess available capacity on a case-by-case basis and undertake reinforcement work if required. Historically, this process has largely captured the material changes in load. Occasionally, power quality issues (e.g. low voltages) have emerged as a result of unknown changes in load. Historically, we have addressed these changes reactively.

This reactive process works well in an environment where the underlying electricity usage behaviour is stable. It also works well where new distributed generation is connected to our network, as this requires a connection application outlining the type and quantity of generation, allowing us to develop a solution in advance. However, in an environment where customers materially change their electricity usage behaviour (e.g. emerging technologies including heat pumps displacing wood fires, electric vehicles, energy efficiency initiatives, retailer promotions, or battery storage), and there is no requirement to notify us, we will not be able to rely entirely on our connection application process to capture the changes in load.

[84] Note that LV reinforcement is concerned with the LV network impacts of new customer connections, rather than the actual connections. Investments for customer connections are discussed in section 6.7.

In the short term, with relatively low levels of customer behaviour change, we will manage the low voltage network capacity using improved high-level analysis and modelling tools that enable an annual review of the utilisation of all our low voltage feeders. We have limited capability in this area at present, and we will be resourcing this as part of improving our asset management capability. This analysis will enable us to identify those feeders with high levels of utilisation (through either load or distributed generation) for more detailed analysis, and to potentially install real-time monitoring equipment on them.

In the medium to long term, the customer uptake of emerging technologies may require the installation of widespread monitoring equipment. There is also an opportunity to better utilise customer metering data for planning analytics and/or real time monitoring. An example of customer behaviour change that would benefit from real-time monitoring is residential battery use.

We are mindful that monitoring and signalling of customer response to manage the impact of emerging technologies on our low voltage network will likely have cost implications, and that optimal timing for monitoring solutions may vary given the uncertainty associated with the extent and rate of uptake. We also need to consider the potential for obtaining information/data from smart metering and/or customer technologies to offset the need for network monitoring. In light of this, we intend to take a staged approach, moving from enhanced modelling to a targeted (as opposed to network-wide) rollout of monitoring and signalling/control devices.

At this stage, we do not have a programme to monitor emerging power quality trends on the network, such as the increasing harmonics associated with the high penetration of irrigation loads. We intend to develop a strategy to determine underlying trends in power quality, as this will enable us to identify issues so we can intervene proactively where needed. Our LV reinforcement forecast includes modest investment in some initial monitoring of our low voltage network and network power quality, in general.

At present the delineation between LV reinforcement and customer connections works is not precise. Focussing on clearly separating these will enable us to better understand the drivers for LV reinforcement and develop more innovative solutions to emerging LV network management issues. As a consequence, we expect that future AMP forecasts will see a shift of costs from customer connections to LV reinforcement, with a possible increase in overall investment to accommodate the uptake of emerging technologies such as electric vehicles and photovoltaics.

We forecast LV reinforcement Capex of approximately $100k per annum using a trend approach based on historical works.

6.2.1. Planning Process

In this section we describe our approach to planning capital network development investments. This explains how we ensure that our investments prudently support our asset management objectives.

Our decision-making approach for approving network development Capex is at an early stage of development. It uses a defined challenge and approval process which includes need identification and options analysis. This ensures that appropriate governance is applied and that challenges are posed at appropriate stages as investment plans are developed and refined.

The degree to which we use this process is commensurate with the size of the works. For example, small routine feeder projects may be approved as a large bundled work programme.

The main stages of the lifecycle approach are the same as for the renewal process, discussed in Chapter 5, the main difference being that network development projects are more often customised to the need. The main stages up until delivery and commissioning[85] are:

- **Needs identification**: we undertake Capex investments in response to a number of investment drivers or triggers, including network demand growth
- **Options analysis**: following identification of a need we consider potential solutions to address the underlying driver
- **Preferred solution**: we select a preferred solution from the potential options.

Below we provide further detail on these processes and how they are employed for growth and security investments.

Identifying Needs

We identify network needs through systematic analysis which signals that certain criteria have breached accepted norms or standards.[86] This prompts us to define the need and determine the date at which it occurs.

Triggers for growth and security investments vary by voltage level, as follows:

- **GXPs/transmission spurs**: triggered by security criteria – effectively N-1 – being exceeded
- **Subtransmission and zone substation**: triggered by security criteria which are effectively a qualified, or switched, N-1 being exceeded
- **Distribution feeders**: triggered by guidelines or planning parameters related to voltage profile, thermal capacity of any given section of feeder, or security criteria being exceeded
- **LV feeders**: our process for determining investment needs has historically been based on new connection information. Our plans to adopt a more data-driven approach are described above.

Investment drivers are discussed in more detail in Section 6.3.

For growth and security planning, we rank identified needs according to the risk exposed by the associated network constraint. This assists with the ranking and timing of related investments.

Assessing Options

We carry out options analysis for all identified needs, with the level of complexity of the analysis in proportion to the level of risk associated with the identified constraint and the likely cost of a project to meet the need.

We have developed a systematic and objective process to assess options to achieve appropriate levels of capacity or reliability. Options include new assets, enhancements to existing assets, operational approaches, and non-network options. Options must be feasible and able to be safely and reliably implemented in sufficient time to meet the need.

For major projects we use a lifecycle-based approach to options analysis, which involves consideration of all appropriate cost elements over the expected lifetime of the asset, including not only the initial

85 As discussed in chapter 5, once assets are commissioned they pass into the operate and maintain stage.

86 We also review the full list of planned renewal projects, with a view to determining whether future growth needs should be addressed as part of a renewal.

investment, maintenance costs and disposal costs but other costs such as losses or reliability where these are expected to vary between options. The analysis identifies the most cost-efficient, long-term solution and its estimated cost. For reinforcement projects there are generally fewer alternatives – in some cases only one option in addition to a "do-nothing" option – and analysis is less detailed.

We plan to enhance our decision making processes to include specific requirements, such as risk assessments and forecasting methodologies, as part of our Asset Management Development Plan (AMDP) discussed in Chapter 7. We also intend to develop standard tools and guidelines for undertaking options analysis so that the assumptions and approach remain consistent, traceable, and documented. The tool will also provide built-in rates and help with cost estimation. These rates will be aligned to future business-wide cost estimation systems. The options analysis process is discussed in more detail in section 6.4.

Selecting a Preferred Solution

We take a number of factors into consideration when selecting a preferred solution. These factors include the extent to which the option addresses the need, the risk associated with each option, and the costs and benefits of the solution, which may include some that we are unable to quantify.

Network development projects need to fit within the context of our wider asset management activities (e.g. renewal plans), so 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, although this needs to be assessed in each case and may require careful management.

6.2.2. Key Planning Assumptions and Inputs

The key inputs informing our network development planning 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, and other factors impacting our equipment ratings
- voltage requirements and other regulated limits.

Key assumptions informing our planning are:

- 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 reflect future levels of demand management
- industry rules will remain broadly stable and will not lead to step changes in security requirements or levels of distributed generation.

6.2.3. Network Modelling

We use several tools for modelling load flows and contingency analysis. A DigSilent load flow model is used for subtransmission modelling and contingency analysis. We are in the process of developing distribution feeder models for DigSilent, which we expect to complete over the following year. In the meantime, we use simplified voltage drop models for our distribution networks.

We plan to enhance our decision-making processes to include specific requirements such as risk assessments and probabilistic modelling as part of our AMDP, as discussed in Chapter 7.

6.3. INVESTMENT DRIVERS

The need for network development investments is driven by a number of factors including:

- **System demand:** the peak demands for power and energy at GXP, zone substation and 11 kV distribution feeder levels compared to the capability of our networks (section 6.3.1)
- **Security of supply**: our ability to meet defined supply security standards (section 6.3.2)
- **Power quality**: ability to meet power quality regulatory and industry standards (section 6.3.3).

The following sections provide more detailed discussion on these key drivers.

6.3.1. System Demand

As described in Chapter 3, electricity demand varies over time, on a daily and seasonal basis, as well as longer term as a result of changes in population, economic activity, and customer behaviour. It can vary significantly from one part of the network to another.

Capacity constraints caused by growth in peak demand are a key driver of investment needs.[87] We are seeing ongoing demand growth leading to capacity constraints in some areas of our Central Otago network.

Demand Forecasting

To effectively plan for growth, we need to estimate the size and location of future loads. Our focus is on peak demand (rather than energy) as this primarily drives the need for network development.

The long lead time for major projects to reinforce or upgrade our larger capacity assets, such as subtransmission circuits, requires us to foresee increased demand some years before it eventuates. However, we must equally consider factors that may depress growth to avoid investing too much or too early. We forecast demand on an annual basis, looking ten or more years into the future.

While many factors affect demand, the two main drivers are population growth and economic activity. To an extent, these two factors are related. Demand is also impacted – albeit to a much lesser degree – by changes in behaviour and usage. Improved energy efficiency is one example of this. Looking forward, uptake of new technologies (for example, photovoltaic generation, battery storage, electric vehicles) is likely to be the major cause.

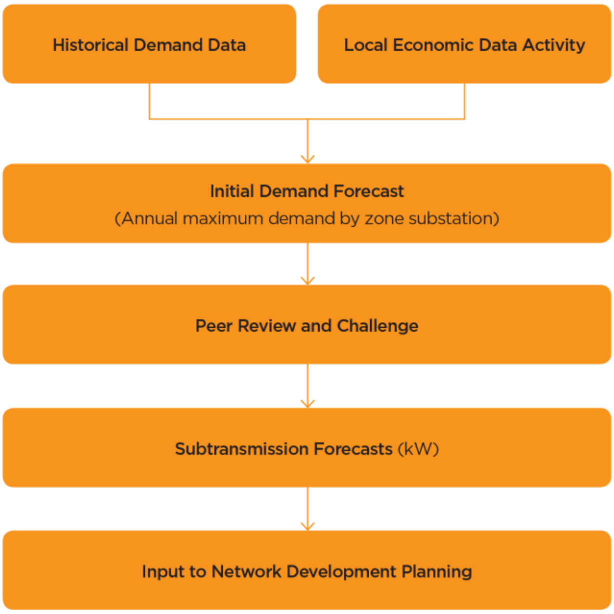
[87] Note that capacity constraints do not reflect total instantaneous capacity, as they take security of supply requirements into consideration.

For growth and security planning, we initially forecast peak demand at the zone substation level. We extrapolate historical demand trends, and adjust the results to reflect expected variations from the trend, for example, changes to irrigation technology (impacting energy intensity) or significant tourism or residential developments. These trends may be represented by step changes (as in the case of a new load), or an adjustment to the trend.

We consider future load on HV feeders, if needed, by applying the relevant zone substation growth rate to the previous year's peak demand at each feeder, and adjusting for any known step changes (such as new subdivisions).[88] However, we plan to implement a system of triggers for individual feeder analysis to ensure potential issues are not missed. For example, feeder analysis would be triggered when peak load reaches a specified percentage of nominal feeder capacity or N-1 capacity. This will require additional data records to be retained as part of our AMDP, as discussed in Chapter 7.

Demand forecasting is a key input to determining investment needs. Changes in the forecast from one year to the next may result in planned projects being brought forward or deferred. Figure 6.1 shows the key elements of our current demand forecasting approach.

Figure 6.1: Demand forecasting approach



Going forward, we plan to replace our trend-based forecasting models with bottom-up models that reflect the key underlying drivers of growth – population and economic activity. This will require local information on population changes, planned greenfield developments and construction activity. We will also undertake studies on key loads, such as irrigation, to better understand the magnitude and timing of potential developments.

We will continue to study broader industry-wide trends such as uptake of distributed generation, electric vehicles and batteries, and the use of smart control devices in the home. What we learn from

88 Peak demand in the previous year is reviewed and adjusted for abnormal factors such as load transfers or false values, to determined base year peak demands, to which zone substation growth rates are applied. Adjustments may be made, as to zone substation forecasts, for known or reasonable expected local impacts.

such studies will be incorporated in scenario modelling in future to improve our understanding of the potential impact of disruptive technologies on our business.

Network Level Forecasts

The following figures show our forecasts of annual energy and peak demand at the network level. The first two figures show aggregate energy (GWh) and peak demand (MW) forecasts for the combined networks. These are followed by individual forecasts for each of the Central Otago and Dunedin networks.

Figure 6.2: Total System Energy Forecast (GWh)

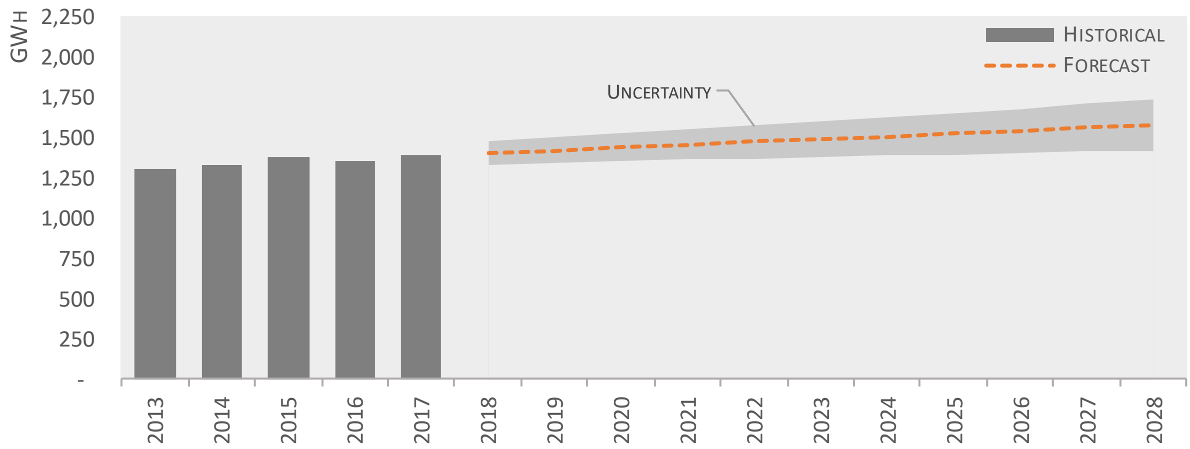
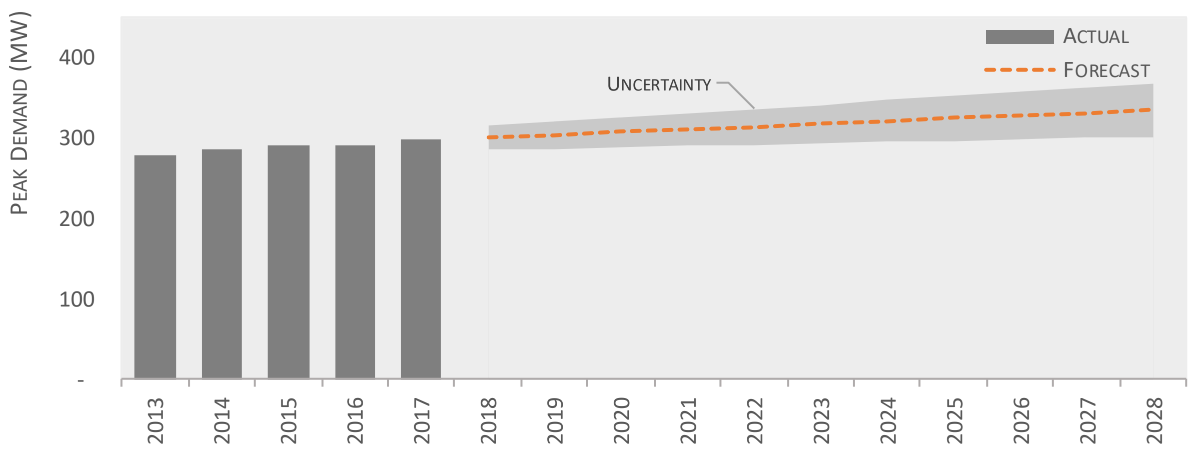


Figure 6.3: Total System Peak Demand Forecast (MW)



Aggregate energy demand has been relatively flat over the past decade, while peak demand shows a slow increase over the same period. This reflects the flat to declining load on our larger (Dunedin) network, coupled with fast growth in the smaller of our networks (Central Otago), as shown in the following figures.

The uncertainty band around the forecast increases further out into the future. This reflects that we can be fairly certain that growth will continue in the near term, but less certain about longer term growth in the Central Otago region.

Figure 6.4: Central Otago Energy Forecast (GWh)

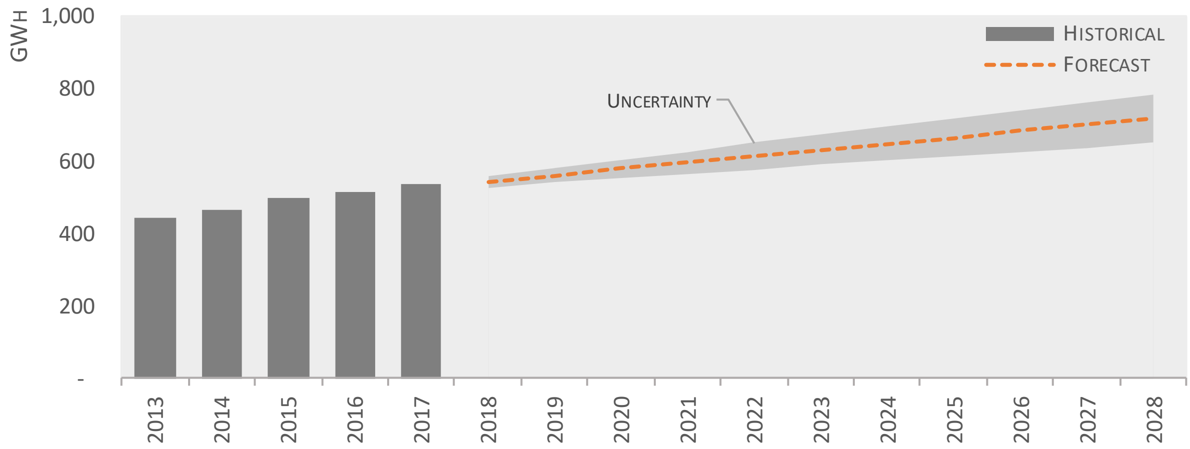
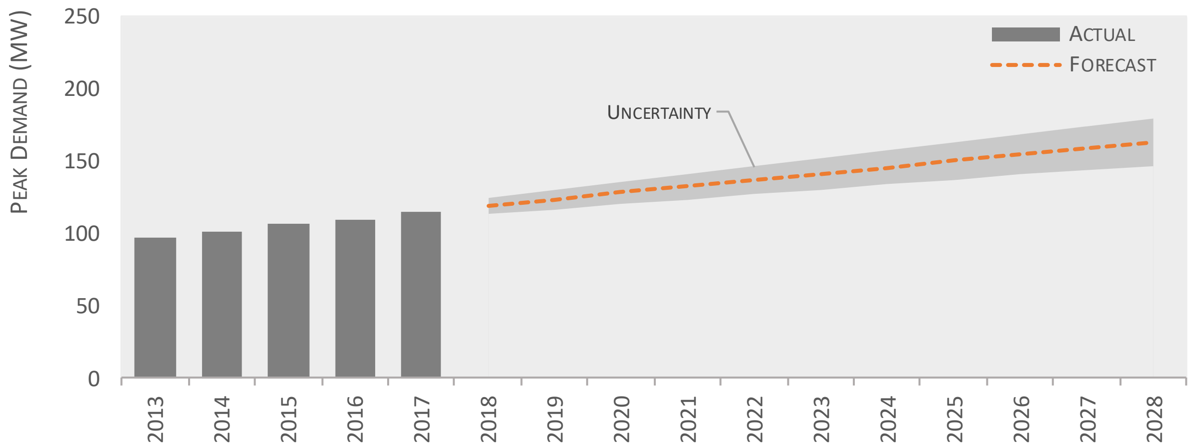


Figure 6.5: Central Otago Peak Demand Forecast (MW)



We have seen relatively fast growth in both energy (averaging 2.3% per annum) and peak demand (2.4% per annum) on our Central Otago network over the past five years. This high level of growth reflects the significant increase in residential load in the area, together with growth of irrigation and tourism loads. We expect continued growth at a rate of close to 3% per annum over next five years, reflecting ongoing growth in these sectors.

Figure 6.6: Dunedin Energy Forecast (GWh)

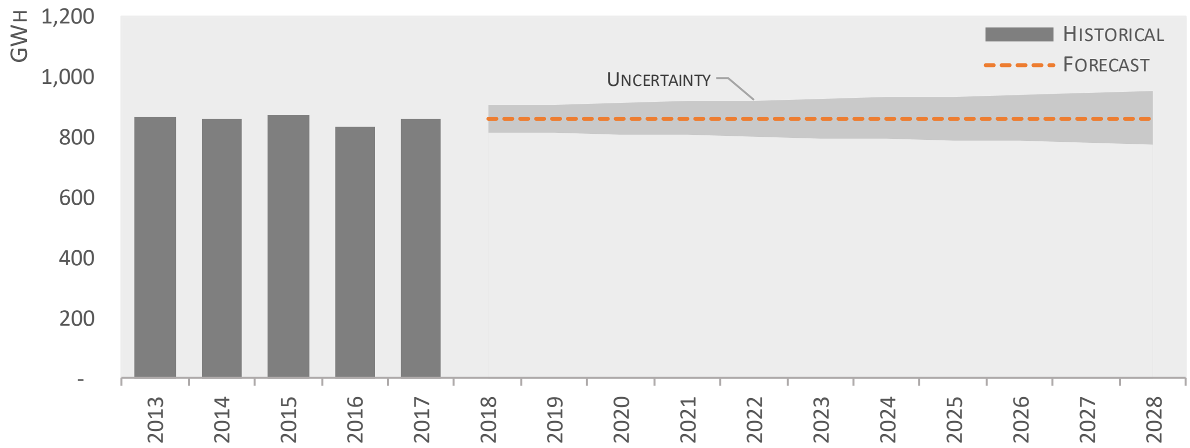
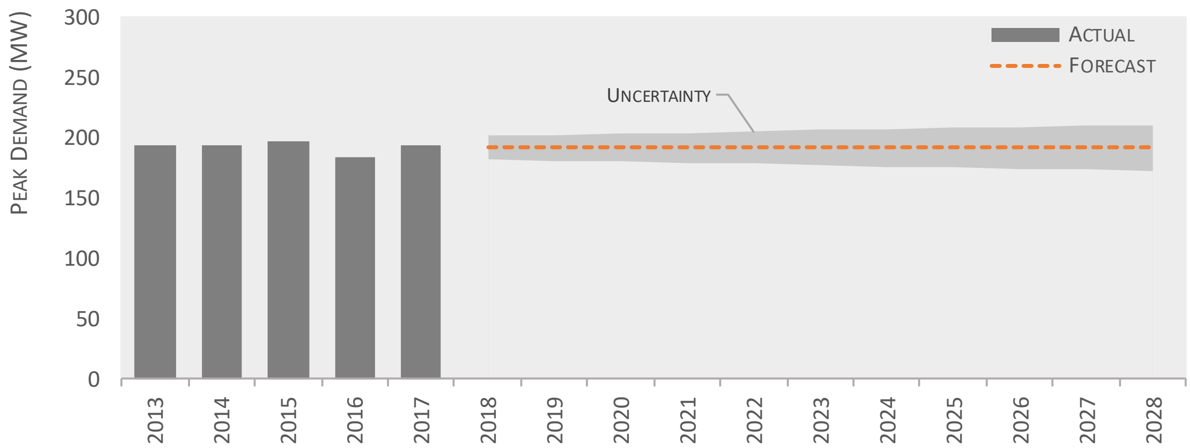


Figure 6.7: Dunedin Peak Demand Forecast (MW)

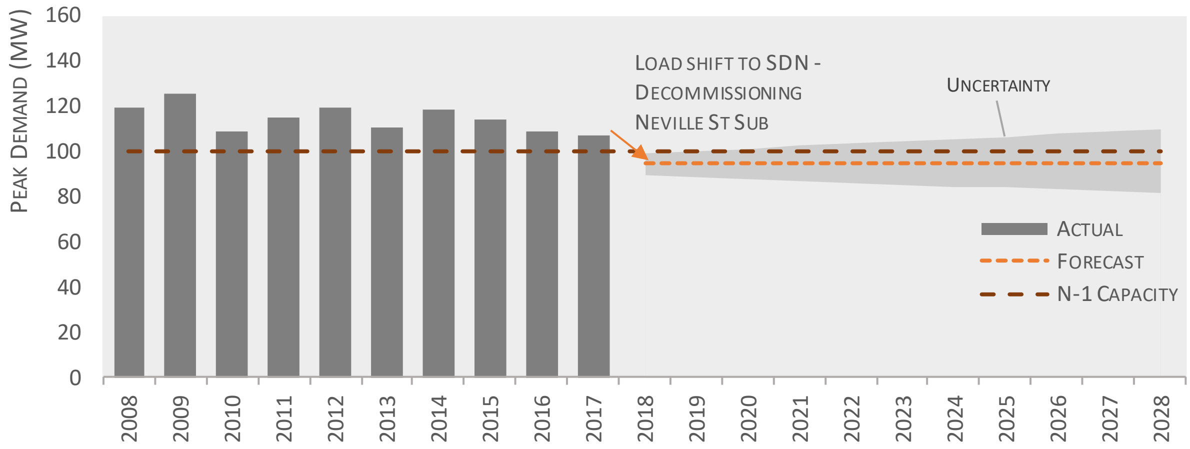


In contrast, energy demand on the Dunedin network has fallen by approximately 6.5% over the past decade. Peak demand has remained steady over the same period. We do not expect any growth in either peak or energy demand on our Dunedin network over the planning period.

Forecast Demand – GXP level

The charts in this section show historical and forecast peak demand for the two Dunedin GXPs – Halfway Bush and South Dunedin and the three Central Otago GXPs – Frankton, Cromwell and Clyde.

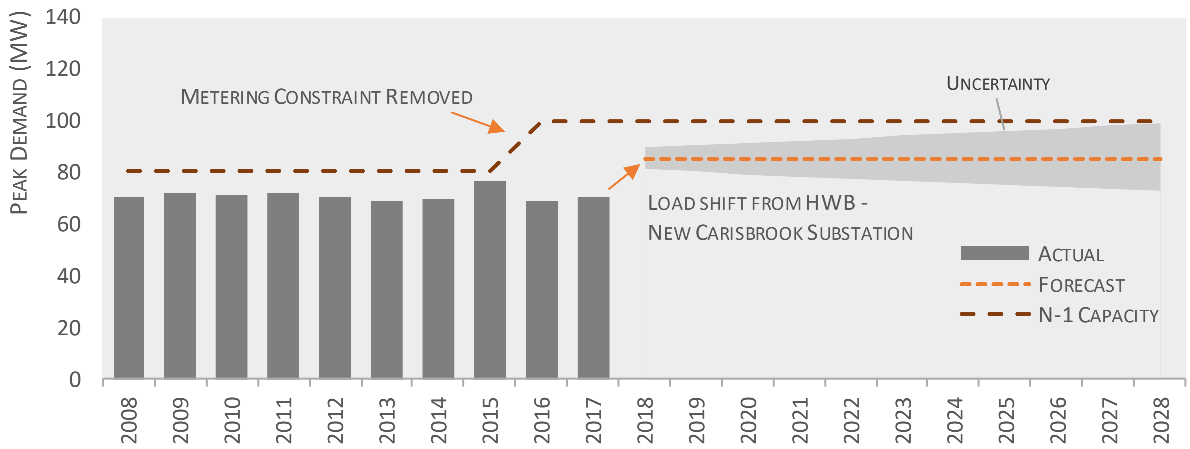
Figure 6.8: Halfway Bush GXP Peak Demand Forecast (MW)



Peak load on the Halfway Bush GXP is offset by generation from Waipori, which is embedded within our network. Figure 6.8 shows net peak demand at the GXP. The variability is due to the varying output of the embedded generation, while underlying load has been stable. We expect this trend to continue as illustrated by the flat forecast demand shown above.

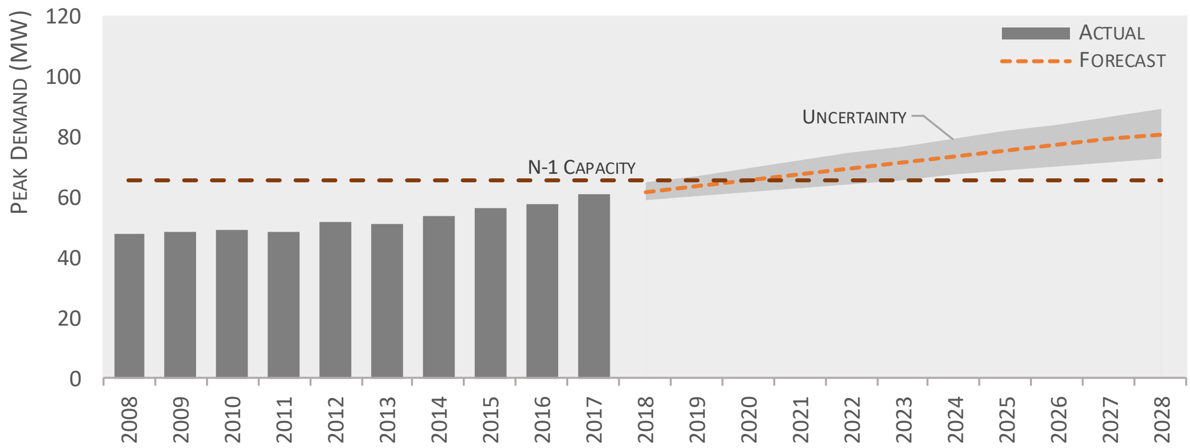
Peak offtake at Halfway Bush has historically exceeded the N-1 post-contingency rating of the GXP. Decommissioning the Neville Street substation (and replacement with the new Carisbrook substation) in 2018/19, will shift 14 MW of load from this GXP to South Dunedin. However, we expect that even after this shift, peak demand will be close to N-1 capacity; we will continue to monitor this.

Figure 6.9: South Dunedin GXP Peak Demand Forecast (MW)



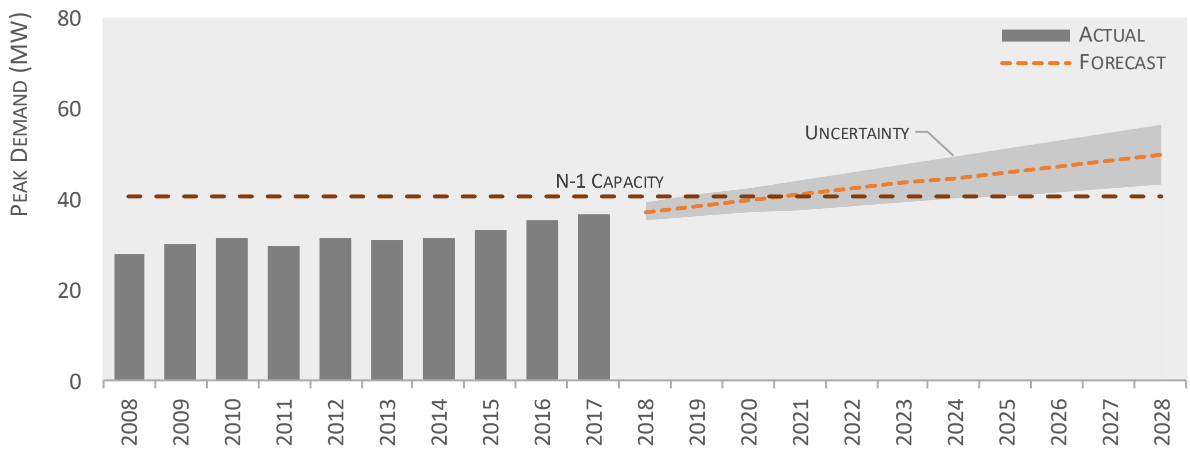
South Dunedin GXP has seen relatively stable peak demand over the past decade, showing no growth or a slight decline. The forecast shown in Figure 6.9 incorporates the planned load shift from Halfway Bush to the South Dunedin GXP. We expect future peak demand to remain below the current N-1 capacity.

Figure 6.10: Frankton GXP Peak Demand Forecast (MW)



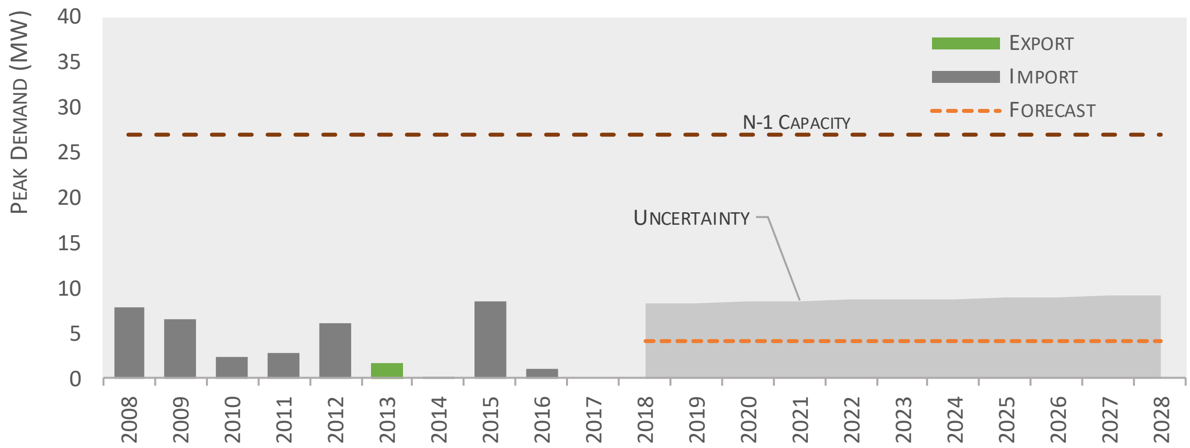
Frankton GXP has shown steady growth over the past five years, in line with commercial and residential growth in the wider Queenstown area. We expect load at Frankton GXP to exceed the N-1 post-contingency capacity by 2020. Transpower is investigating a number of tactical and relatively low cost upgrades to the Frankton GXP N-1 capacity that will meet expected growth over the next ten years. Collectively with Transpower, we are investigating longer term options for the region to manage the possibility of higher than expected growth and to ensure adequate lead time for projects that may require resource consents.

Figure 6.11: Cromwell GXP Peak Demand Forecast (MW)



Cromwell GXP has seen strong growth in recent years as a consequence of development in both Cromwell and Wanaka. We expect that the GXP's N-1 capacity rating will be exceeded by 2021. Our financial forecasts make provision for a third autotransformer at Cromwell, to bolster capacity to Wanaka. However, we recognise that this will not resolve the GXP constraint and we are investigating alternative upgrade options including taking supply from Transpower at 110 kV to reduce load on the 33 kV GXP. The rate of growth is partly dependent on the timing and staging of expansions at the Cardrona and Treble Cone ski fields.

Figure 6.12: Clyde GXP Peak Demand Forecast (MW)



Due to high levels of embedded generation behind the Clyde GXP, the transformers there are lightly loaded most of the time. In the unlikely event that multiple sites of embedded generation are offline, GXP peak demand could reach 20 MW. This is still below the N-1 post-contingency capacity limit. There is potential for further irrigation growth but we do not expect either summer or winter peak demand to exceed the capacity of this GXP over the next ten years.

Forecast Demand – zone substation level

Tables 6.1 and 6.2 set out forecast peak demand by zone substation.

Table 6.1: Zone substation demand – N-1 Transformer Sites (see Table 6.3 for Security Class Definitions)

		Firm	Historical								Forecast									
Zone Substation	Security Class	Capacity MVA	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Alexandra	Z2	15	11.6	10.9	11.7	10.6	10.7	11.7	12.0	11.1	11.7	11.8	11.9	12.0	12.2	12.3	12.4	12.5	12.7	12.8
Andersons Bay	Z1	18	15.3	16.0	15.4	16.2	14.5	15.6	15.0	15.0	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Arrowtown[1]	Z2	6	7.9	7.6	8.3	8.3	7.9	8.8	8.5	8.5	9.1	9.5	9.8	10.2	10.6	11	11.4	11.7	12.1	12.5
Commonage	Z2	17	9.8	9.8	11.4	11.7	10.2	10.6	12.0	12.2	12.2	12.5	12.8	13.1	13.4	13.6	13.9	14.2	14.5	14.8
Corstorphine[11]	Z2	23/24	13.2	13.8	13.1	13.0	12.5	14.0	12.8	12.8	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
Cromwell[2]	Z2	7.5	10.0	9.4	9.7	10.3	10.7	10.6	11.0	11.2	11.4	11.6	11.8	12.1	12.3	12.5	12.7	12.9	13.2	13.4
East Taieri	Z1	24	15.8	16.2	16.5	16.7	15.9	17.0	16.0	16.0	16.3	16.3	16.3	16.3	16.3	16.3	16.4	16.4	16.4	16.4
Frankton[3]	Z1	15	12.1	10.5	13.3	13.3	13.0	14.3	14.0	14.6	15.0	15.4	15.8	16.2	16.6	17.0	17.4	17.8	18.2	18.6
Fernhill	Z2	10	5.8	5.8	5.9	5.9	6.3	6.3	6.4	6.7	6.8	6.9	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1
Green Island	Z2	18	13.4	14.0	13.7	13.7	13.3	14.0	13.3	13.3	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Halfway Bush[4]	Z2	18/24	14.6	14.8	14.6	14.5	14.1	15.0	14.5	14.5	14.6	14.6	14.7	14.7	14.7	14.7	14.8	14.8	14.8	14.8
Kaikorai Valley[5]	Z2	23/24	9.2	9.3	10.7	10.7	10.6	10.8	10.2	10.2	10.7	10.7	10.8	10.9	10.9	11.0	11.1	11.2	11.2	11.3
Mosgiel	Z2	12	7.6	7.8	8.0	8.3	7.1	6.9	6.9	6.9	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Neville St[6]	Z2	18	13.4	13.6	13.6	12.9	13.1	13.1	11.6	11.6	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
North City[7]	Z1	28	19.0	20.0	18.9	19.6	19.1	18.8	18.2	18.2	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9
North East Valley	Z2	18	11.2	11.8	11.0	11.3	11.1	11.4	10.8	10.8	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1
Port Chalmers	Z2	10	7.5	7.5	7.5	7.1	7.0	7.3	6.5	6.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Queenstown	Z2	20	14.7	15.1	13.5	13.3	13.6	14.0	14.2	14.0	15.2	15.5	15.7	15.9	16.1	16.3	16.5	16.7	16.9	17.1
Smith St	Z1	18	15.8	16.9	16.7	16.1	15.5	15.2	14.0	14.0	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
South City	Z1	18	15.0	15.2	15.0	14.8	14.9	16.1	15.3	15.3	15.6	15.7	15.8	15.9	16.0	16.1	16.2	16.3	16.4	16.5
St Kilda[8]	Z1	23/24	15.3	15.5	15.3	15.6	15.5	16.0	14.8	14.8	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Wanaka[9]	Z1	24	20.3	17.6	19.2	18.8	18.8	20.3	19.4	19.8	20.5	21.2	21.9	22.6	23.2	23.9	24.6	25.3	26	26.7
Ward St[10]	Z2	23/24	11.9	14.3	14.2	12.7	12.8	12.8	10.7	10.7	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Willowbank	Z2	18	12.2	13.2	12.1	12.5	12.3	12.5	12.6	12.6	12.6	12.6	12.7	12.7	12.7	12.7	12.8	12.8	12.8	12.9

Notes:

(1) A third transformer will be added to the Arrowtown site in RY19 to raise the firm capacity to 12 MVA.
A new 33 kV feeder from Frankton is proposed to resolve a constraint on the Arrowtown 33 kV supply lines.
(2) The Cromwell transformers will be upgraded to 24 MVA in RY20.
(3) We will monitor growth at Frankton and consider an upgrade to the smaller 15 MVA transformer at this site, but intend to manage growth during the AMP period by transfers to Commonage zone substation.
(4) The capacity at Halfway Bush is currently constrained to 18 MVA by the 6.6 kV switchboard which has a planned replacement in RY22.
(5) The capacity at Kaikorai Valley is slightly constrained to 23 MVA by the 6.6 kV switchboard.
(6) To be replaced by Carisbrook, which will be 24 MVA.
(7) The North City forecast excludes the new hospital connection. Similarly the cost to relocate North City zone substation (if required) has not been included our financial forecasts
(8) The capacity at St Kilda is slightly constrained to 23 MVA by the 6.6 kV switchboard.
(9) It is proposed to relieve the Wanaka constraint by the installation of transformer capacity at Riverbank in RY25.
(10) The capacity at Ward St is slightly constrained to 23 MVA by the 6.6 kV switchboard.
(11) The capacity at Corstorphine is slightly constrained to 23 MVA by the switchboard.

Table 6.2: Zone substation demand – N Transformer Sites (see Table 6.3 for Security Class Definitions)

Zone Substation	Security Class	Capacity MVA	Historical 2010	2011	2012	2013	2014	2015	2016	2017	Forecast 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Berwick	Z3	3.6	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6
Cardrona[1]	Z3	6.0	0.0	1.9	3.1	2.8	3.3	2.9	4.0	4.1	5.0	5.0	5.0	5.0	9.0	9.0	9.0	9.0	9.0	9.0
Clyde/Earnscleugh[2]	Z3	4.8	4.1	3.8	3.8	4.3	4.2	4.2	3.2	3.1	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
Coronet Peak[3]	NA	6.0	4.6	4.6	4.6	4.9	5.4	4.9	6.0	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Dalefield[4]	Z3	3.6	2.3	2.3	2.7	2.7	2.8	3.1	3.0	2.4	2.9	3.0	3.1	3.3	3.4	3.6	3.7	3.8	4.0	4.1
Earnscleugh[5]	Z3	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ettrick	Z3	3.6	2.0	1.7	2.0	2.5	1.7	2.2	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Lauder Flat	Z3	3.6								0.7	0.8	1.3	1.6	1.8	2.1	2.4	2.6	2.6	2.8	3.0
Lindis Crossing[6]	Z3	7.5						4.5	6.0	5.9	6.0	6.0	6.1	6.2	6.3	6.4	7.1	7.9	8.6	10.0
Camp Hill[7]	Z2	6.5	2.3	2.3	2.6	3.3	4.0	4.0	5.2	5.3	5.3	5.6	5.9	6.2	6.5	6.8	7.1	7.4	7.7	8.0
Omakau[8]	Z3	3.6	2.1	2.0	1.9	2.4	2.8	3.1	3.4	2.8	2.8	2.8	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2
Outram	Z2	3.6	2.9	3.0	2.9	3.0	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Queensberry	Z3	4.0	2.4	2.3	2.5	4.5	6.0	3.0	2.3	2.8	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9	3.9
Remarkables[9]	NA	3.6	0.8	1.0	1.2	1.2	1.9	2.3	2.7	2.4	2.5	3.5	6.0	6.6	7.1	7.7	8.3	8.9	9.4	10.0
Roxburgh	Z2	6.0	2.8	2.3	2.3	1.1	1.8	1.8	2.3	1.8	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0

Notes:

(1) Load growth is subject to Cardrona ski field expansion going ahead. This AMP makes no provision for an upgrade at Cardrona at this stage.
(2) We have provision in this AMP to upgrade Clyde Earnscleugh but further investigation is required to determine the chosen solution.
(3) Load growth is subject to Coronet Peak expansion. This AMP makes no provision for an upgrade at this stage.
(4) It is proposed to upgrade Dalefield substation in RY26 with a solution taking account of Coronet Peak growth
(5) Earnscleugh zone substation is on hot standby as a back-up to Clyde Earnscleugh
(6) We propose to install a second transformer at Lindis Crossing in RY25.
(7) Further irrigation load growth at Camp Hill is uncertain. At this stage, no upgrade project has been included in our plans for the AMP period.
(8) Subject to further irrigation growth, it is proposed to upgrade and shift Omakau substation in RY25.
(9) A capacity upgrade at Remarkables is subject to Aurora Energy being the preferred supplier to the Remarkables ski field. At this stage we have made no allowance to upgrade this zone substation.

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Assessing Asset Capability

To determine investment needs arising from demand growth, we assess the capability of our assets to meet forecast demand. This approach relies on asset ratings.

Our asset ratings are based on the manufacturer (nominal) rating for each asset. However, actual safe capacity can vary in real time, depending on environmental conditions, such as temperature and wind speed. We further adjust the ratings of some assets to reflect such factors:

- **Zone substation transformers**: we assign a maximum continuous rating and also a four-hour rating which applies to post contingent load transfer in an N-1 context. Ratings may be amended from the standard to reflect local temperature extremes, or the shape of the load profile. Where the zone substation supplies irrigation loads, a cyclic or seasonal rating may be applied
- **Overhead lines**: short term ratings (e.g. four-hour rating) are not appropriate for overhead lines because of their limited thermal capacity. We use nominal continuous winter/summer ratings to systematically identify potential future overloads. We use summer ratings to reflect the actual maximum temperature when known
- **Underground cables**: We use standard manufacturer-based ratings for underground cables. Local conditions are taken into account. Generally ratings are determined per zone substation.

Ideally we would utilise statistical methods to assess the capability of assets to supply load. We do not currently take this approach, but are considering whether it would add value to our planning process.

6.3.2. Security of Supply

Security of supply is the ability of a network to meet the demand for electricity when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform and/or the quicker it can recover from a fault.

Managing system security is a key driver of growth and security investments. We establish appropriate security of supply criteria and apply these in our network modelling to identify investment needs.

Security criteria establish a required level of network redundancy. The degree of redundancy determines the ability of the network to maintain supply following the failure of an asset component. We specify our security criteria to support our performance objectives (Chapter 4) and the reliability performance sought by our customers and stakeholders. Security criteria generally drive the larger investments related to the subtransmission system and zone substations, which directly impact reliability experienced by large numbers of customers.

Security standards are normally defined in terms of N-x, where x is the number of coincident outages that can occur during high demand times without extended loss of supply to customers. At the levels of load encountered at most of our zone substations, N-1 is the optimal consideration (i.e. an outage on the single largest circuit or transformer can occur without resulting in supply interruption).

Our security of supply criteria (for GXPs, subtransmission and distribution networks) is set out below. This is an updated version that better reflects our view of the level of security of supply that customers seek. We welcome feedback on our new security of supply criteria.

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Table 6.3: Security of Supply Criteria

Class	Description	Load (MW)	Cable, Line or Transformer Fault	Double Cable, Line, or Transformer Fault	Bus or switchgear fault
GXPs					
CBD/Urban	GXPs supplying predominantly metropolitan areas, CBDs and commercial or industrial customers	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Rural/Semi-Rural	GXPs supplying predominantly rural and semi-rural areas	15-60	No interruption	Restore within 4 hours	No interruption for 50% and restore remainder within 4 hours
66 kV and 33 kV Subtransmission Networks					
Category Z1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	15 - 24	No interruption	Restore within 2 hours	No interruption for 50% and restore remainder within 2 hours
Category Z2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-15	Restore within 2 hours (may include use of the mobile substation)	Restore 75% within 2 hours and remainder in repair time	Restore within 2 hours
Category Z3	Predominantly rural and semi-rural areas	0-15	Restore within 4 hours (may include use of mobile substation)	Restore in repair time	Restore in repair time
6.6 kV and 11 kV Network					
Category F1	Predominantly metropolitan areas, CBDs and commercial or industrial customers	1-4	Restore all but 1 MVA within 2 hours, remainder in repair time[1]	Restore in repair time	Restore all but 1 MVA within 2 hours, remainder in 4 hours (using a generator)
Category F2	Predominantly metropolitan areas, CBDs and commercial or industrial customers	0-1	Restore in repair time[1]	Restore in repair time[1]	Restore in repair time[1]
Category F3	Predominantly rural and semi-rural areas	1-4	Restore all but 1 MVA within 4 hours, remainder in repair time[1]	Restore in repair time[1]	Restore all but 1 MVA within 4 hours, remainder in repair time[1]
Category F4	Predominantly rural and semi-rural areas	0-1	Restore in repair time[1]	Restore in repair time[1]	Restore in repair time[1]

Note 1: Generators to be used where feasible to enable restoration of power before the fault is repaired.

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Zone substation security levels can also be qualified by the time allowed to restore supply by network reconfiguration after an asset fails. Security levels for some security classes are qualified by the allowable switching time before all load can be restored.

Feeder classifications provide information on the type of loads supplied by each zone substation, which informs the zone substation's security classification. Our security standards also consider the size of load at risk. Higher levels of redundancy or back-feed capacity are required where more customers could be affected by an outage.

Effective tailoring of security standards for individual customers, especially in the mass-market, or at lower voltage levels is impractical. Our security criteria therefore are defined at HV feeder level and above only.

It is important to distinguish between reliability of supply – the actual performance of the network in terms of the amount and duration of interruptions – and security of supply – the innate ability of the network to meet the customer demand for energy delivery without interruption. When planning for load growth, we attempt to optimise the level of security and fault tolerance acceptable to our customers. This necessitates a balance between infrastructure investment and operational cost. Infrastructure investment is driven by security of supply requirements, while the reliability of supply actually achieved depends on a combination of security-of-supply and operational performance.

Network Gap Analysis

Our deterministic (N-x) security standard is used to identify areas on the network that may require investment to meet customer expectations. Combined with our load forecasts presented earlier in this chapter, we are able to forecast areas where a capacity or security of supply shortfall will emerge in the future. These network constraints are called network gaps.

The network development projects identified in this AMP address our critical network gaps. We will undertake further network gap analysis, including updates to our contingency plans, for all valid subtransmission contingencies. Testing the outcomes of our contingency analysis against our revised security of supply criteria will further inform our network development plans and also the suitability of the changes we have made to our security criteria.

Future updates to our AMP will report the results of our network gap analysis.

6.3.3. Power Quality

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.

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.

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

Voltage Magnitude

Regulations require voltage to be maintained between ±6% at the point of supply except for momentary fluctuations.

Harmonics - distortion and interference

Harmonic voltages and currents in an electric power system are typically a result of non-linear electric loads. Non-linear loads such as Variable Speed Drives (VSDs), Switch Mode Power Supplies (SMPSs), and electronic ballasts for fluorescent lamps and welders inject harmonic currents into the network. These harmonic currents couple with the system impedances creating voltage distortion at various points on the network. This can cause malfunction or complete failure of equipment such as computers, digital clocks, transformers, motors, cables, capacitors, and electronic controls which are connected at the same point.

The limits in Table 6.3 are used to gauge harmonic voltage distortion lasting longer than one hour. For shorter periods, during start-ups or unusual conditions, these limits may be exceeded by 50%.

Table 6.4: Maximum voltage distortion limits in % of Nominal fundamental frequency voltage

Individual Voltage Distortion (%)	Total Voltage Distortion (%)
3.0	5.0

6.4. OPTIONS ANALYSIS

Following need identification, potential solutions are identified and considered. The number and type of options (or solutions) varies depending on the type, value and complexity of the investment. We have a systematic, objective and documented process to identify network investment needs and to identify and assess options to address them. To achieve its objectives, this process needs to be applied more rigorously, and we are working to better embed it in our planning processes over the next year.

6.4.1. Types of Options

In the case of overhead lines, upgrade options may include thermal re-tensioning, reconductoring, or the installation of new lines or circuits. For all other investment needs, maintenance and development options are also explicitly considered. Typically options include:

- network reconfiguration
- network automation
- capacity upgrades
- additional assets
- non-network investments, such as demand management.

6.4.2. Options Analysis Process

Our options analysis process involves considering all technically feasible options and determining which performs best in terms of safety, whole-of-life cost and reliability outcomes. Cost analysis for growth and security projects tends to be dominated by two components – the upfront capital cost, and to a lesser extent, the impact of the investment option on reliability. Reliability reflects the cost of unserved energy to customers in the event that supply cannot be maintained.

We generally select the option with the lowest whole-of-life cost by determining the net present value (NPV) of the costs associated with a project. The use of NPV enables us to compare options with different development timeframes, such as where there is an option to stage construction over several years.

Non-monetised factors may be taken into consideration when selecting a preferred solution, for example, the future flexibility inherent in one option over another (option value), environmental impact, and community feedback.

Our process, following identification of a need, involves the following steps:

- preparing a project development report setting out the need and identified options (including non-network options), and providing preliminary cost and risk analysis
- a lifecycle cost analysis for all feasible options
- a development of scope document, setting out our need, options considered, assessment results, and proposed solution.

Currently, scope documents are only prepared one year ahead, i.e. currently for projects in the first year of this AMP. We plan to expand this process, using options analysis commensurate with project size, to cover all major projects included in the AMP. We are also building in a thorough assessment of the risks associated with the various options considered, including the do-nothing option.

6.4.3. Non-network Solutions

When the network becomes constrained, investing in new infrastructure may not be the best option to relieve the constraint. Other alternatives include:

- demand side management, including embedded generation
- energy storage solutions
- tariffs to provide incentives for the use of DSM or energy storage
- use of mobile substations.

Often non-network solutions can enable deferral of the much larger capital expenditure that is usually associated with network solutions. This provides value in terms of lower lifecycle cost, as well as enabling us to defer a decision when there is considerable uncertainty (such as future load growth).

Demand Management

Demand side management (DSM) provides an alternative to network reinforcement. Generally DSM is an alteration of customer behaviour that occurs in response to incentives provided by the distribution business (or retailer). Incentives include peak pricing or payments for load interruption. Examples of

DSM are tools such as ripple control, which is used to modify demand and using standby generators during peak periods.

We assume no change in the level of DSM activity, i.e. a base level of demand-based initiatives are included in our load forecasts, primarily ripple control, but also some demand response.

Energy Storage

The use of energy storage technologies, such as batteries, could enable us to defer or avoid expenditure on network development. The key network benefit would be peak reduction, although they could also be used to improve power quality by absorbing excess generation capacity from distributed generation sources to mitigate fluctuating voltages.

Battery storage is relatively expensive and its uptake in New Zealand is in its infancy. In some situations, mainly in remote rural areas, installing combined generation and battery storage units could provide an economic alternative to long service lines.

In the longer term battery storage systems will have valuable applications for both lines companies and residential customers. They offer significant potential for increased reliability and resilience of supply, potential for deferring network reinforcements and lifting network utilisation, improving network stability and maximising the value from distributed generation sources. The cost of this technology is linked to the mass production of electric vehicles and is projected to be an economic alternative to conventional grid-supplied electricity during the AMP planning period.

Methanol and gas-fuelled fuel cells offer an alternative power source for small users in remote locations where a gas supply already exists. This existing technology is increasingly being used as an alternative energy source for telecommunications, and could also provide an energy efficient alternative for residential sized loads.

Our forecasts assume that storage devices do not have a material impact in terms of peak demand reduction during the planning period.

Cost of Service Tariffs

It is anticipated that many different types of customer devices, including distributed generation and battery storage, will be connected to electricity networks in future. These new devices may be able to respond to price incentives via customer participation using smart metering. Many of the proposed future network solutions will rely on providing effective incentives.

Deploying smart meters that provide half hourly metering could encourage customer owned smart appliances to move load away from peak periods. We will monitor this technology with a view to assessing if it can be used to encourage customers to reduce their demand during faults on our networks, as this may enable us to defer some network upgrades.

A second benefit for the use of smart metering data is to improve service levels. The information could allow us to identify load trends and thus refine network design standards on the low voltage networks, address issues with power quality and proactively identify faults and potential safety concerns.

Mobile Substations

Mobile substations provide an alternative option to building fixed redundancy into the network. The ability to deploy mobile substation transformers also provides significant regional resilience to our operations. Mobile substations are usually used at N-security substations to avoid planned outages when undertaking routine maintenance on tap changers and transformers.

6.5. GROWTH AND SECURITY INVESTMENTS

The previous sections described the key drivers for growth and security investments and our approach to determining a preferred solution in each case. This section discusses how we develop proposals for each of the preferred solutions. As the operating environment changes the investments forecast for the mid to latter part of the planning period may need to be refined.

6.5.1. Solution Prioritisation

The network development projects listed in this section are mainly driven by increased capacity and security requirements as a result of load growth. Where economic, we have selected solutions that meet our security of supply standards.

This ensures that our network configuration and capacity is constructed in a consistent way and the impact on our reliability of supply service levels will be predictable.[89]

Prioritisation of network solution projects is a relatively complex process. In addition to economic benefit and the severity of the need, we consider the following secondary factors when prioritising across a set of network development projects.

- **Customer expectations**: we give priority to the constraints that are most likely to impact customer service through prolonged and/or frequent outages, or compromise power quality (voltage drop).
- **Compliance**: our aim is to maintain compliance with all relevant legislative, regulatory and industry standards. Priority is given to projects that address any compliance gaps.
- **Contractor resourcing constraints (deliverability)**: we aim to schedule work to maintain a steady work flow to contractors. This reduces the risk of our contractors being either over or under resourced.
- **Coordination with local authority civil projects:** we aim to schedule our projects to coincide with the timing of major civil infrastructure projects by local authorities. The most common activity of this type is coordination of planned cable works with road widening or resealing programmes to avoid the need to excavate and then reinstate newly laid road.

After assessing their relative priorities, the knowledge, experience, and professional judgement of our asset management team is relied upon to make the final decision regarding the exact timing of an individual project within the 10-year planning window.

89 As noted earlier, reliability of supply is affected by many factors. Network configuration and capacity is a major factor, but not the only one.

When the project selection process is repeated, all projects (including new additions) are reviewed. They may be advanced, deferred, modified, or maintained in the planning schedule, or removed from the programme.

Projects that are not included in the next year's plan, but we believe need to proceed during the planning period, are provisionally assigned to a future year in the 10-year planning window.

6.5.2. Planned Growth and Security Projects

This section provides summaries of the growth and security projects we intend to undertake during the planning period.

Box 6.1: Cromwell substation transformer replacements

This project involves replacing the power transformers at Cromwell substation with two new 24 MVA transformers on new bunded foundations, together with associated works.

This project will address a number of significant issues with the existing assets (the "needs").

The main need is capacity and security. Peak load already exceeds secure (N-1) capacity of the existing transformers and is growing strongly. Even with the mobile substation in place, peak load is nearing a level whereby supply will not be secure.

Other important needs in this situation are:

- **Environment:** the existing transformers have no bunding for containing oil leaks. A major leak would create a significant environmental hazard
- **Seismic resilience:** the transformers, foundations and overhead structure do not meet our (IL3) seismic standards for existing zone substations.

Options considered included constructing an additional substation on another site to offload the Cromwell load, or installing a third transformer. These options were discounted based on risk and future-proofing issues. Continued use of the mobile substation was not feasible as it would not fully address the capacity and security issues.

The proposed solution will resolve all of the key issues. It will also reduce multiple minor risks around safety and network reliability, and will enable efficient integration with other local project works, such as 11 kV distribution upgrades.

Box 6.2: Spare 5 MVA Transformer

This project involves procurement of a spare 5 MVA transformer, construction of a live storage site, and construction of a permanent quick response mobile substation parking bay at the Alexandra zone substation. The transformer will be stored centrally in the network.

This project will meet the need for capacity and security. The mobile substation will improve system security on our Central Otago network. The existing 33 kV mobile substation is now covering a large number of transformers. If one of these transformers fail, the mobile substation could be required in one place for an extended period until a new transformer is procured, and would be unavailable to cover other failures or allow for normal maintenance activity.

The project will be completed by September 2019.

Box 6.3: Arrowtown substation rebuild

This project involves rebuilding Arrowtown substation with new larger transformers to achieve N-1 capacity of 24 MVA. It will also increase the total number of 11 kV feeders and replace the 33 kV outdoor bus and fuses protecting the transformers with 33 kV switchgear to improve safety, transformer protection, and improve operational flexibility. The aged building, protection and other secondary equipment will also be upgraded to bring the substation up to modern seismic, and other, standards.

This project will address a number of significant issues with the existing assets (the "needs"). The main needs are:

– **Capacity and security:** peak load is forecast to exceed secure (N-1) capacity of the existing transformers towards the end of the planning period and is growing strongly
– **Risk mitigation:** the existing transformers are protected only by 33 kV fuses, so there is a risk that a minor transformer fault could fail to be detected, and develop into a catastrophic failure.

Other needs in this situation are:

– **Environment:** the existing transformers have no bunding for containing oil leaks. A major leak or catastrophic failure of a transformer could create a significant environmental hazard
– **Flood resilience:** the new substation building will be raised to mitigate the flood risk associated with the existing building
– **Safety:** the rebuilt substation will incorporate modern indoor switchgear with safety features such as arc flash protection, arc containment and built-in earthing.

Options considered included further deferral of the rebuild, rebuilding on an alternate site or building an additional substation, or only replacing the transformers. Installation of smaller (non-standard) transformers was also considered. Load control is already heavily used at this site, and could not be increased economically.

The proposed solution will resolve all of the key issues and will support potential long term upgrades of the subtransmission to Arrowtown. The project is in two stages with the new switchboard to be installed by 2022 and the new transformers by 2025.

6.6. RELIABILITY-DRIVEN INVESTMENTS

Reliability-driven investments aim to minimise the impact of an event, for example by automatically reducing the number of customers impacted by it. Achieving our objectives for reliability requires that we improve our real time management of our networks, including improved control and monitoring capability and increasing the levels of feeder automation.

Our SCADA systems already provide real-time monitoring and control at our zone substations and are currently implementing a multi-year SCCP project to improve our communication infrastructure. During the planning period, our reliability-driven investments will focus on network automation. This is the use of various types of network automation devices, located at selected switching points or critical network junctures, to provide remote or automated operation of distribution switchgear. Automation devices include:

– reclosers and sectionalisers
– automated distribution switches
– line fault indicators.

These types of devices will improve visibility of fault location and network state and improve our capability to monitor and control the network, particularly on distribution feeders. This in turn will allow us to respond faster to events on the network and reduce the number of customers affected by longer outages. It will also enable us to target poor performing feeders. In the short-term, this will help to stabilise network reliability. In the longer term, our renewal programmes will help address the root causes of deteriorating network performance – ageing assets in deteriorating health. The reliability-driven investment work is particularly important in the interim until the reliability benefits of renewed assets are realised. We are developing a plan for implementing these devices, including the determination of a commencement date.

6.6.1. Reliability-Driven Investment Planning

We use a simplified version of the network development process (described for growth and security investments), for reliability driven investments. This process involves identifying needs, assessing options and selecting a preferred solution.

Investment Drivers

The key driver for reliability-driven investments is the performance and quality of service received by customers on different parts of the networks. Reliability investments support our objective to improve overall network reliability to acceptable levels, while minimising the associated costs. This reflects our understanding of our customers' preferences. The main drivers for undertaking these investments are:

- reducing impact of outages: by reducing the severity (extent and duration) of outages. This is particularly effective on heavily loaded or older circuits where the impact on customers may otherwise be unacceptable
- increasing network control: automation increases the level of central oversight and control we have on our network. This increases our operational flexibility and improves the real-time control of our assets
- addressing poor performance: they can be used to target feeders with relatively poor performance in terms of reliability (worst-performing feeders)
- cost reduction: automation devices are a cost-effective way to address reliability performance and allow the prudent deferral of more expensive investments.

Automation options and other potential solutions are considered as part of our general options analysis process, discussed in Section 6.4 above. Our plan for installing automation devices is based on a lifecycle costing approach. This identifies the benefits associated with additional switching devices, which informs the desired density of switching devices of each type. Our expenditure estimates are based on historical unit rates, including the costs of extending the communications network from our backbone network to each remote device.

6.7. CUSTOMER CONNECTIONS

Customer connections network development is the expenditure to facilitate the connection of new customers to our network. On average, around 1,000 homes and businesses connect to our electricity network every year.

New connections often require investment in network infrastructure. New connections range from connecting a single new house through to a range of businesses and infrastructure. The latter may involve small connections like water pumps and telecommunications cabinets, or large connections such as factories or supermarkets. The consumer connections portfolio also includes works for customers – typically commercial – who want to change the capacity of their existing electricity supply.

The expenditure we incur in connecting new consumers is defined as consumer connections Capex.

We do not use a needs/options process for simple customer connections, although a new connection will enter this process if it triggers the need for reinforcement back into the network.

6.7.1. Connection Process

Where customers wish to connect a new residence or commercial premise, and there are already low voltage lines or cables running past the property boundary, the connection is generally straightforward. The customer need only submit a connection application, normally through their electrician.

In other situations, where there are no existing low voltage lines, or where the new load is significant compared to the capacity of the existing lines, then installing a new connection is more complex. In those circumstances, customers may engage directly with us, or via one of our approved contractors.

We have begun to improve our approach to facilitating customers connections. We are assessing ways to streamline our processes to ensure customers receive a prompt and efficient service through using an optimal mix of internal resource and external specialists, this initiative is discussed further in Section 2.3.4.

Funding

Where a customer connection request (new connection or upgrade of existing assets) impacts assets owned by us, the customer may be required to make a capital contribution toward the cost of works required to establish the new or upgraded connection.

We have a connections policy disclosed on our website[90] that describes when a capital contribution is required. We generally require contributions for the following work types:

- extensions or reinforcements that solely benefit individual customers
- network connections that require new assets to be built.

In calculating contributions, it is important to differentiate our assets from customer assets. Customer service lines, the assets inside a customer's property boundary, are owned by the customer and we do not contribute towards their construction.

90 http://www.auroraenergy.co.nz/get-connected/developers-and-consultants/

Consumer connection Capex contributes to network development at the low voltage and distribution levels. Incremental growth from existing customers can lead to upgrades at distribution level, which we fund. Similarly, reinforcement of our network at subtransmission levels is funded through our system growth expenditure.

6.7.2. Forecasting Approach

Below we explain how we forecast investments in customer connections Capex. Our planned investment for the planning period is set out in Chapter 8.

Expenditure Drivers

Customer connection Capex is externally driven with short lead times. It is difficult to accurately forecast medium-term customer connection Capex requirements. We forecast the number of new connections, and the amount of customer connection Capex and capital contributions, from historical data. Each forecast is independent of the others. Historical data tends to indicate a moderate positive correlation between the number of new connections and customer connection Capex. Historically, we have seen significant year-on-year variation in both customer connection Capex and capital contributions.

Investment in 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.

At the time of writing, we are in discussions regarding the new Dunedin Hospital and an upgrade to the Remarkables ski field. We are also aware of the potential for a large upgrade at Cardrona ski field. No provision has been made in the AMP for any of these projects.

7. ASSET MANAGEMENT ENABLERS

This chapter discusses the business functions and non-network assets that support our electricity network. We use the term 'asset management enablers' to describe the following:

- **Asset management capability**: includes the competency and capacity of the staff and processes that support our day-to-day asset management activities.
- **Business support**: includes the capacity of supporting processes (e.g. human resources and finance) and the staff that directly support our day-to-day asset management activities. Facilities and motor vehicles are also included in this category.
- **Information Communications and Technology (ICT)**: sets out our approach to delivering our ICT strategy and providing continuous support for our business in a fast-changing environment.

Of these areas, we plan to increase our asset management capability and internal ICT capabilities. These step changes require increased investment over the planning period, as set out in Chapter 8.

7.1. ASSET MANAGEMENT CAPABILITY

In the following sections we discuss aspects of our asset management capability including:

- our organisation's overall capability following the separation from Delta, and the required future competencies of our workforce
- results of our latest asset management maturity assessment (AMMAT)
- our asset management development plans.

7.1.1. Current asset management capability

Chapter 2 explained that we recently formed a standalone electricity network business following our separation from Delta. During the separation, we retained highly-skilled staff with good technical capability in many areas. However, the separation has led to a need for additional capability in functions such as works delivery management.

We have identified issues on our networks that need to be addressed, and are aware we will need to deliver increased work volumes on our networks. To do so, we will enhance our asset management analysis capabilities to ensure we manage our assets more effectively. This extends to improving the way we work with our service providers to efficiently deliver our investments. As we increase our activities we will also need expanded work management and delivery capabilities, including the ability to manage our new service provider model. We have begun to restructure our core asset management and planning functions to ensure we have the required competencies and capabilities. This will take time as we recruit the right people, introduce them to the business and facilitate their contributions.

There are other areas where we need to increase our capability, for example, to be able to understand and respond to likely changes in the operating environment (such as the uptake of electric vehicles). Gaps in our asset management capability are reflected in our most recent self-assessment of asset management maturity, which is discussed in the next section.

People play a central role in asset management. To effectively deliver our asset management objectives we need to make sure our people have the right capabilities.

This means the people working for us, directly or through our service providers, will need to have the right capabilities (including in emerging areas such as asset analytics) and be willing to learn and adapt as the electricity sector evolves. The increasing use of small-scale distributed generation, the availability of energy storage applications, and the increasing use of intelligent network devices will have far-reaching implications for the way we operate.

One of our key capability initiatives is developing an asset management competency framework to ensure there is a direct link between our objectives and the skills of our people. A well-performing asset management firm has lines of sight that link its strategies and objectives with the roles and responsibilities of staff. Linking what staff do day-to-day to our objectives is critical if we are to deliver an efficient service to customers and effectively manage long-life assets. Some examples of asset management competency include:

- developing planning and design guidelines
- drafting technical standards
- setting out effective maintenance and renewal strategies and plans
- network analytics including fault trending and asset survivor analysis
- specifying materials and equipment standards
- retaining and communicating specialist knowledge (e.g. for SCADA, protection).

Other success factors for effective asset management organisations include staff engagement, clear direction, and effective collaboration between different teams and functions. We aim to create a shared understanding around required capability and communicate this to staff. Implementing this framework will be an important tool for achieving our asset management objectives.

We have begun to reshape our business and have started a recruitment process with the following objectives:

- achieve a sustainable workforce through effective progression planning and career management
- position descriptions that focus on future capability needs and leaders who drive improved performance
- a high performance culture, where employees feel safe, valued, engaged and challenged
- filling capability gaps with the right high-performing people at the right place and time
- values and behaviours are consistent across the whole organisation.

The transition to a fully self-sufficient asset management organisation will take time. Developing our asset management capability will be a major focus for the next five years. Maturing our approach will enable us to achieve consistently effective asset management outputs. This is a particular focus for us, as evidenced by our objective to achieve ISO 55000 certification by 2023.

7.1.2. AMMAT Assessment

We undertake periodic reviews of our asset management maturity using the AMMAT assessment tool.[91] This consists of a self-assessment of our maturity compared to good asset management practices.

When preparing our previous assessment (set out in our 2016 AMP), Delta engaged an external consultant to undertake the assessment. This resulted in an overall average AMMAT score of 2.9.

For our 2018 assessment, we arranged for a group of our own management and staff to reassess our asset management maturity taking into account the EEA guide.[92] We found that our asset management systems require significant improvement and that these should be embedded into our BAU practices before an overall score close to 3 could be justified. Reflecting this, our internal reassessment produced an overall average AMMAT score of 1.94.

Figure 7.1: Comparison of our AMMAT scores by assessment area

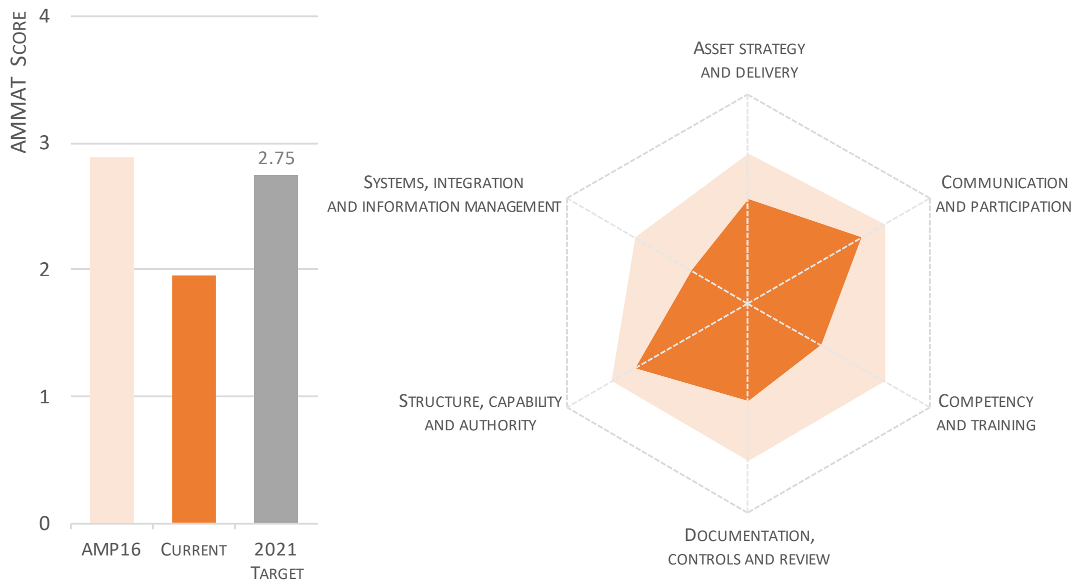


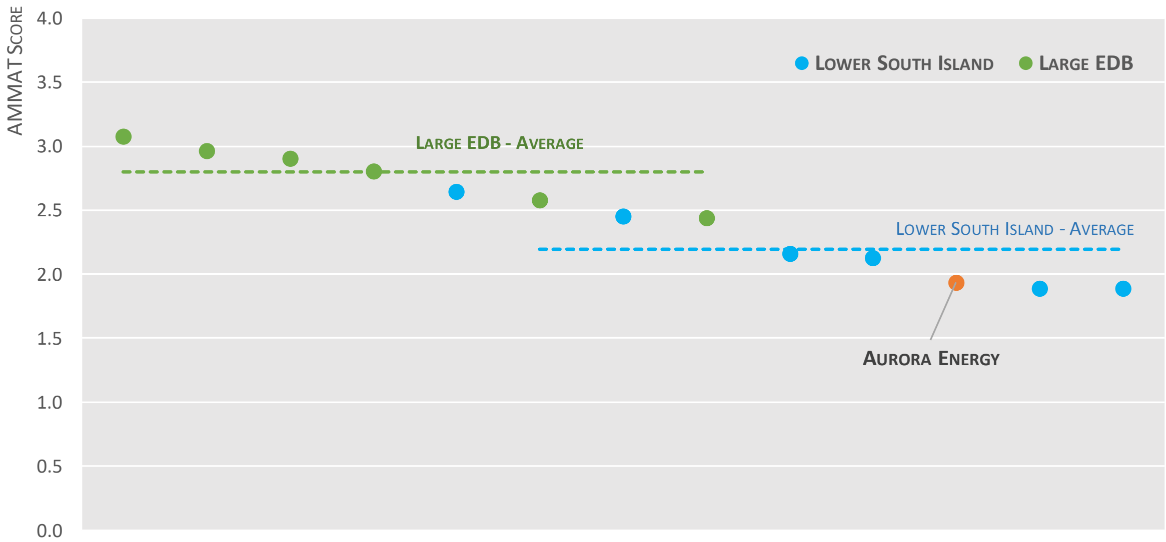
Figure 7.1 compares our 2018 self-assessment with the 2016 AMMAT scores. The results of the 31 AMMAT questions have been grouped into six assessment areas, with the scores presented as the average score of several assessment questions.

We believe the 1.94 score reflects a frank assessment of our capability against the capability levels needed to manage our network effectively over the planning period. It indicates that we have a good understanding of asset management principles, but are well short of having effectively embedded these in practice. Our revised AMMAT score places us at the lower end of the range of the self-assessments published by other electricity distribution businesses (see Figure 7.2).

91 As an electricity distributor we are required to undertake and publicly disclose the AMMAT self-assessment results (Schedule 13 of the Electricity Distribution Information Disclosure requirements).

92 Electricity Engineers' Association, AMMAT — Revised Guide (May 2014) available here.

Figure 7.2: Comparison with a selection of EDBs



The revised scoring highlights the areas where significant improvement in our asset management system is required. We have used this review of our asset management maturity as an important input to the development of our asset management development plan. The overall aim of this improvement effort is to achieve an average AMMAT score of at least 2.75 by 2021 and to build on this to achieve ISO 55000 certification by 2023.

Figure 7.3: Comparison of our current scoring versus our 2021 target and industry averages

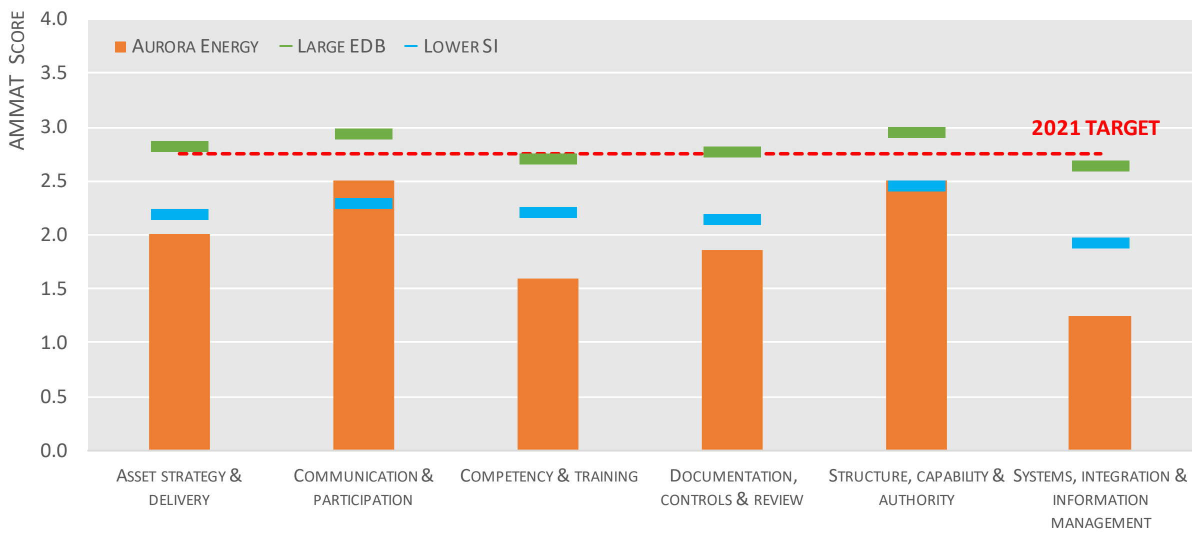


Table 7.1 (see next section) presents a summary of our asset management development plan. We have grouped these improvement initiatives to allow us to focus clearly on the main areas of need and to minimise overlap. As a result, these topic areas differ from the summary categories shown in the AMMAT illustration above.

7.1.3. Asset Management Development Plan

Our AMMAT score is a frank assessment of our current capabilities and strengths, as well as shortcomings. Our review indicated a good understanding of the core principles of asset management principles, but the result falls well short of the standard expected from a mature asset manager. We do not consider this sufficient and accordingly have put in place a plan to improve our asset management capability.

Continuous improvement will be critical if we are to operate successfully in a changing environment. To keep up with our customers' evolving requirements and expectations and to maintain good practice asset management, many of our practices need to improve. We have identified several areas where we need to improve if we are to achieve our goal of good industry practice.

Understanding the maturity of our asset management practices is necessary to determine the scope of asset management improvements proposed in our CPP application. We plan to address the identified shortcomings, to the extent possible, in advance of the application. Some elements will require more time and additional capacity and capability will not be fully achievable prior to submission. We plan to address these deficiencies during the CPP period.

Asset management improvement areas

Our asset management improvements need to be underpinned by strong analytical capability. If we are to successfully optimise future investments and manage network risk there will be an increasing need for reliable information and expanded capability, and improved systems and data. Accurate and reliable asset data and modelling is an essential input.

The shortcomings we want to address as part of an asset management improvement journey are consolidated in our Asset Management Development Plan (AMDP) and are summarised below.

- Strategy and planning: we plan to develop fleet strategy documents and plans for each of our asset fleets, to support optimisation of asset interventions across the asset lifecycle.
- Works delivery: we are planning significant levels of on-going expenditure on the network over the AMP period. Improving our delivery capability will help ensure our expenditure is prudent and efficient, and that we contain costs and limit price increases to customers.
- Reliability management: we have put in place a dedicated work programme to improve our overall reliability performance and to address historical breaches of the quality standards (further detail is set out in Appendix C).
- Competency: we will develop our asset management capability through effective recruitment, development of our staff, and ensuring appropriate competency levels and breadth of skills.
- Risk and review: establishing effective feedback and review mechanisms to provide assurance that objectives are being achieved. This will support continual improvement of our activities.
- Asset management decision-making: improvements to the tools and analysis approaches used to support our asset intervention decisions.
- Asset knowledge: define and document key requirements for asset and network data to support decision-making, including master data, condition data, work and defect history, and performance records.

We have started to develop the relevant documentation, systems and processes to support these efforts. An asset management engagement plan will lift the profile of our asset management system across the company and other stakeholders. It will set out how we communicate with stakeholders that inform our strategies, objectives and plans. As discussed above, we plan to develop a competency framework to strengthen capability across the functions of our asset management system. An asset information strategy will be used to improve our asset management information practices.

Summary of Asset Management Development Plan

We have developed a set of focussed initiatives to achieve the required improvements in capability. These initiatives are reflected in our planned expenditure on asset management capability through our System Operations and Network Support (SONS) portfolio (refer to Chapter 8). Implementing these initiatives will drive an uplift in SONS expenditure relative to historical levels but is an essential component of delivering our AMP investment plans and ensuring we have sufficient capability and capacity to meet the needs of our stakeholders. Table 7.1 presents the main improvement initiatives, by topic area.

Table 7.1: Asset management capability improvement initiatives

Area	Initiative	Summary
Competency	ISO 55000 Certification	We will identify and address the necessary steps to achieve ISO 55000 certification by 2023.
Competency	Competency framework	Develop a competency framework and provide targeted training to meet business needs, broaden technical skill-sets and grow our leaders.
Competency	Build and retain capability	Review and amend our people frameworks, systems, and processes to ensure they are relevant and can attract, engage and retain quality people and motivate high performance.
Reliability management plan	Various	This will focus on ensuring we can effectively meet our future quality standards and deliver a reliable service to customers (see Appendix C).
Reliability management plan	Post-event analysis	Implement post event analysis 'protocol' and lessons learned framework to drive improvements.
Strategy and planning	Fleet management plans	Develop a suite of dedicated fleet management plans that will set out planned improvements in asset information, condition assessments, forecasting tools, cost estimation, and solution options.
Risk and review	Improve review and feedback processes	Establish effective feedback and review mechanisms to provide assurance that objectives are being achieved and to support continual improvement.
Risk and review	Review practices	Establish regular self-reviews that will assess the continuing suitability of our asset management policy, strategy, objectives, plans and delivery.
Organisation and people	Appropriate structures	Review organisational structures, processes, roles and responsibilities and contractual relationships. Effective leadership will be a key aspect.

AREA	INITIATIVE	SUMMARY
Risk Management	Business continuity planning	Undertake a strategic review of contingency preparedness and emergency response capability.
AM decision-making	Asset criticality	Extend the application of our pole and overhead lines asset criticality framework to a wider group of assets. Criticality may incorporate a number of dimensions depending on relevance to the asset type.
AM decision-making	Network planning	Our demand forecasting methodology and load flow models will need to be updated and expanded to model future load scenarios. These innovations are important if we are to pursue 'least-regret' investments
AM decision-making	Improve lifecycle analysis	Improve approaches used for decision-making across the stages of an asset's life through new analysis and tools.
AM decision-making	Asset health	Refine asset health models for major asset types, including introducing multi-factor models for the higher value or higher risk asset types.
AM decision-making	Asset failure risk	Formalise and expand the use of asset health measures and integrate this with our evolving criticality framework to capture asset-failure risk.
AM decision-making	Cost estimation	Improve in-house cost estimation capability, which incorporates feedback from systematic reviews of outturn costs of delivered works.
Works delivery	Process development	Develop and implement improved works management capability for capital projects delivery, maintenance, and vegetation management, including necessary information system improvements.
Works delivery	Multi-party process development	Develop and implement a new contracts management capability to manage multiple service providers and increased tendering of works.
Works delivery	Improve delivery and planning interfaces	Review the internal communications required to deliver the works plan, including information handovers from planning to delivery, and the feedback required from delivery.
Asset knowledge	Asset information strategy	Develop and implement an asset data quality strategy that will ensure our asset managers and operations staff are provided with comprehensive and accurate asset and network performance data.
Asset knowledge	Asset information roles	Develop an implementation plan to drive improvements in asset information collection and data quality. This will include clarifying the roles of data owners and stewards.
Asset knowledge	Asset data structures	Define and document key requirements for asset and network data to support decision making, including master data, condition data, work and defect history, and performance records.

The need for this expanded range of competencies and capabilities and the capacity required to adequately manage our network investment requires increasing expenditure in our SONS portfolio. Finding the right people and developing the skills required will take time. However, it is a prerequisite for our planned improvements that we have the right people and supporting systems in place.

7.2. BUSINESS SUPPORT

Business support includes the business functions that support our network distribution operations. This includes corporate functions such as finance and human resources that directly support our day-to-day asset management activities. It also includes ICT-related Opex.

7.2.1. Business Functions

Business Support Opex covers expenditure on direct and indirect staffing costs and external support, as well as advice we use to complement our internal resource. The key functions supported by this expenditure include:

- Health and safety: providing leadership and coordination of safety policies and approaches in support of our operational teams, including contractors
- Finance: includes managing our working capital and debt, purchasing and transaction functions, financial analysis, corporate reporting, and advice
- Commercial and regulatory: supports compliance with statutory requirements, including regulatory and environmental obligations. This function is responsible for contract management for large customers.
- Human resources: is responsible for attracting and retaining capable and effective people, managing skills and competency development, and fostering a positive working environment. This will be increasingly important as we grow our capability and competency levels over the planning period.
- External relations: manages our day-to-day customer interactions, stakeholder engagement, consultation, and general communications.
- Insurance: consists of a suite of general insurances appropriate for a business of our type and size, with the main policies providing coverage for material damage and business interruption, various forms of liability, and policies to cover vehicles and corporate travel.
- Corporate governance: costs associated with corporate governance and supporting the activities of our Board, including fees and associated costs. This ensures that our business is governed by a team of knowledgeable and experienced directors.
- Compliance activities: there is a range of fees we incur in order to meet legal and regulatory requirements, including audit fees related to statutory and regulatory audits.

These functions all support our electricity asset management activities. Opex related to these activities is classified as non-network Opex. Below we discuss some of the key drivers for this expenditure over the planning period:

- Transitional arrangements: following separation from Delta we have put in place external support for some functions as we continue to build internal capability.
- Staff numbers: directly impacts business support costs. As our activity levels grow we will require increasing numbers of capable staff. Salary and indirect costs (e.g. consumables) are driven by overall staffing levels.

- **External labour market**: staff salaries and other benefits are influenced by the general employment market. Demand for skilled staff, particularly regionally, will impact the level of competitive salaries.
- **Business support requirements**: as our network work programme expands, work volumes for areas of support functions will increase.
- **Regulatory and compliance requirements**: we incur a range of costs to meet statutory obligations. This includes regulatory obligations under the Commerce Act (for example, auditing Information Disclosure statements and price-path compliance statements) and auditing of financial statements.
- **ICT capability requirements**: our staff numbers will increase as we deliver increased work volumes. As a result, the number of people using our ICT systems will increase. Licence agreements and costs for third party support and hardware are impacted by headcount.

Our Business Support Opex forecast is set out in Chapter 8.

7.2.2. ICT Related Opex

ICT-related Opex is included in Business Support for Information Disclosure purposes (note our ICT Capex is included in the non-network Capex forecast).

ICT-related Opex includes expenditure related to software licensing, as well as ongoing support such as bug fixes and service packs. It also includes internet, network, and data communications, customer contact technology and the hosting, server and storage, backup and disaster recovery infrastructure on which our business applications run. Our systems engineers and third-party supplier agreements with appropriate service levels support all business-critical 24/7 and real-time systems.

Enterprise systems are initially supported by the ICT Operations team with supplier agreements in place for more complex support and subject matter expertise.

All costs are actively managed. Historically most were purchased, but they are increasingly moving to subscription-based costs, as discussed in the next section.

We outsource our data centre requirements and core communications network. This service includes resolving incidents that affect our operations. The data centres are tier 3 or tier 2.5 and are managed as such, including independent compliance audit and review.[93]

Our service management ensures that proper procedures and controls are in place for the delivery, distribution and tracking of ICT services along with monthly service level monitoring and reporting against agreed levels. We record and track all ICT incidents and fix minor or high-priority incidents within agreed service levels. Incidents that require significant analysis or investment are prioritised into the annual capital programme.

7.3. INFORMATION, COMMUNICATIONS AND TECHNOLOGY

This section sets out our approach to delivering our Information Communications Technology (ICT) strategy. It explains our current and planned ICT capabilities and how we manage our ICT assets. ICT

93 Data centre 'tiers' reflect the relative levels of redundancy and uptime provided.

Capex is classified as non-network Capex (along with assets such as facilities and motor vehicles owned by the business).

7.3.1. Overview

ICT services that support our asset management and corporate functions were historically provided by Delta. Since separation we have begun to develop standalone systems to replace functionality and processes that were provided under these previous arrangements.

Since the separation our ICT / Technology and Information group has taken responsibility for:

- ensuring the required technology, communications and information is provided and operated efficiently to assist in meeting customer requirements for reliable and safe energy delivery
- storing and providing current and accurate information about the extent and performance of the network and assets
- providing cyber security capability to safeguard the network and its assets
- monitoring technology, customer and industry trends, assessing their effectiveness and determining the optimum time to implement those best suited to meet business needs
- ensuring technology and information plans provide effective direction to network performance and asset management planning and delivery.

To do this our ICT team delivers and supports the infrastructure, servers, communications technologies, applications and data that interface with distribution-network technology, and connect to Transpower and retailers.

Our initial focus has been on establishing working systems to support our day-to-day asset management activities. As these systems go live we will turn our focus to additional capability and lifecycle management of our systems. Our approach to ICT planning is illustrated in Figure 7.4.

Increasingly, and also reflecting the rapid rate of change in the technology industry, ICT solutions are being sought and provided on an as-a-Service (aaS) basis. Current business support infrastructure is already provided in this way, with distribution network infrastructure being fully transferred to the existing aaS infrastructure suite during 2019. Over the next five years we will seek to purchase the majority of required applications and communications aaS and likely move from private to public cloud hosting. Where efficient this will effectively replace Capex with Opex but at similar or lower total expenditure over a five to ten year period. This may have an impact on our actual Capex and Opex expenditures in the outer years of this plan. Choices on the timing of change will be made using an appropriate financial benefit model. The rationale for adopting aaS where possible includes:

- increasing our evergreen footprint (where upgrades are factored in as they are available)
- increasing the opportunity to take advantage of new technologies and services
- decreasing the upgrade overhead and consequent business impact
- increasing the standardisation of services provided to business and customers.

To help with planning our ICT requirements we have identified the following five business service categories.

Table 7.2: Business Service Categories

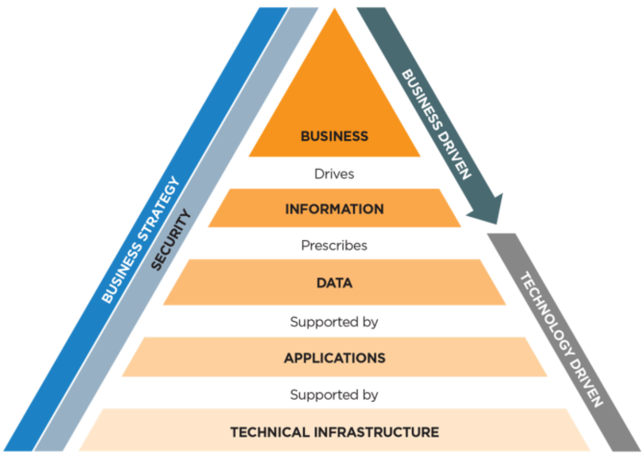
Business Service	Description
Asset Management	Support the creation, management and operation of assets and asset management. Support the forecasting and planning of distribution asset maintenance and our data collection systems.
Operational Technology	Includes SCADA and associated systems to support the core distribution services, and the management of substations through the provision of real-time and time-series information.
Customer and Commercial	Systems and technology used to support customer care and management, billing, regulatory compliance and commercial activities.
Corporate	Systems used to support our corporate operations through human resource, finance, risk, audit and compliance, legal and property services.
Enterprise Technology and Infrastructure	Support ICT services and infrastructure (servers, operating systems, data centres, storage, backup), identity and access management, telecommunications, network, security, end-user device, and business continuity and disaster recovery capability.

ICT solutions change frequently as an increasingly large number of devices and processes depend on digital technologies and communication. Most of our capitalised ICT assets have a depreciation life of less than five years, reflecting the rapid rate of innovation and change in the technology industry.

7.3.2. ICT Governance

All ICT development starts with a business need. These needs are assessed, and our response is guided by our executive team. This ensures that ICT has a whole of business overview and undertakes ICT-related governance for all initiatives. Initiatives are informed by technology and information principles which encompass business, information, data and technical architecture, as shown below.

Figure 7.4: Enterprise Architecture Framework[94]



The following principles help govern our overall technology environment. Although these principles are not new to us, they will increasingly drive our selection, implementation and operation of technologies.

94 This is a variant of a typical enterprise architecture framework.

Box 7.1: Technology and Information Principles

The following principles govern our technology environment

- We are an electricity distribution business. We use technology.
- We have a managed/architected technology environment (data, applications, services, integration, IT, Operational Technology, communications, security, structure / organisation).
- Data is an asset and must be treated as such. This includes planning for it, creating it, and safeguarding, trusting, maintaining and retiring it.
- We complete our programmes of change, especially those involving technology, over reasonable and finite timeframes.
- We use third-party hosted, service-based solutions where possible. There is no need for us to 'reinvent the wheel' and we can re-engineer business processes to fit.
- Where no suitable hosted solutions exist, we will buy solutions (e.g. software) supported by third parties. We will avoid building and supporting solutions ourselves, where possible.
- A technology solution is not required for every issue. We will not modify or customise technology or technology solutions to meet 100% of requirements and requests.
- We acquire and implement solutions and services where integration is pre-built by third parties wherever possible, and which is already configured (or is easily configurable) and readily provides data for reporting, analysis and presentation. Where no pre-built integration exists, we will use a standard integration framework when connecting our applications and services.
- New technologies will be required from time-to-time whether sought by users or through identified business or customer need. All new technology is reviewed against these principles.
- Introduction / implementation of technology will include its effective roll-out to users. This comprises communication and user training and measuring user satisfaction with the business outcome.

These principles increasingly drive our selection, implementation and operation of technologies.

7.3.3. ICT Strategy and Planning

ICT strategy and planning over the AMP planning period is undertaken over three horizons.

- **Horizon 1:** covering the period up to 2020
- **Horizon 2:** covering the years 2020 to 2023
- **Horizon 3**: covering a period from 2023 onwards

The tables below set out the summary objectives for each of the five technology portfolios across each horizon. Given the rapidly changing nature of ICT solutions, Horizon 3 only includes our current investment plans and is subject to change.

All ICT investment is informed by the enterprise technology and information principles, and governed as set out in Box 7.1.

Table 7.3: ICT Horizon 1 Investment Focus

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Implementing new capability to support rapidly developing asset information strategies and the increasing amount of data being obtained from both real-time systems and growing field capture of asset information.
Operational Technology	Upgrading the capability of the recently implemented Advanced Distribution Management and Outage Management Systems to allow more field-based visibility to improve worker safety and improve customer service for outages.
Customer and Commercial	Maintaining billing systems, implementing increased customer care and service capability.
Corporate	Continued support of existing systems while improving operational efficiency.
Enterprise Technology and Infrastructure	Standardising our communications network to prepare for the forecast growth in data from distributed systems and assets and the increasing use of sensors. Further improving our cyber security capability. Expanding the reach of aaS. Separating Aurora Energy infrastructure and services from Delta.

Table 7.4: ICT Horizon 2 Investment Focus

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Extending and embedding advanced analytics capability to support condition-based risk assessment and use of near real-time asset health indicators. Continuing integration with other core systems and embedding and supporting the new capability.
Operational Technology	Extending distribution management capability further into the low voltage network. Increasing capability for managing distributed energy and sensor technology.
Customer and Commercial	Improving customer case management and customer services.
Corporate	Enhancing existing financial tools. Re-platforming employee management and payroll systems with hosted aaS capability.
Enterprise Technology and Infrastructure	Optimising our communications network taking advantage of merging radio and mobile.

Table 7.5: ICT Horizon 3 Investment Focus

BUSINESS SERVICE	INVESTMENT FOCUS
Asset Management	Adding/improving capability to support external data sets. Increasing work automation. Potentially undertaking a lifecycle replacement of one or more parts of systems used – GIS, Asset Management, analytics toolsets.
Operational Technology	Potentially moving parts of these technologies to aaS. This may drive a major lifecycle replacement.
Customer and Commercial	Increasing distributed systems capability. Improving operational efficiency.
Corporate	Re-platforming core financial systems.
Enterprise Technology and Infrastructure	Continued focus on efficiency and meeting business needs while taking advantage of new technologies.

7.3.4. ICT Assets

Historically we have maintained our ICT systems to achieve business outcomes, investing in the ICT assets as necessary to support them and replacing them only at end of life. Changes in business needs and an increasingly rapid rate of technological change have driven the need for a more responsive ICT approach. For example, increased investment in our electricity network is driving an increased demand for data, field-based applications and more efficient back-office transactions. We are also seeing increasing demands from safety and network operational requirements.

AaS, public hosted cloud, agile and digitised platforms, applications, infrastructure and services will represent an increasing part of the ICT asset portfolio over the next five years as we work to meet our customers' needs, add value to our business, improve our operating model, and optimise our technology portfolio.

We monitor all ICT systems continuously for performance and capacity, and report our overall performance monthly. Key performance measurements for our major systems including availability, service outages (number and duration) and service level achievement are tracked and monitored.

7.3.5. ICT Portfolios

The portfolio for each business service has been determined by assessing the gap between our current capability and the anticipated future needs of our business. Our Technology and Information Principles regarding our procurement approach help us manage investment and ongoing costs by subscribing to third party-hosted services where possible, buying third party-supported solutions where not and avoiding developing solutions uniquely for ourselves. Our cost estimates for future investment are based on historic spend on similar initiatives (where available), market intelligence and vendor advice.

Over time, we expect the market to make more numerous and attractive subscription services available – including for geographic information systems, work and asset management services and real-time operational technology tools such as SCADA, distribution management and outage management systems. We would expect to exploit these options if they prove efficient – effectively replacing Capex with Opex but at similar or lower Totex over a five to ten year period. This may have an impact on our actual Capex and Opex expenditures in the outer years of this plan.

The following sub-sections discuss the portfolios/initiatives expected to be required for each business service.

Asset Management

Asset management services relate to capabilities that support our core activities including asset inspections, work planning, issuance, job management and recording, as well long-term asset management strategy.

Substantial ICT investment is required in asset management service areas reflecting the need to commission new tools for work and job management, and to improve the collection of, and quality and accuracy of, asset data. This is needed to assist in lifting capability in risk and condition assessment and improving our asset management maturity.

Between RY19 and RY22 – covering Horizons 1 and 2 – we will scope, select and implement new work, job and contract management tools to improve the efficiency of our field work and the quality of the data we maintain about our assets. This will improve our ability to plan how and when to maintain and replace assets to efficiently meet the evolving needs of our customers.

Operational Technology

Operational technologies are the real-time tools we use to run our network – SCADA, and distribution and outage management systems. These systems are critical to the safe and reliable operation of the network and must achieve exceptionally high reliability.

We have carried out extensive work on this portfolio over the last five years for the HV network. Over the next two to three years we will begin to extend this capability to the LV network and increase mobile capability. A lifecycle replacement of our core supervisory control SCADA tool is planned later in the period. Although cloud-provisioned SCADA is not yet commercially available, it is possible that this may be an efficient implementation option for us.

Customers and Commercial

Our customer and commercial portfolio includes billing, case management and regulatory compliance services. We plan to commission new case management capability in parallel with exploiting the ability of our new operational technology platforms to offer improved notifications to our customers around outages and likely restoration times.

Corporate

Our corporate services cover all non-network or customer related activities including finance, HR, legal and property. Our current financial management and HR technology services are relatively mature.

However, there is a need for intervention with respect to the Financial Management system within the planning period because of an expected obsolescence/cessation of product support. The final decision about the most appropriate intervention will depend on whether transitioning to a subscription service (with lower capex and higher ongoing opex) is efficient and practical, compared with capital investment.

Enterprise Technology and Infrastructure Requirements

This covers the enabling technology and generic technology frameworks and platforms that allow us to provide mobile access to business services, integrate standalone data sources and analyse information as well as support the processing, storage and exchange of digital information around the company.

Investments include completion of the overhaul of our voice and digital communications to support operational technologies. Many of the services provided in this portfolio are delivered through cloud services with the result that Capex is relatively low. Investments in these business services are included in our non-network asset Capex and in Business Support Opex.

Appendix E provides further detail on our ICT assets and how these are managed.

7.4. OTHER NON-NETWORK ASSETS

In addition to our ICT assets, we own or lease a range of other non-network assets that are used to support our day-to-day asset management activities.

7.4.1. Facilities

We own or lease a number of facilities, including office buildings and storage sites in both Dunedin and Central Otago. Our facilities management programme aims to ensure that our offices and stores are safe and secure for our employees and contractors, are functional and fit for purpose, support improved productivity and efficiency, and are cost effective to procure and operate. They must also be sized to support future staff growth and materials storage requirements.

The table below summarises the location of our offices and storage sites and their ownership arrangements. The facilities are strategically located throughout our network footprint. This has many advantages, including having employees with local knowledge close to customers and service providers.

Table 7.6: Facilities Assets

AREA	FACILITIES	OWNED/LEASED	MAIN USE
Dunedin	Halsey St	Leased	Main office, control room and storage
	Wharf St	Leased	Warehouse and storage. Likely that Delta will take on these leases.
	Hillside Road	Leased	
Central Otago	Ellis St (Alexandra)	Owned	Storage, part leased to third party
	Barry Avenue (Cromwell)	Owned	Storage
	Hawea	Owned	Residential rental (potential sale)
	McNulty Rd (Cromwell)	Leased	Main office and control room
	Terrace Junction (Frankton)	Leased	Office
	Success St (Alexandra)	Leased	Storage

Technology Assets

The office facilities we operate are fitted out with work stations to accommodate approximately 130 employees. The standard setup of a workstation includes a desk, chair, storage, PC and communication equipment. Our offices also host meeting spaces and relevant office equipment required to operate effectively, such as printers, storage, and meeting room technology. These assets include:

- desktop hardware
- laptop hardware
- monitors and screens
- video conferencing equipment
- other peripherals (scanners, digital cameras).

The key driver of expenditure on these assets is the number of employees, which determines the volumes of desktop computers, handsets and related peripherals required to service their ICT needs.

7.4.2. Motor Vehicles

We have a fully maintained fleet of about 35 vehicles which are generally leased for terms up to 45 months. We typically lease all our vehicles apart from one or two speciality vehicles and six trailers which cannot be leased cost effectively.

Our fleet includes vehicles that fit defined criteria, including that vehicles must have a five-star ANCAP safety rating, low emissions, and be fit for purpose i.e. all-wheel-drive and with suitable ground clearance.

We will periodically undertake lease versus ownership analysis for our vehicles fleet, including comparing the relative cost effectiveness of fully maintained or company-maintained leases. Lease costs for selected vehicle types will be sought from a range of leading fleet providers in New Zealand, with the selection of a provider based on best fit, considering pricing, servicing, and level of support.

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8. FINANCIAL SUMMARY

This chapter sets out a summary of our expenditure forecasts over the AMP planning period. It provides further commentary and context for our forecasts including key assumptions. It discusses our cost estimation methodology, and how this has been used to develop our forecasts for the planning period.

8.1. INTRODUCTION

The expenditure forecasts presented here are to align with our internal expenditure categories and with information summarising the investments discussed in earlier chapters.

Our AMP includes our current best forecasts based on our asset management strategies and using available network information. We expect this profile, particularly later in the period, to be further refined as we enhance our modelling approaches and improve our underlying asset management frameworks. This includes periodically reviewing our proposed levels of investment against our capacity to efficiently deliver the work. These refinements will be reflected in subsequent updates of the AMP.

Box 8.1: Note on our expenditure charts

The charts in this chapter show actual expenditure (grey column) for RY18[95] (1 April 2017 to 31 March 2018) and our forecasts (orange columns) for the remainder of the planning period. Typically, our AMP would include a budget figure for the initial year, however, due to our publication extension (see Chapter 2) we have been able to include a final figure, consistent with our annual information disclosure published in August 2018.

Expenditure is presented according to our internal categories. It is also provided in information disclosure categories in Schedules 11a and 11b in Appendix B.

All dollars are denominated in constant price terms using FY18 New Zealand dollars.

Below we summarise our Capex and Opex forecasts for the AMP planning period. This section provides high level commentary and background on the overall forecasts, together with cross references to chapters where more detailed information is provided.

8.1.1. Total Capex

Total Capex includes the following three expenditure categories:

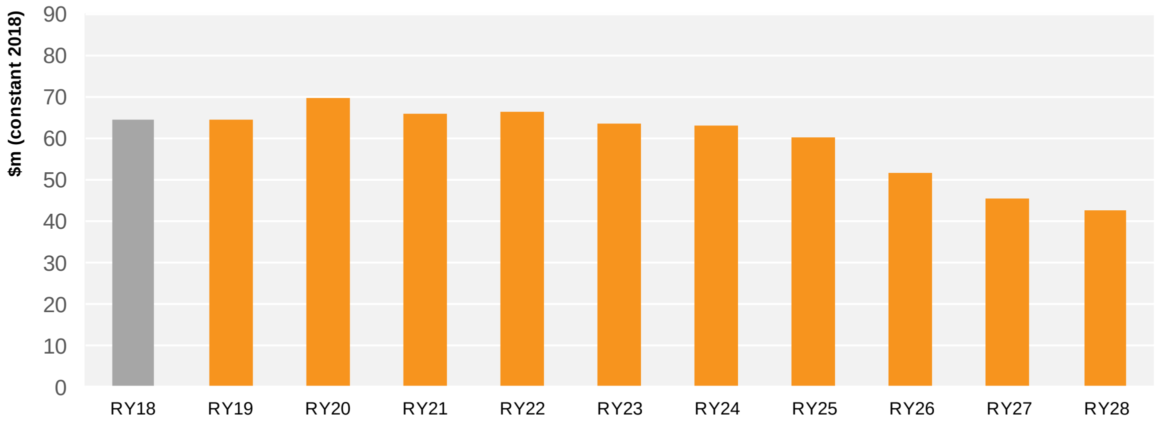
- **Fleet management Capex**: used to renew (replace or refurbish) existing assets on our networks. These investments are discussed in Chapter 5.
- **Network development Capex**: includes investments related to growth and security, reliability-focussed projects, and new connections to our network. These investments are discussed in Chapter 6.
- **Non-network Capex**: includes expenditure on ICT assets and facilities. These investments are discussed in Chapter 7.

The majority of Capex falls within the fleet management category. The increase in total Capex over the planning period relates almost entirely to network expenditure. There is a minor increase in non-

95 Note, our financial year runs from 1 July to 30 June.

network Capex arising from our investments in systems and capability that will enable delivery of increased Capex volumes. Below we set out our forecast total Capex for the planning period.

Figure 8.1: Forecast total Capex over the AMP period (net of contributions)



Planned Capex on our network is broadly consistent with our March 2018 interim disclosure. It continues to represent a significant increase on historical levels. This level of expenditure is needed due to our ageing asset base and is important to ensure a long-term safe and reliable supply for customers. We intend to focus on a number of key fleets and initiatives over the next decade.

The main drivers for the overall spend profile include:

- Maintaining our accelerated pole programme for up to three more years, before returning to steady-state levels (discussed in Chapter 5).
- Increasing crossarm renewals over the period, as we progressively firm-up information on the condition of these assets (discussed in Chapter 5).
- Increasing conductor renewals over the period, as we progressively improve and expand information on the condition of assets in this fleet (discussed in Chapter 5).
- Addressing seismic risk in our zone substation buildings and equipment (discussed in Chapter 5).
- Renewing Dunedin's aged 33 kV cable network, as part of a broader review of the city's network architecture (discussed in Chapter 5).
- Replacement of poor condition assets in other fleets that present safety risks, particularly ring main units (RMU) and air break switches (discussed in Chapter 5).
- Replacing obsolete protection relays, particularly electromechanical and static types. We will replace most of them, with modern numerical types during the planning period (discussed in Chapter 5).
- Network growth investment, to provide the capacity and security required to service growing communities in Arrowtown, Wanaka, Queenstown and Cromwell (these projects are discussed in Chapter 6).
- Implementing ICT systems, and supporting processes, in the early part of the CPP period (discussed in Chapter 7).

8.1.2. Total Opex

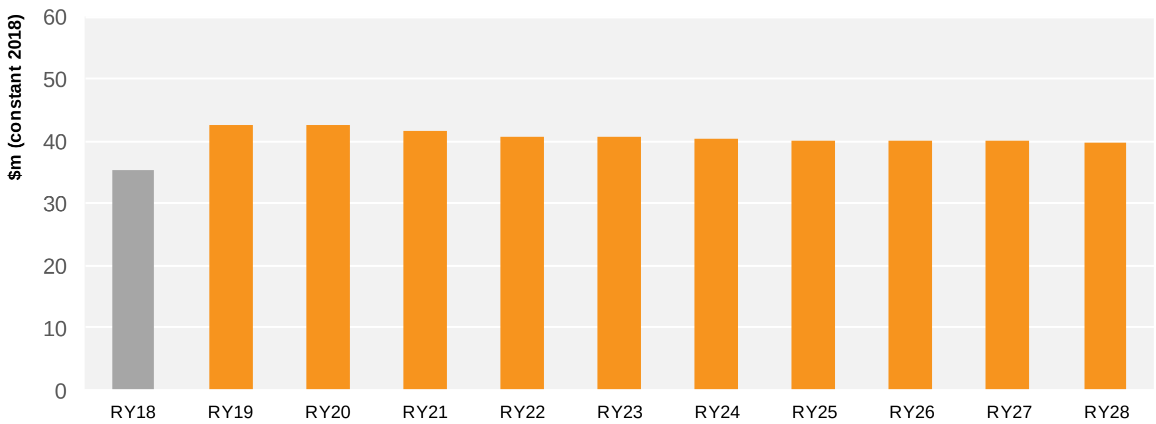
Our current total Opex forecast declines over the planning period, ending the period at about $5m per annum lower than at the start. The profile will be amended as we refine our asset management approaches and modelling, similar to our Capex forecast. These represent our best forecasts using currently available information.

Total Opex includes the following main expenditure types:

- **Maintenance expenditure**: relates to activities to inspect and repair our assets. These activities are discussed in Chapter 5
- **Vegetation management**: relates to the management of vegetation that grows in close proximity to our assets. These activities are discussed in Chapter 5
- **Non-network Opex**: includes System Operations and Network Support (SONS) and Business Support and relates to activities that support the day-to-day asset management of our assets. These activities are discussed in Chapter 7.

As with Capex, total Opex will increase relative to historical levels. This is mainly driven by increased maintenance activities. Opex increases are proposed in some areas where we believe they will provide material benefits to network performance and direct benefits to customers. Increased capability will allow us to optimise total Capex required over the period. Below we set out our forecast for total Opex during the planning period.

Figure 8.2: Forecast total Opex over the AMP period



Following an initial uplift, our overall Opex is expected to decline over the AMP planning period.[96] In the coming two to three years we expect to incur costs related to our continuing transition to a standalone business and to help develop our CPP application. We plan to increase our maintenance and vegetation management activities, although we expect this increase to be offset by savings as we increase the level of contestability amongst service providers.

96 Although not reflected in the long-term forecast, we expect to achieve productivity and efficiency improvements to drive down costs. We have not attempted to model these at this early stage.

Our non-network Opex has increased compared with historical disclosures. This is largely due to the nature of historical contractual arrangements between Aurora Energy and Delta under which Delta provided asset management (SONS) and business support services to Aurora Energy.[97]

Together, the terms of the service agreements have led to relatively flat costs over the past decade or so, as evidenced in Information Disclosures. It should also be noted that historical Business Support disclosures were stated exclusive of ICT hardware and software costs, on the basis that Delta (rather than Aurora Energy) incurred those costs directly.

Upon expiry of the historical contracts with Delta, Aurora Energy directly employed around 100 staff (previously employed by Delta) and began to insource its own asset management and business support (including ICT/Technology) functions. A new Board of Directors, Chief Executive and executive team was also established, and Aurora Energy is now fully focused on developing asset management, service delivery and technology capabilities for the purpose of managing critical risks and driving efficiencies that will serve the long term interests of consumers connected to its network.

The historical contracts with Delta delivered lower SONS and business support costs throughout a period of relatively stable network performance and asset renewal. However, the levels of previously reported SONS and business support costs no longer reflect the forward investments necessary to support and sustain future works, as the company embarks on a further step change in its asset renewal programmes.

The main drivers for our overall Opex spend profile include:

- We plan to bring our vegetation management practices up to good industry practice by embedding our cyclical regime, and adopting risk-based assessment of out-of-zone trees.
- We are adopting improved inspection and assessment techniques so we can better understand asset condition and network risks. Data management practices will be enhanced.
- We plan to complete deferred maintenance on our circuit breakers to return them to good health, and continue to maintain them at defined intervals thereafter.
- We are pursuing improvements in our asset management practices, to achieve industry good practice and to realise efficiencies. This requires us to bolster our internal capabilities and skills.
- We need to increase our project delivery capacity to ensure we can effectively deliver required investments on a greater scale than before.
- Additional business support staff will support our transition to a standalone business and support the delivery of improvements to our ICT systems and capabilities.
- We expect productivity and efficiency improvements to offset upward cost pressures in the latter part of the AMP period.

97 Prior to separation, Aurora Energy owned the network but did not directly employ asset management or business support staff, as those functions were fully outsourced to Delta. Asset management (system operations, commercial and network support) services were provided by Delta under a long-term contract with CPI adjusted fees agreed at the beginning of the ten-year contract term.

8.1.3. Inputs and Assumptions

This section sets out some of the key inputs and assumptions underpinning our forecasts for the planning period. It includes our approach to escalating our forecasts to nominal dollars. Section 8.4 discusses inputs and assumptions relating to our underlying forecasting approaches.

Over the AMP period we expect to face different input price pressures to those captured by a general measure of inflation like CPI.[98] We expect that the input price increases we face over the planning period will be greater than CPI due to factors such as the need to attract and retain skilled staff and the global demand for commodities used in our assets.

To reflect this we have applied different cost escalators to our real price expenditure forecasts. Our escalators have been developed using forecasts of input price indices that reflect the various costs that we face, including material, labour and overhead components sourced from NZIER and World Bank forecasts. These are applied using weighting factors for cost categories, such as conductors, that are impacted by the inputs. These were applied to our real expenditure forecasts to produce the nominal dollar forecasts for the Information Disclosure schedules in Appendix B.

8.2. CAPEX SUMMARY

Information Disclosure specifies the following six Capex categories. We use these categories, with some adjustments to reflect our internal approaches.[99]

- Renewal Capex: is expenditure used to replace or refurbish existing assets on our networks. Our approach for identifying these investments is set out in Chapter 5.[100]
- Growth and Security Capex: is used for investments that increase the capacity of our networks in response to increasing demand or to meet our security of supply standards. Our approach to identifying these projects is set out in Chapter 6.
- Reliability, Safety and Environment: is expenditure that addresses particular expenditure drivers, such as improving reliability or reducing safety and environmental risks.
- Customer Connections: reflects the investments we make to facilitate the connection of new customers to our network. This expenditure is net of capital contributions. Our approach to connecting new customers is discussed in Chapter 6.
- Asset Relocations: is the cost of relocating our assets to facilitate developments by third parties. These are typically undertaken at the request of the New Zealand Transport Agency, councils and developers. This expenditure is net of capital contributions. Our approach to connecting new customers is discussed in Chapter 5.
- Non-network Capex: is our investment in those assets that support and enable our asset management activities. The drivers for these investments are discussed in Chapter 7.

98 All groups Consumer Price Index.

99 Our expenditure, aligned with Information Disclosure categories, is set out in Appendix B.

100 Note that Chapter 5 also refers to replacement and refurbishment.

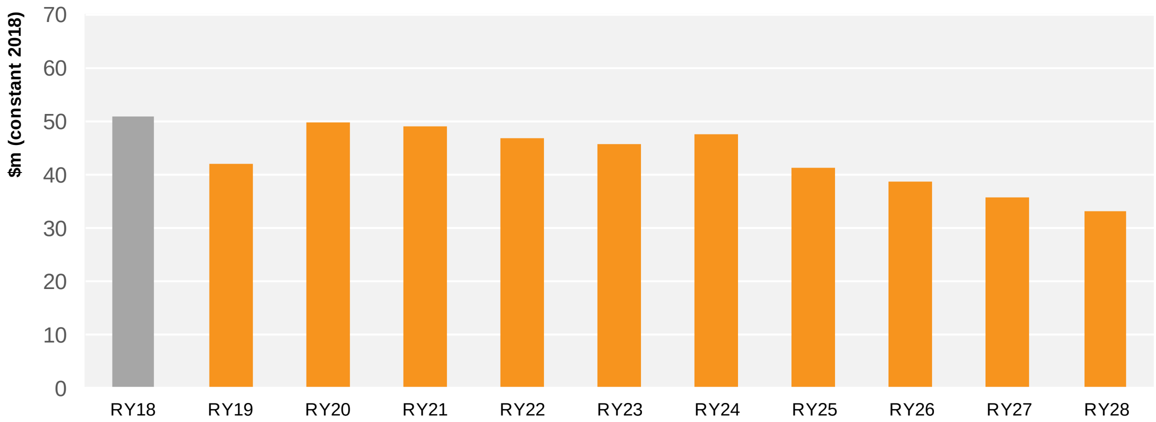
8.2.1. Renewal Capex

As discussed in Chapter 5, our Renewal Capex is split into seven main fleets (or renewals portfolios). These are:

- support structures
- overhead conductors
- cables
- zone substations
- distribution switchgear
- distribution transformers
- secondary systems.

The combined forecast expenditure in these portfolios is shown below.

Figure 8.3: Forecast renewal Capex over the AMP period



The particular drivers for our increased investment in renewing our asset fleets over the planning period have been discussed in Chapter 5. The overall driver is that renewing network assets is essential to maintaining the overall health and condition of a network. Deteriorating condition increases safety and reliability risks due to the higher likelihood of asset failure.

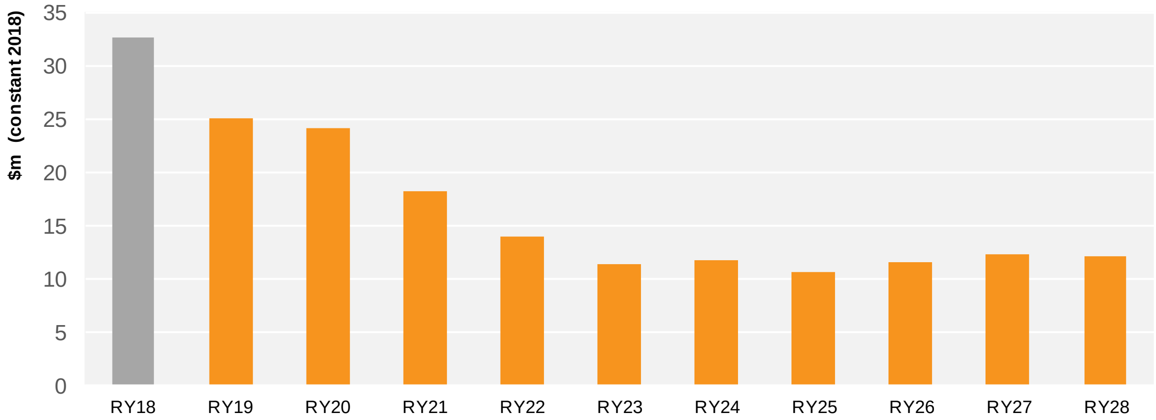
We have seen growing backlogs in required renewals as indicated by asset health, defect volumes and fault rates. Failing to address this will result in unacceptable safety and reliability positions. Reducing the volumes of at-risk assets is a key driver for these investments. To achieve this when a large part of our asset population is approaching end of life requires increased investment.

The following sections set out our planned renewals Capex for each of the seven fleets, presented consistent with our internal categorisation. Appendix B sets out this expenditure using Information Disclosure categories.

Support Structures

Chapter 5 explained that our support structures portfolio includes our pole and crossarm assets. We significantly ramped up expenditure on our pole assets during the Fast Track Pole Programme (refer to Chapter 5 for more discussion on this) and in the subsequent RY18.

Figure 8.4: Support structures renewal Capex over the AMP period



Our planned renewals Capex for support structures over the next two years reflects our ongoing work to replace our worst condition and highest risk overhead structures. Our investment in RY18 to RY20 primarily reflects our response to increasing numbers of poor condition poles and our expectations of the condition of pole assets we will be testing over the next couple of years. We expect to gradually reduce this level of investment from RY19 until RY23 when we should approach a steady-state level of annual renewal. Our proactive crossarm replacement programme will ramp up over the next two years as we continue to compile improved data on this sub-fleet. A sizable crossarm replacement programme will continue through to the end of the planning period.

This increased investment is essential to manage safety risks associated with potential asset failure as indicated by the poor health of our wooden pole assets. It will also reposition our expenditure to a sustainable long-term renewal rate commensurate with the volume of assets. Support structure investment is also driven by the replacement of overhead conductor, such as for the reconductoring of the Waipori lines.

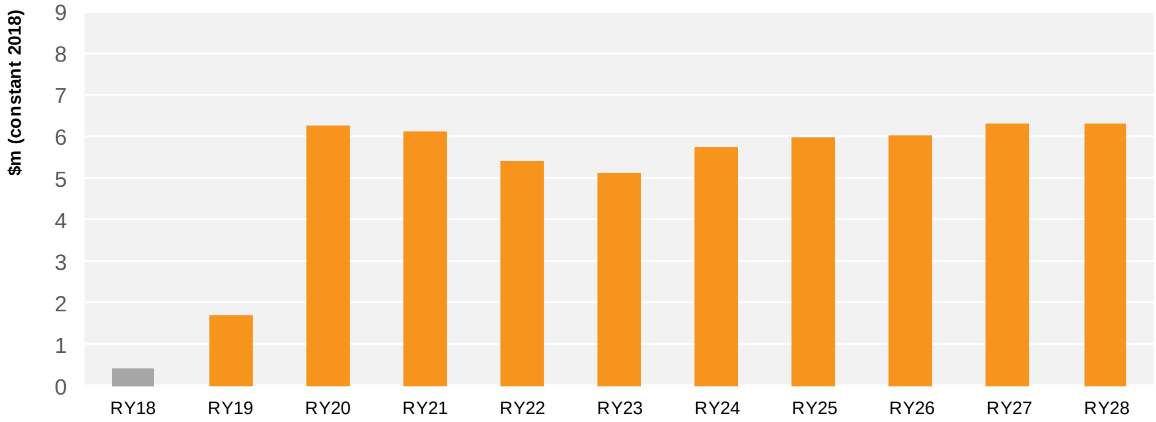
The planned renewals investments will allow us to:

- continue to replace poles and crossarms that are in poor condition
- increase the volume of proactive crossarm replacements to address failure-related safety risks, as indicated by crossarm age, worsening crossarm condition and increasing crossarm faults
- reduce the number of pole defects to manage safety and reliability risks
- undertake several major reconductoring/pole replacement projects
- ensure overhead structures are sized appropriately when associated conductor is replaced.

Overhead Conductors

As discussed in Chapter 5, we have a relatively large volume of aged conductor. At present, our ability to implement an efficient and effective renewal programme is limited by delivery constraints and a lack of conclusive condition information. Based on age and location of our various types of conductor, we have estimated likely replacement volumes over the planning period. Figure 8.5 sets out the forecast cost associated with this work programme.

Figure 8.5: Overhead conductor renewal Capex over the AMP period



We have scheduled several large reconductoring projects on our subtransmission network for the early years of the period to manage risk associated with these assets, for example, reconductoring of the Waipori lines, currently aged copper conductor. Beyond this initial focus on subtransmission, most of the expenditure in this portfolio is on distribution conductor replacement. We need to bring renewal volumes to sustainable long-term levels otherwise both public safety and reliability for customers will be compromised. LV conductor follows a similar expenditure profile to distribution, but at reduced quantities.

We plan to phase the increase in renewal investment to ensure the programme is deliverable. This also allows more time to refine our condition assessment techniques so that we can effectively locate and prioritise conductor sections in need of replacement.

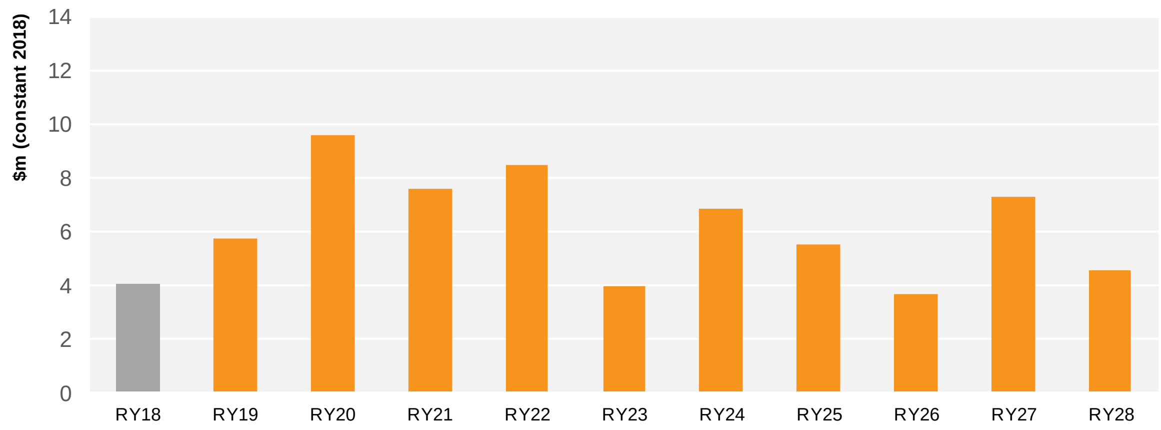
Our planned renewals Capex on overhead conductors will allow us to:

- replace poor health subtransmission conductor, particularly old copper, to mitigate safety and reliability risk
- increase renewal of distribution conductor to ensure we begin to renew this at sustainable levels
- renew LV conductors to effectively manage asset health, particularly in urban areas where safety risks are higher.

Cables

The condition of our subtransmission cable, and the risk associated with a significant failure mean that many of our subtransmission cables are scheduled for replacement during the planning period. We also plan to replace some poor condition PILC distribution and LV cable.

Figure 8.6: Cables renewal Capex over the AMP period



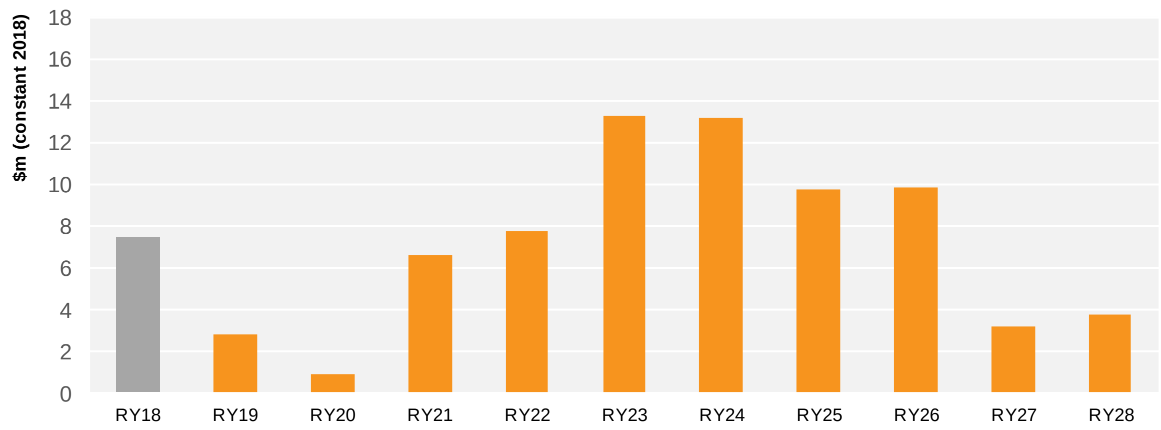
The planned replacement of our subtransmission cables has led to the relatively lumpy forecast Capex profile, with expenditure spikes relating to large individual projects. In particular we plan to replace the degrading gas-filled pressurised cable supplying the Dunedin CBD over the first half of the planning period.

A programme to replace all remaining cast iron potheads (discussed in Chapter 5) is evenly spread across the planning period, while work programmes encompassing renewal of poor condition distribution and LV cable ramp up during the period.

Zone Substations

Chapter 5 discussed the need to replace zone substation assets or, in limited cases, to rebuild the zone substation in its entirety. Key drivers for this expenditure are asset health, seismic requirements, and safety/environmental risk.

Figure 8.7: Zone Substations renewal Capex over the AMP period

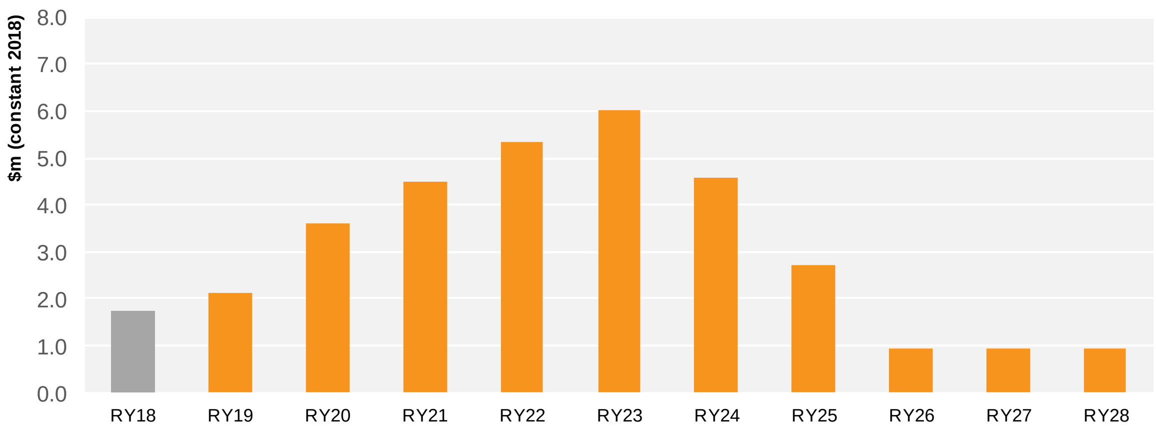


Like cables, most of our zone substation capital works are project-based (as opposed to a programme comprising many small but similar works). These works require significant detailed planning, and we intend to spend the next couple of years doing this work, before carrying out the large projects over the period from RY21 to RY26. Many of these projects involve replacement of one or more power transformers. We expect to replace about 30% of the fleet over the planning period. We are also planning to replace some of our oil-filled circuit breakers where deferral of operation-based maintenance makes this the most cost effective solution.

Distribution Switchgear

Capex on distribution switchgear such as fuses and pole mounted switches is often undertaken reactively, so our renewal forecasts are partially based on historical failures. However, we are also increasing proactive replacement of ground mounted switchgear with known type issues, and pole mounted switches with “do not operate” orders. The forecast for these replacements reflects ramping up both ground and pole mounted switchgear replacements to RY23, after which replacement volumes will decline. In the first half of the period we also plan to replace a number of reclosers. A programme to upgrade underground link boxes in Dunedin runs for the length of the planning period. Pole mounted fuse replacements will be carried out at a constant rate over the period, reflecting the reactive nature of this work.

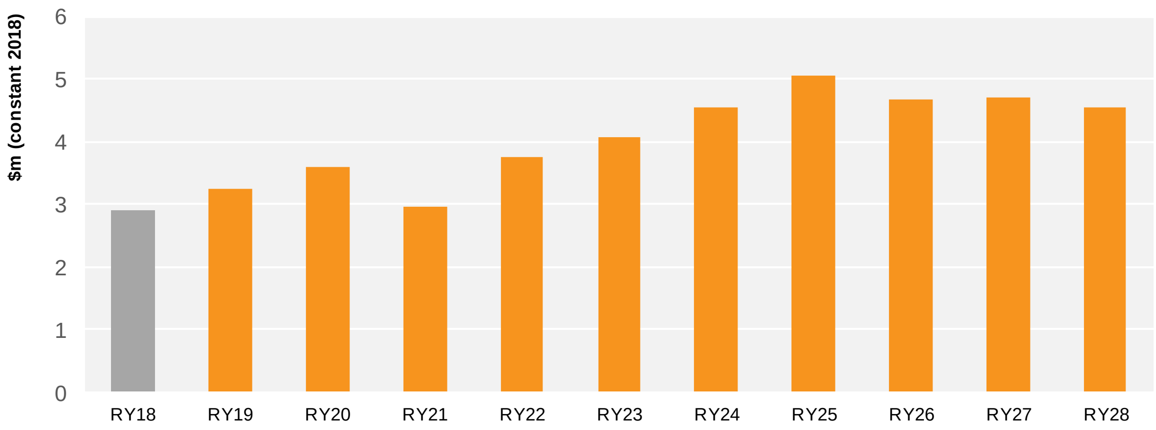
Figure 8.8: Distribution switchgear renewal Capex over the AMP period



Distribution Transformers

Our distribution transformer renewals forecast ramps up in the period to RY25, after which we will have reached ‘steady state’. The higher spend in RY20 relates to the purchase of a new mobile distribution substation. We are also planning to convert large pole mounted transformers to ground mount to reduce safety risk.

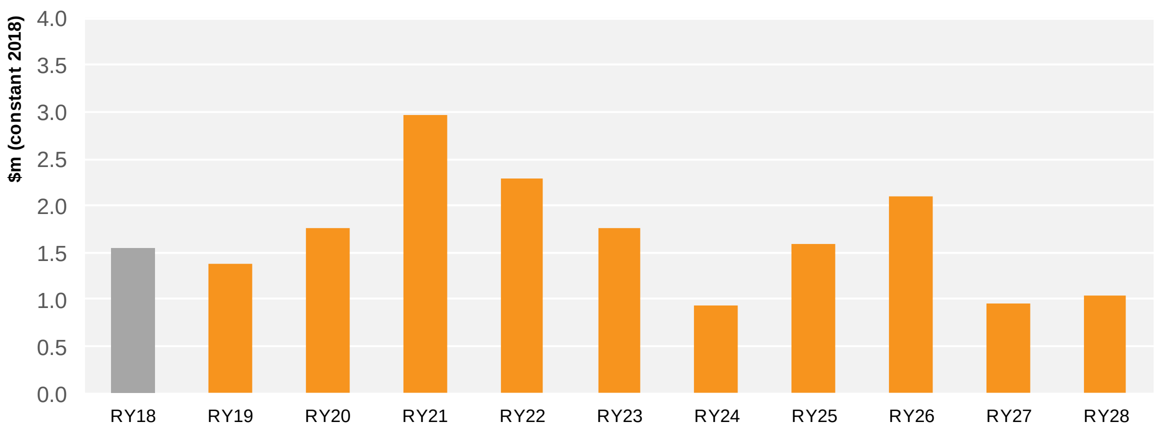
Figure 8.9: Distribution transformers renewal Capex over the AMP period



Secondary Systems

We are planning to replace a large number of old electromechanical relays and DC systems during the planning period, as discussed in Chapter 5. We align these replacements with zone substation projects, where practicable, which results in a relatively lumpy Capex profile for the period.

Figure 8.10: Secondary systems renewal Capex over the AMP period

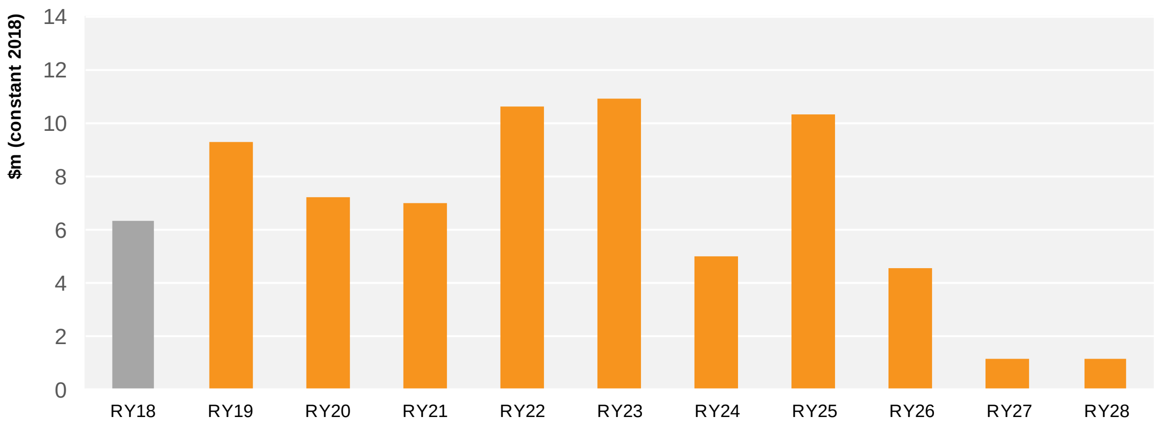


8.2.2. Growth and Security Capex

Growth and Security Capex includes three expenditure categories: major projects, distribution reinforcements, and LV reinforcements.

We plan to undertake over 30 growth and security Capex projects over the planning period. The majority of expenditure falls within the major projects Capex category, comprising works such as transformer upgrades, subtransmission capacity upgrades, and new substation builds.

Figure 8.11: Forecast Growth and Security Capex for the AMP period

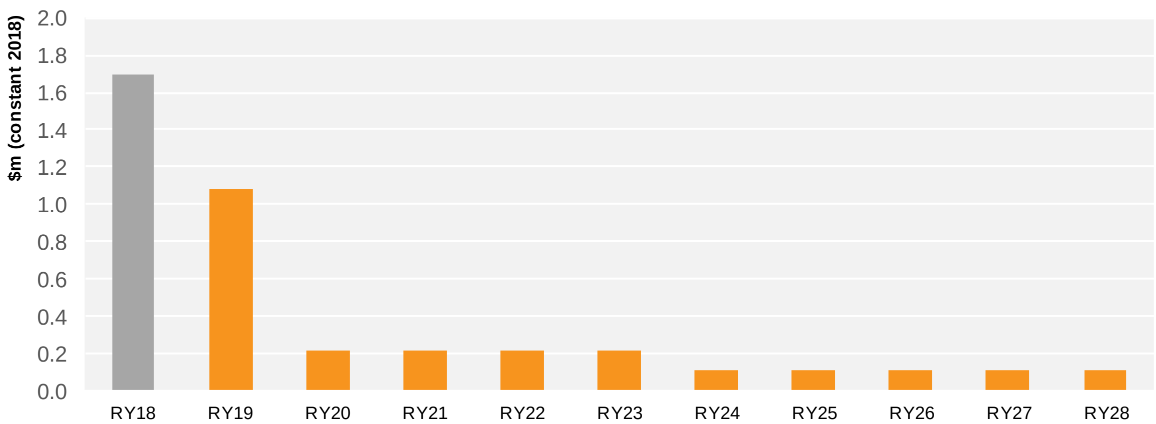


The forecast Capex profile is relatively lumpy, with expenditure spikes reflecting overlapping spend on two or more large projects. For example, forecast expenditure in 2023 combines single year projects to extend the new Frankton 33 kV feeder to Coronet Peak and construct several new mobile parking bays, with several large multi-year projects such as the installation of new transformers and switchgear at Arrowtown zone substation, for which some of the cost falls in the same year.

8.2.3. Reliability, Safety and Environment

Reliability, Safety and Environment Capex includes investments to improve safety or reliability (including power quality) or to reduce the environmental impact of our assets.

Figure 8.12: Forecast Reliability, Safety and Environment Capex for the AMP period

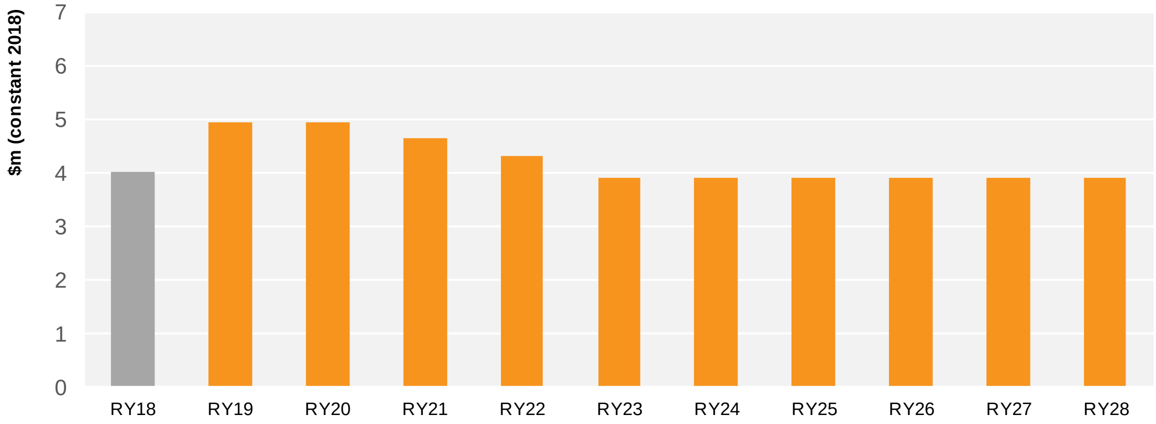


Capex in this category relates to installing new reclosers on problematic and unreliable feeders, procuring mobile generators and installing fault passage indicators. All these initiatives are targeting improved quality of supply.

8.2.4. Customer Connection Capex

Customer connection Capex is externally driven with short lead times which compromises our ability to accurately forecast medium-term requirements. We forecast connection numbers, customer connection Capex and capital contributions by trending historical data and including known large developments.

Figure 8.13: Forecast Customer Connections Capex (Net) for the AMP period



Our forecast assumes that we maintain our current capital contributions policy.

Historically, we have seen significant year-on-year variation in both customer connection Capex and capital contributions. Development activity in the Central Otago network in particular has been significant since (and including) 2015 as the property sector recovered from the global financial crisis.

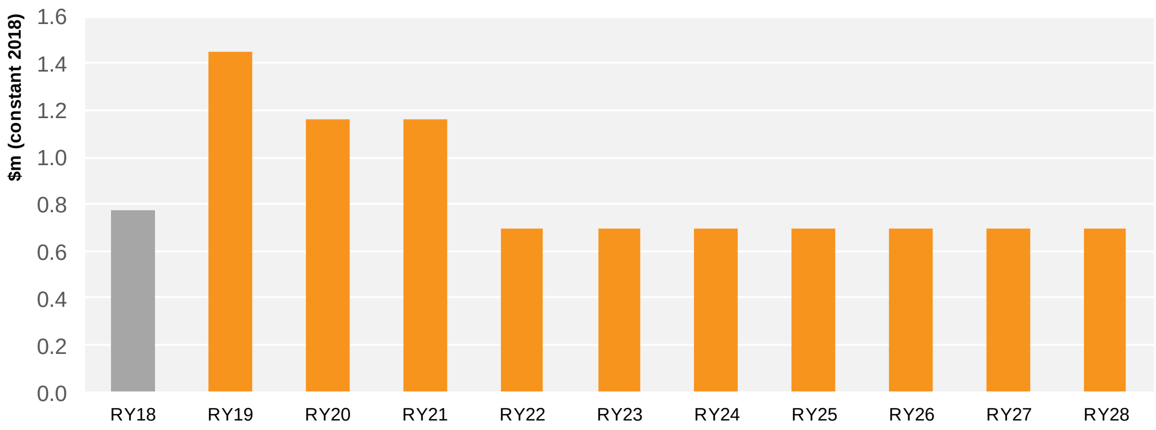
Although there is no certain evidence pointing to a downturn in development activity, economic forecasts by the Treasury indicate a slight decline in GDP to 2020, after which the picture is unclear. Accordingly we are forecasting that development activity will remain near existing levels until 2020 and then return to a longer-term average.

At the time of writing, we are not aware of any specific project that would be materially larger than normally encountered.

8.2.5. Asset Relocations

Asset relocations Capex is associated with moving our assets to enable other parties to undertake projects. Most commonly this relates to roading projects, but works may also be undertaken for other parties such as property developers. This is discussed in Chapter 5.

Figure 8.14: Forecast Asset Relocations Capex (Net) over the AMP period



We estimate relocation expenditure based on historic average expenditure, adjusted for known projects that are expected to occur within the next few years. Two major projects have been accounted for in our forecast:

- NZTA roading projects to relocate assets at the Kawarau Falls bridge in Queenstown
- undergrounding overhead circuits along SH6 to allow construction of additional traffic lanes.

These are expected to be completed in 2019 and 2021, respectively.

Our forecast capital cost of relocations is higher over the period to 2021 as the above projects are completed, with expenditure after that time in line with the longer-term average.

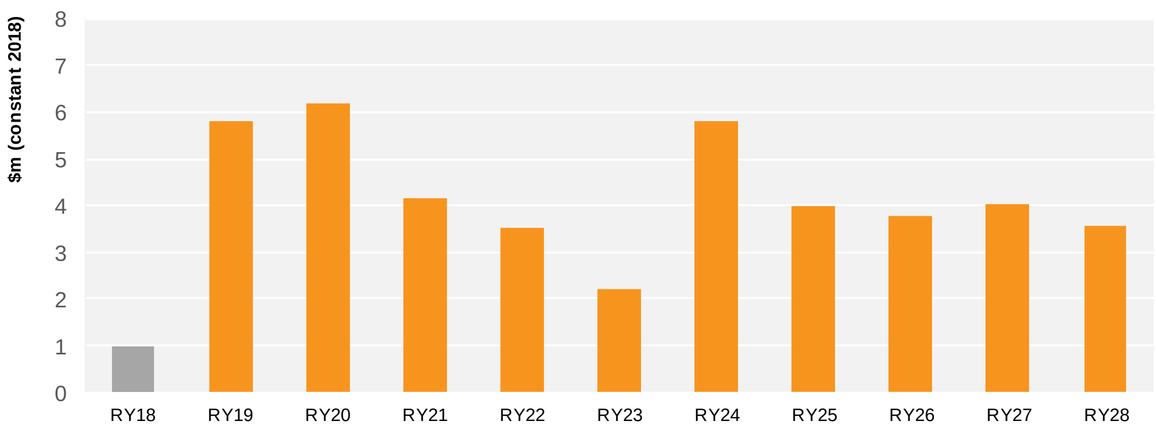
8.2.6. Non-network Capex

As discussed in Chapter 7, our non-network Capex is split into the following portfolios.

- corporate IT systems
- operational technology (OT) systems
- facilities and motor vehicles.

The combined expenditure in these portfolios is shown below.

Figure 8.15: Forecast Non-network Capex over the AMP period



Our main non-network investments in the planning period focus on establishing a standalone ICT capability. These investments are critical enablers of our development as a new business and improving of our asset management capability. We expect that these investments will support delivery of increased volumes of renewals Capex. An initial focus is on developing a purpose-built asset management system to consolidate current systems into a more effective platform.

Investments in the middle and later years of the period will include software and hardware lifecycle renewals and new capabilities to support the increased complexity and functionality of our network arising from emerging technology solutions. Given the rapidly changing nature of IT solutions the exact investments we make and their associated costs are less certain later in the period.

During the period we will invest in our facilities, including necessary refurbishments to our Cromwell and Dunedin offices. These investments will further establish the business as a standalone entity by removing any remaining shared facilities. They will also improve business resilience and facilitate changing operations processes. The changes will also free up space to create new meeting rooms and to safely accommodate increased staff numbers.

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Summary Table

The following table sets out our consolidated Capex forecast for the AMP period.

Table 8.1: Capex Summary

Constant 2018 NZ$ (000s)	RY19	RY20	RY21	RY22	RY23	RY24	RY25	RY26	RY27	RY28	Total
Renewals	**41,970**	**49,850**	**48,820**	**46,910**	**45,460**	**47,410**	**41,200**	**38,580**	**35,450**	**33,200**	**428,850**
- Support Structures	25,090	24,140	18,140	13,900	11,290	11,650	10,600	11,420	12,160	12,130	150,520
- Overhead Conductors	1,690	6,270	6,130	5,390	5,130	5,730	5,980	6,050	6,300	6,330	55,000
- Cables	5,690	9,600	7,580	8,450	3,960	6,830	5,490	3,640	7,250	4,510	63,000
- Distribution Transformers	3,250	3,590	2,970	3,760	4,080	4,540	5,050	4,680	4,720	4,550	41,190
- Distribution Switchgear	2,110	3,610	4,480	5,350	6,020	4,560	2,730	930	930	940	31,660
- Zone Substations	2,760	880	6,540	7,760	13,230	13,160	9,760	9,780	3,120	3,710	70,700
- Secondary Systems	1,380	1,760	2,970	2,290	1,750	940	1,580	2,090	960	1,040	16,760
Growth and Security	**9,250**	**7,180**	**6,970**	**10,620**	**10,910**	**5,000**	**10,310**	**4,490**	**1,100**	**1,100**	**66,930**
Consumer Connection (net of contributions)	**4,950**	**4,950**	**4,630**	**4,300**	**3,900**	**3,900**	**3,900**	**3,900**	**3,900**	**3,900**	**42,230**
Asset Relocations (net of contributions)	**1,450**	**1,160**	**1,160**	**700**	**700**	**700**	**700**	**700**	**700**	**700**	**8,670**
Reliability, Safety and Environment	**1,090**	**210**	**210**	**210**	**210**	**110**	**110**	**110**	**110**	**110**	**2,480**
Total Network CAPEX	**58,710**	**63,350**	**61,790**	**62,740**	**61,180**	**57,120**	**56,220**	**47,780**	**41,260**	**39,010**	**549,160**
Non-network CAPEX	**5,800**	**6,210**	**4,160**	**3,500**	**2,200**	**5,800**	**3,970**	**3,760**	**4,030**	**3,560**	**42,990**
Total CAPEX	**64,500**	**69,560**	**65,960**	**66,240**	**63,370**	**62,910**	**60,180**	**51,540**	**45,280**	**42,570**	**592,110**
Expected Contributions	**5,500**	**5,250**	**4,970**	**4,290**	**3,950**	**3,950**	**3,950**	**3,950**	**3,950**	**3,950**	**43,710**

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8.3. OPEX SUMMARY

Our Opex forecast includes our forecast expenditure in the following six portfolios. Further information on the forecasts can be found in Chapter 5. The first three of these are the Information Disclosure maintenance categories.[101]

- **Routine, Corrective Maintenance and Inspections:** includes our predictive and corrective maintenance categories discussed in Chapter 5.
- **Asset Replacement and Renewal**: category is not used in our day-to-day operations.
- **Service Interruptions and Emergencies**: is the equivalent to our reactive maintenance category and is discussed in Chapter 5.
- **Vegetation management**: relates to expenditure on tree trimming, inspection and liaison with tree owners, as discussed in Chapter 5.
- **Business Support**: includes the costs associated with support functions such as HR and Finance, as well as ICT-related Opex, as discussed in Chapter 7.
- **System Operations and Network Support:** is indirect network Opex where the primary driver is the management of the network, and includes expenditure relating to engineering staff, control centre and system operations, as discussed in Chapter 7.

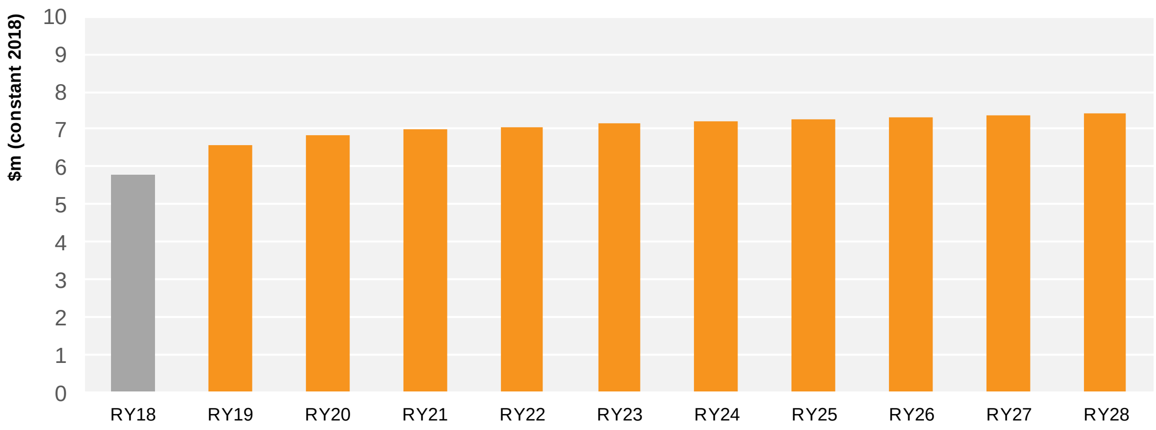
The following sections set out our planned Opex for each of the six portfolios. Appendix B sets out this expenditure using Information Disclosure categories.

8.3.1. Routine, Corrective Maintenance and Inspections (RCI)

We include preventive and corrective maintenance activities under the RCI category. Preventive maintenance is scheduled work, including servicing to maintain asset integrity, and inspections to compile condition information for subsequent analysis and planning. It is our most regular asset intervention and is a key input into our asset management system. Corrective maintenance restores assets that have aged, been damaged, or do not meet their intended functional condition. It is undertaken to ensure assets are safe and secure, and provide reliable service. A key aim is to address defects timely and systematically, before they give rise to failure.

101 Our approach to categorising maintenance activities (discussed in Chapter 5) differs from the Information Disclosure definitions.

Figure 8.16: Forecast RCI Opex for the AMP period



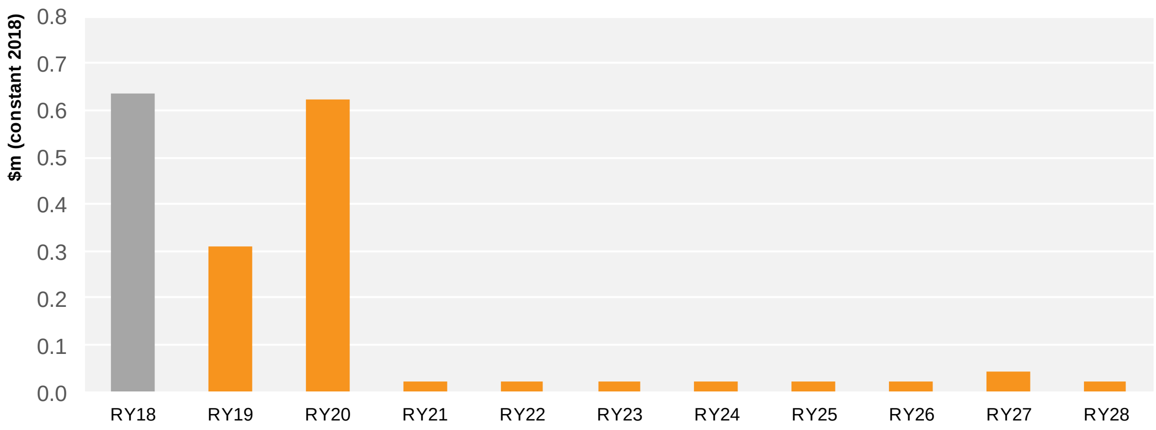
Increased RCI expenditure in coming years is due to the additional activities listed below. Some of these (e.g. accelerated pole inspections) will be temporary, leading to an eventual reduction in expenditure towards steady-state levels.

- **Pole inspections**: increased volumes of MPT testing to confirm overall fleet condition and defect numbers, prioritised by network criticality.
- **Circuit breaker maintenance:** some of our circuit breakers have not been maintained in line with the number of fault operations. We plan to catch up on this maintenance during the planning period.
- **Improved condition inspections**: we have started to introduce initiatives to improve our knowledge of asset condition and to pre-empt potential failures. Specific initiatives include forensic testing of overhead line components (conductor, insulators, terminations) to better understand overall fleet condition.
- **New inspection techniques**: recent technology advances allow improved asset inspection and condition assessment techniques. We plan to implement some of the most successful of these on our network, including drone-based inspections of pole-top assemblies and aerial photography of overhead lines. This will deliver a better understanding of asset health, risk and criticality, allow enhanced asset management, and will support improved investment targeting and overall lifecycle cost-effectiveness.
- **Defect numbers**: associated with improved inspection and condition assessments, we anticipate an initial increase in the number of defects requiring attention. We expect this will stabilise post RY21.

8.3.2. Asset Replacement and Renewal (ARR)

Asset replacement and renewal Opex, as a category, is not used in the day-to-day asset management of our network. Asset replacements and renewals treated as Opex are included in our corrective maintenance category.

Figure 8.17: Forecast ARR Opex over the AMP period

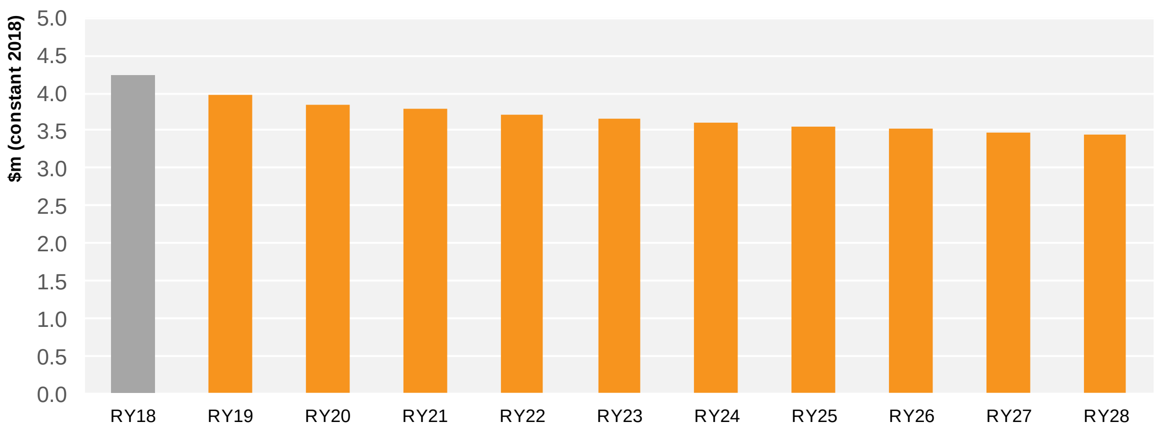


Following the completion of an asset signage and labelling project (to promote public safety), we expect there to be little expenditure attributed to this category over the AMP period.

8.3.3. Service Interruptions and Emergencies (SIE)

SIE involves interventions in response to network faults and other incidents. There is no advanced scheduling of this work other than ensuring that there are sufficient resources on standby to respond to network faults. Reactive maintenance is all about safely switching and restoring the supply to customers. It is especially prevalent during and after large events such as major storms.

Figure 8.18: Forecast SIE Opex for the AMP period



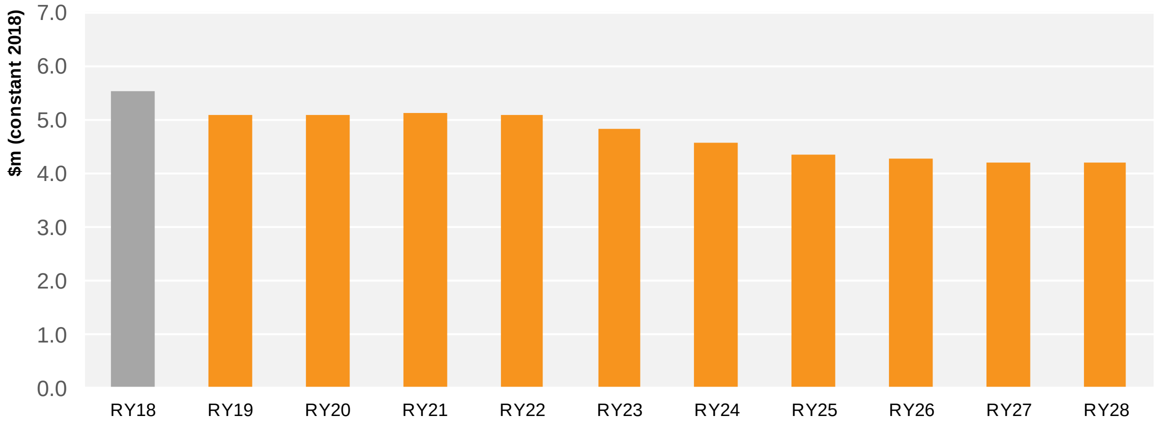
By its nature, reactive maintenance requirements cannot be accurately predicted for any particular year. Annual expenditure on reactive work is driven by the frequency and severity of network faults. Other than from poor asset condition, network faults are mainly influenced by external, often random, events.

No significant change in expenditure is proposed from current levels. Towards the end of the period we expect to achieve efficiencies (resulting in a reactive maintenance expenditure reduction) resulting from improved asset management practices and the significant asset renewal programme.

Vegetation management

Vegetation management is a key activity that enables our assets to perform as expected. We undertake vegetation management to keep trees clear of overhead lines and other assets. This is necessary to minimise vegetation related outages and comply with relevant obligations.

Figure 8.19: Forecast Vegetation Management Opex for the AMP period

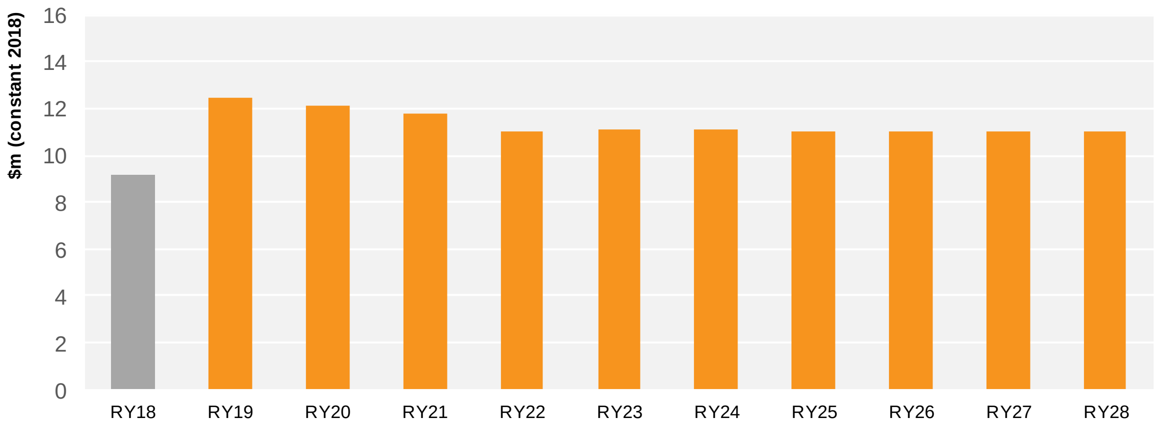


We are moving to a more proactive approach to managing vegetation, which has significant savings per tree site compared to a reactive approach. The overall number of tree sites to be inspected and trimmed will reduce as we move more of the network to a fully cyclical approach. We therefore expect the steady state expenditure level to reduce from current levels, while delivering an improved level of compliance and better safety and reliability outcomes.

8.3.4. Business Support

Business Support Opex includes spend that supports our day-to-day asset management activities. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs, legal, audit and governance fees, and insurance costs.

Figure 8.20: Forecast Business Support Opex for the AMP period



Our forecast expenditure is largely constant over the planning period. While we have an ongoing focus on improving our efficiency and are confident that improvements can be made, we also recognise that there will be additional demands and requirements that may offset these savings.

ICT-related Opex has increased from historical levels. The increase in these costs is required to support newly rolled out ICT systems as they are put into production. However, these new systems provide improved functionality which will allow us to better manage our expenditure and future costs. This reflects the modernisation and standardisation work which will continue through the planning period, including ongoing investment in server virtualisation technologies, and leveraging cloud services for test and development environments and other non-critical business functions. We are increasing our focus on capacity planning, licensing management, and the introduction of open source technologies in selected areas.

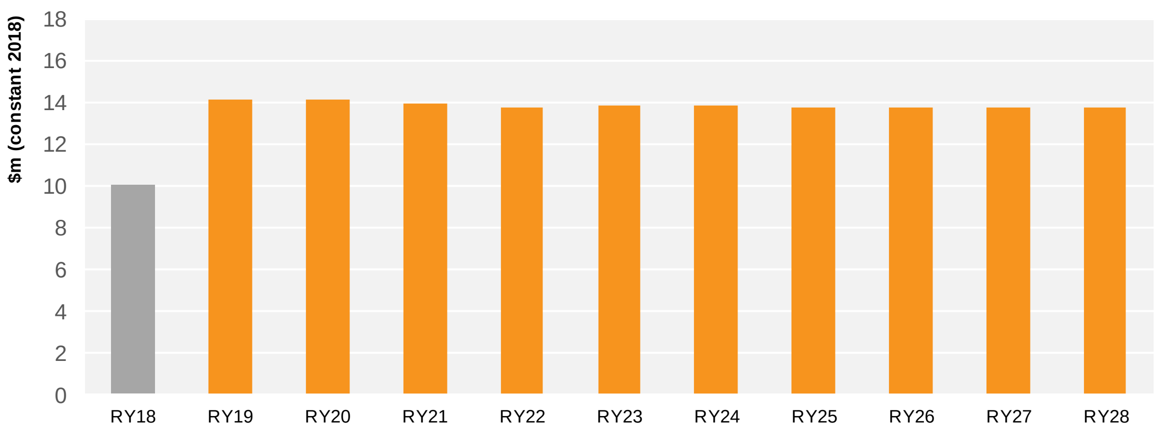
A further increase in spend results from moving to outsourced data centres. The service costs of outsourced data centres reduce Capex by avoiding the need to rebuild or relocate our existing centres, while also providing improved security and reducing risk.

We expect that Business Support Opex will be broadly constant from the end of RY21 despite upward cost pressures.

8.3.5. System Operations and Network Support (SONS)

SONS is Opex where the primary driver is the management of the network and includes expenditure relating to control centre and office-based system operations.

Figure 8.21: Forecast SONS Opex for the AMP period



Our SONS forecast reflects the need to continue developing our people and their capabilities. It includes increased engineering capacity to process additional work volumes, and to enable us to accommodate new solutions. Operational changes and improvements are required to achieve the maintenance strategy, improve asset management, and to support increased renewals and maintenance work.

- **Capability increases**: our goal of good industry practice asset management (as we plan to demonstrate by achieving ISO 55000 certification in 2023), evolving our maintenance strategy, and responding to changing customer needs requires expanding our internal capabilities and skills

- **Capacity increases**: efficiently delivering increased capital and maintenance works requires additional internal resources for planning, design, project and contract management
- **Expenditure optimisation**: we need to ensure we can effectively account for a range of factors – lifecycle cost, asset risks, safety and environment, customer preferences, compliance and commercial implications – in our long-term investment planning. We will invest in our skills in areas underpinning this analysis including quantified risk assessment, lifecycle costing studies, and cost-benefit analysis
- **Improved asset information**: improving data quality, information management and analysis capability is necessary to underpin asset management and operational improvements.

8.3.6. Summary Table

The following table sets out our consolidated Opex forecast for the AMP period.

Table 8.2: Opex Summary

Constant 2018 NZ$ (000s)	RY19	RY20	RY21	RY22	RY23	RY24	RY25	RY26	RY27	RY28	Total
Network OPEX	**15,940**	**16,370**	**15,890**	**15,870**	**15,660**	**15,410**	**15,190**	**15,140**	**15,080**	**15,070**	**155,620**
- Routine, Corrective Maintenance and Inspections	6,580	6,830	6,970	7,070	7,150	7,220	7,270	7,320	7,360	7,400	71,170
- System Interruptions and Emergencies	3,970	3,850	3,790	3,710	3,650	3,610	3,550	3,510	3,480	3,460	36,580
- Asset Replacement and Renewal	310	620	20	20	20	20	20	20	40	20	1,110
- Vegetation	5,070	5,070	5,110	5,070	4,830	4,560	4,350	4,280	4,200	4,200	46,740
Non-network OPEX	**26,530**	**26,250**	**25,760**	**24,840**	**24,940**	**24,970**	**24,830**	**24,830**	**24,830**	**24,830**	**252,610**
Total OPEX	**42,460**	**42,620**	**41,650**	**40,710**	**40,600**	**40,380**	**40,030**	**39,970**	**39,910**	**39,900**	**408,230**

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8.4. COST ESTIMATION

In general, our expenditure forecasts are developed using predictive forecasting techniques that estimate necessary work volumes and apply associated unit rates to them. This bottom-up approach uses cost estimates and unit rates that are linked to outturn costs (where available).

8.4.1. Overview

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 Estimates (Capex and Opex)**: used for smaller, high-volume works that are reasonably routine and uniform. These are generally related to scheduled repairs, small renewals, and scheduled maintenance
- **Base-Step-Trend (Capex and Opex)**: is mainly used for forecasting reactive maintenance and indirect network Opex. It is also used for non-network Opex and some trend-based Capex forecasts.

These estimate types are discussed below.

8.4.2. Tailored Estimates

This approach involves developing cost estimates based on project scopes. Project scopes are determined from desktop reviews of asset information such as aerial photographs, site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities, for example, building extensions and cabling.

Activity costs are based on historical costs, service provider rates, quotes, and external reviews. Material costs are determined with reference to supply contracts and historical costs. Installation costs are informed by similar previous projects and updated with current prices or quotes.

For investment in large non-network systems, we have based our forecasts on a combination of tender responses and desktop estimates for those later in the period. These desktop estimates are mainly informed by historical tenders and discussions with vendors.

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.

8.4.3. Volumetric Estimates

Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. The key determinant of accurate cost estimates for volumetric projects is the use of historical costs from completed equivalent projects. This feedback is used 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.

Using this approach we consider that our volumetric works will have appropriate estimates, 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.

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.

8.4.4. Trending

We have used a trend-based approach to forecast part of our expenditure. The approach is used by many utilities for forecasting recurring expenditure. This is mainly used for forecasting reactive maintenance and certain trend-based Capex forecasts such as asset relocations.

The approach starts with selecting a representative 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.

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.

8.4.5. Inputs and Assumptions

The following inputs and assumptions have informed our overall forecasting approaches.

Demand Forecasts

Historical relationships between proxy drivers (such as GDP) and demand load growth continue to apply in the short term. We expect our demand forecasting approach (discussed in Chapter 6) to evolve over the next few years. In the medium term the increasing adoption of new technologies may alter these underlying relationships and we will monitor these trends carefully. Our investment planning approach is designed to ensure that we do not invest in new capacity until we are sure it is required, which moderates the risk of over investment.

We will refine our approach to demand forecasting as part of our AMDP and will adapt our approach as our understanding evolves.

Embedded Generation

Embedded generation will not have a material impact on network investment in the planning period. We have assumed that the installation of PV and energy storage will not materially affect peak load growth or related investment requirements over the planning period (refer to Chapter 3). The requirement for network reinforcement, which is largely driven by peak load, is therefore not anticipated to increase noticeably as a result of embedded generation.

Historical Unit Rates

Historical unit rates for volumetric works reflect likely future scopes and risks, at an aggregate or portfolio level. While we continue to target efficiency in all aspects of our work delivery, our experience has shown that increased efficiency tends to be offset by enhanced safety-related costs (such as traffic management) and increased costs associated with accessing the road corridor and private land.

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APPENDICES

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A. GLOSSARY

ACRONYM	MEANING
ABS	Air break switch
ACSR	Aluminum conductor steel reinforced (cable)
AHI	Asset Health Indices
ADMD	After diversity maximum demand
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
CB	Circuit breaker
CAIDI	Consumer average interruption duration index
CAPEX	Capital expenditure
CODC	Central Otago District Council
CPP	Customised price-quality path
DC	Direct current
DCC	Dunedin City Council
DGA	Dissolved gas analysis
DSM	Demand side management
EV	Electric vehicle
GIS	Geospatial Information System
GWh	Gigawatt hour
GXP	Grid exit point
HILP	High impact low probability (events)
HV	High voltage
HWB	Halfway Bush
ICP	Installation control point
IEDs	Intelligent electronic devices
km	Kilometer
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LV	Low voltage
MPL	Maximum Practical Life
MVA	Mega volt-ampere

ACRONYM	MEANING
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
NZTA	New Zealand Transport Agency
NBS	New Building Standard
ORC	Otago Regional Council
PILC	Paper insulated lead cable
PV	Photo voltaic
QLDC	Queenstown-Lakes District Council
RC	Replacement cost
RMU	Ring Main Unit (distribution switchgear)
RSE	Reliability, Safety and Environment (capex)
RTU	Remote Terminal Unit
SAIDI	System average interruption duration index (minutes)
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition System
SF_6	Sulphur hexafluoride
SWER	Single wire earth return.
V	Volt
VoLL	Value of Lost Load
XLPE	Cross linked polyethylene cable

B. INFORMATION DISCLOSURE SCHEDULES

This appendix includes the following Information Disclosure schedules:

- **Schedule 11a**: report on forecast Capital Expenditure
- **Schedule 11b**: report on forecast Operational Expenditure
- **Schedule 12a:** report on asset condition
- **Schedule 12b:** report on forecast capacity
- **Schedule 12c:** report on forecast network demand
- **Schedule 12d:** report on forecast interruptions and duration
- **Schedule 13**: report on asset management maturity
- **Schedule 14a**: commentary on differences between forecast Capex (schedule 11a) and Opex (schedule 11b) in nominal and constant prices

Note: changes to Schedule 12A

For our 2018 AMP we have changed our method for populating Schedule 12A – Asset Condition. We have used Asset Health Indices (AHI) to populate the majority of asset classes in the schedule. Our five asset health scores (H1-H5) are mapped to condition grades 1-4. Our AHI framework is discussed in more detail in Chapter 5. These changes better align our asset condition schedule to our renewal programmes.

Schedule 11a: report on forecast Capital Expenditure

	Company Name	**Aurora Energy Limited**
	AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref														
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	8,494	9,462	9,526	8,937	8,412	7,715	7,808	7,903	8,077	8,255	8,437
11		System growth	6,343	9,358	7,073	6,990	10,858	11,424	5,198	10,677	4,807	1,219	1,261
12		Asset replacement and renewal	50,767	42,863	51,038	50,090	48,543	47,253	49,877	44,072	42,421	40,063	38,462
13		Asset relocations	1,037	2,769	2,230	2,243	1,366	1,384	1,402	1,420	1,452	1,484	1,516
14		Reliability, safety and environment:											
15		Quality of supply	-	1,069	211	214	217	219	114	116	119	122	125
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,700	-	-	-	-	-	-	-	-	-	-
18		**Total reliability, safety and environment**	1,700	1,069	211	214	217	219	114	116	119	122	125
19		**Expenditure on network assets**	68,341	65,523	70,077	68,474	69,396	67,995	64,399	64,189	56,875	51,143	49,802
20		Expenditure on non-network assets	956	5,961	6,574	4,526	3,899	2,511	6,779	4,759	4,619	5,065	4,592
21		**Expenditure on assets**	69,297	71,483	76,651	73,001	73,295	70,505	71,177	68,948	61,494	56,208	54,394
22													
23	*plus*	Cost of financing	-	1,364	1,360	1,240	711	136					
24	*less*	Value of capital contributions	4,751	5,653	5,434	5,165	4,516	4,202	4,252	4,304	4,399	4,496	4,595
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	64,546	67,194	72,577	69,075	69,489	66,440	66,925	64,644	57,096	51,712	49,799
28													
29		Assets commissioned	50,335	96,115	75,591	70,616	68,412	75,975	66,333	64,496	58,804	45,279	50,502
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
32			**$000 (in constant prices)**										
33		Consumer connection	8,494	9,200	9,200	8,600	8,000	7,250	7,250	7,250	7,250	7,250	7,250
34		System growth	6,343	9,250	7,182	6,974	10,619	10,910	5,002	10,307	4,491	1,100	1,100
35		Asset replacement and renewal	50,767	41,969	49,850	48,825	46,911	45,458	47,411	41,198	38,577	35,450	33,202
36		Asset relocations	1,037	2,693	2,154	2,154	1,293	1,293	1,293	1,293	1,293	1,293	1,293
37		Reliability, safety and environment:											
38		Quality of supply	-	1,085	210	210	210	210	110	110	110	110	110
39		Legislative and regulatory	-	-	-	-	-	-		-	-	-	-
40		Other reliability, safety and environment	1,700	-	-	-	-	-	-	-	-	-	-
41		**Total reliability, safety and environment**	1,700	1,085	210	210	210	210	110	110	110	110	110
42		**Expenditure on network assets**	68,341	64,198	68,597	66,763	67,033	65,120	61,066	60,158	51,721	45,203	42,955
43		Expenditure on non-network assets	956	5,801	6,210	4,163	3,500	2,200	5,798	3,973	3,764	4,028	3,565
44		**Expenditure on assets**	69,297	69,998	74,807	70,926	70,533	67,320	66,863	64,130	55,484	49,231	46,519
45													
46		**Subcomponents of expenditure on assets (where known)**											
47		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49		Research and development	-	-	-	-	-	-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	262	326	337	412	465	558	653	827	1,005	1,187
System growth		-	108	(110)	17	239	514	195	371	316	119	161
Asset replacement and renewal		-	894	1,187	1,265	1,632	1,795	2,466	2,875	3,844	4,614	5,260
Asset relocations		-	77	76	89	73	91	109	128	159	191	224
Reliability, safety and environment:												
Quality of supply		-	(16)	1	4	6	9	4	6	9	12	15
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment		-	(16)	1	4	6	9	4	6	9	12	15
Expenditure on network assets		-	1,325	1,480	1,711	2,363	2,874	3,333	4,032	5,155	5,941	6,847
Expenditure on non-network assets		-	160	364	363	399	311	981	786	855	1,037	1,027
Expenditure on assets		-	1,485	1,844	2,075	2,762	3,185	4,314	4,818	6,010	6,977	7,875

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23

11a(ii): Consumer Connection

*Consumer types defined by EDB**		**$000 (in constant prices)**					
All consumers		8,494	9,200	9,200	8,600	8,000	7,250
**include additional rows if needed*							
Consumer connection expenditure		8,494	9,200	9,200	8,600	8,000	7,250
Capital contributions funding consumer connection	*less*	4,483	4,252	4,252	3,975	3,698	3,351
Consumer connection less capital contributions		4,011	4,948	4,948	4,625	4,302	3,899

11a(iii): System Growth

Subtransmission		224	1,339	674	1,865	5,148	6,500
Zone substations		5	2,987	3,509	3,616	3,020	1,454
Distribution and LV lines		41	293	50	50	100	100
Distribution and LV cables		391	2,935	1,465	317	443	329
Distribution substations and transformers		150	976	976	811	1,497	1,288
Distribution switchgear		352	260	362	165	326	538
Other network assets		5,180	460	147	151	84	701
System growth expenditure		6,343	9,250	7,182	6,974	10,619	10,910
Capital contributions funding system growth	*less*						
System growth less capital contributions		6,343	9,250	7,182	6,974	10,619	10,910

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23

11a(iv): Asset Replacement and Renewal

		$000 (in constant prices)					
Subtransmission		3,872	8,277	16,777	14,183	8,416	3,177
Zone substations		7,470	2,758	876	6,540	7,764	13,227
Distribution and LV lines		32,020	23,427	21,880	15,912	17,412	15,049
Distribution and LV cables		1,204	768	1,352	1,765	1,918	2,149
Distribution substations and transformers		2,896	3,252	3,593	2,973	3,758	4,078
Distribution switchgear		1,755	2,111	3,613	4,484	5,351	6,023
Other network assets		1,550	1,376	1,760	2,967	2,292	1,754
Asset replacement and renewal expenditure		50,767	41,969	49,850	48,825	46,911	45,458
Capital contributions funding asset replacement and renewal	*less*						
Asset replacement and renewal less capital contributions		50,767	41,969	49,850	48,825	46,911	45,458

11a(v):Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other project or programmes - asset relocations		1,037	2,693	2,154	2,154	1,293	1,293
Asset relocations expenditure		1,037	2,693	2,154	2,154	1,293	1,293
less Capital contributions funding asset relocations		268	1,245	996	996	597	597
Asset relocations less capital contributions		769	1,448	1,159	1,159	695	695

11a(vi):Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - quality of supply		-	1,085	210	210	210	210
Quality of supply expenditure		-	1,085	210	210	210	210
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		-	1,085	210	210	210	210

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - legislative and regulatory							
Legislative and regulatory expenditure		-	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		-	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23

11a(viii): Other Reliability, Safety and Environment

Project or programme*	$000 (in constant prices)					
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment	1,700	-	-	-	-	-
Other reliability, safety and environment expenditure	1,700	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	1,700	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	$000 (in constant prices)					
*include additional rows if needed						
All other projects or programmes - routine expenditure	956	5,801	6,210	4,163	3,500	2,200
Routine expenditure	956	5,801	6,210	4,163	3,500	2,200

Atypical expenditure

Project or programme*						
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	956	5,801	6,210	4,163	3,500	2,200

Schedule 11b: report on forecast Operational Expenditure

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,251	4,083	4,076	4,120	4,131	4,171	4,220	4,251	4,312	4,379	4,452
11	Vegetation management	5,517	5,210	5,367	5,558	5,647	5,511	5,332	5,213	5,258	5,276	5,405
12	Routine and corrective maintenance and inspection	5,783	6,765	7,225	7,579	7,879	8,163	8,439	8,712	8,984	9,257	9,533
13	Asset replacement and renewal	636	319	658	23	24	25	25	26	26	51	28
14	**Network Opex**	16,187	16,376	17,326	17,280	17,681	17,870	18,016	18,201	18,580	18,963	19,417
15	System operations and network support	9,985	14,392	14,837	14,988	15,153	15,561	15,939	16,229	16,607	16,994	17,390
16	Business support	9,172	12,720	12,674	12,698	12,165	12,515	12,821	13,038	13,342	13,654	13,972
17	**Non-network opex**	19,157	27,112	27,512	27,686	27,318	28,076	28,760	29,267	29,949	30,648	31,362
18	**Operational expenditure**	35,344	43,488	44,837	44,966	44,999	45,946	46,776	47,469	48,530	49,611	50,779
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,251	3,973	3,850	3,789	3,708	3,655	3,609	3,549	3,514	3,483	3,456
23	Vegetation management	5,517	5,070	5,070	5,112	5,070	4,829	4,561	4,352	4,284	4,196	4,196
24	Routine and corrective maintenance and inspection	5,783	6,583	6,825	6,970	7,073	7,152	7,218	7,273	7,320	7,362	7,400
25	Asset replacement and renewal	636	311	622	22	22	22	22	22	22	41	22
26	**Network Opex**	16,187	15,937	16,367	15,893	15,872	15,658	15,409	15,195	15,140	15,082	15,073
27	System operations and network support	9,985	14,081	14,157	13,944	13,776	13,825	13,838	13,769	13,769	13,769	13,769
28	Business support	9,172	12,445	12,093	11,813	11,060	11,119	11,131	11,062	11,062	11,062	11,062
29	**Non-network opex**	19,157	26,527	26,250	25,758	24,836	24,944	24,969	24,831	24,831	24,831	24,831
30	**Operational expenditure**	35,344	42,463	42,617	41,650	40,708	40,602	40,378	40,026	39,971	39,913	39,904
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	110	226	331	423	516	611	702	798	896	996
43	Vegetation management	-	140	297	446	578	682	772	861	974	1,080	1,209
44	Routine and corrective maintenance and inspection	-	182	400	609	806	1,010	1,221	1,439	1,664	1,895	2,133
45	Asset replacement and renewal	-	9	36	2	2	3	4	4	5	10	6
46	**Network Opex**	-	440	959	1,388	1,809	2,212	2,607	3,007	3,441	3,881	4,344
47	System operations and network support	-	311	680	1,044	1,377	1,736	2,101	2,460	2,838	3,225	3,622
48	Business support	-	275	581	885	1,105	1,396	1,690	1,976	2,280	2,591	2,910
49	**Non-network opex**	-	585	1,261	1,929	2,482	3,132	3,790	4,436	5,118	5,817	6,531
50	**Operational expenditure**	-	1,025	2,220	3,316	4,290	5,344	6,398	7,443	8,559	9,698	10,875

Schedule 12a: report on asset condition

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref											
7					**Asset condition at start of planning period (percentage of units by grade)**						
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	0.56%	0.18%	1.11%	98.15%	-	3	1.00%
11	All	Overhead Line	Wood poles	No.	12.91%	6.74%	17.44%	62.92%	-	3	27.00%
12	All	Overhead Line	Other pole types	No.						N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	19.05%	0.43%	5.25%	75.26%	0.01%	2	23.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km						N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	100.00%		3	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	100.00%		3	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	47.44%	45.11%	7.46%		3	63.00%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	100.00%			3	62.00%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km						N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km						N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km						N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km						N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km						N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	3.33%	-	16.67%	80.00%		2	17.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%		2	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	47.73%	-	9.09%	43.18%		2	68.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.						N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	33.73%	0.40%	9.24%	56.63%		2	14.00%
30	HV	Zone substation switchgear	33kV RMU	No.						N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.						N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	100.00%		2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	33.71%	6.18%	12.36%	47.75%		2	16.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	
35											

					Asset condition at start of planning period (percentage of units by grade)						
36											
37	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	26.98%	3.17%	19.05%	50.79%		2	10.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	18.23%	1.92%	6.92%	72.85%	0.08%	2	11.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km						N/A	
42	HV	Distribution Line	SWER conductor	km	49.50%	-	6.96%	43.54%	-	2	50.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.01%	0.92%	98.98%	0.10%	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.04%	0.26%	16.04%	83.66%	-	2	2.00%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	100.00%	-	-	-	2	100.00%
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	100.00%		2	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.						N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7.19%	2.51%	9.62%	80.67%		2	13.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	6.76%	-	1.35%	91.89%		2	7.00%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	21.16%	2.89%	2.03%	73.93%		2	26.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	10.31%	3.49%	16.08%	70.13%		2	18.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.07%	0.17%	0.93%	98.84%		3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	7.69%	-	92.31%		2	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.						N/A	
55	LV	LV Line	LV OH Conductor	km	6.97%	1.77%	3.89%	77.41%	9.96%	2	10.00%
56	LV	LV Cable	LV UG Cable	km	0.83%	0.60%	3.16%	95.42%		2	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	6.64%	2.10%	14.26%	76.99%		2	11.00%
58	LV	Connections	OH/UG consumer service connections	No.	0.73%	1.64%	10.92%	48.27%	38.44%	2	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	22.37%	13.70%	31.50%	32.43%		2	52.89%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	20.00%	40.00%	20.00%	20.00%		2	100.00%
61	All	Capacitor Banks	Capacitors including controls	No.				100.00%		2	-
62	All	Load Control	Centralised plant	Lot	-	43.48%	56.52%	-		3	73.92%
63	All	Load Control	Relays	No.	15.57%	6.63%	38.27%	39.53%		2	
64	All	Civils	Cable Tunnels	km						N/A	

Schedule 12b: report on forecast capacity

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Alexandra	11	15	N-1	-	74%	15	81%	No constraint within +5 years	
10	Anderson's Bay	15	18	N-1	5	83%	18	85%	No constraint within +5 years	
11	Arrowtown	9	6	N-1	2	142%	12	88%	No constraint within +5 years	A third transformer will be added to Arrowtown in RY19 to raise the firm capacity to 12MVA
12	Commonage	12	17	N-1	6	72%	17	79%	No constraint within +5 years	
13	Corstorphine	13	23	N-1	6	56%	23	57%	No constraint within +5 years	
14	Cromwell	11	8	N-1	-	149%	24	51%	No constraint within +5 years	The Cromwell transformers will be upgraded to 24MVA in RY20
15	East Taieri	16	24	N-1	4	67%	24	68%	No constraint within +5 years	
16	Frankton	15	15	N-1	6	97%	15	111%	No constraint within +5 years	We will monitor growth at Frankton and consider and upgrade to the smaller 15MVA transformer at this site but intend to manage growth during the AMP period by transfers to Commonage zone substation.
17	Fernhill	7	10	N-1	4	67%	10	74%	No constraint within +5 years	
18	Green Island	13	18	N-1	6	74%	18	76%	No constraint within +5 years	
19	Halfway Bush	15	24	N-1	6	63%	24	82%	Other	The capacity at Halfway Bush is currently constrained to 18MVA by the 6.6kV switchboard which has a planned replacement in RY22
20	Kaikorai Val.	10	23	N-1	4	44%	23	47%	Other	
21	Mosgiel	7	12	N-1	3	58%	12	61%	No constraint within +5 years	
22	Neville St	12	18	N-1	6	64%	24	53%	No constraint within +5 years	To be replaced with Carisbrook substation which will have a firm capacity of 24MVA
23	North City	18	28	N-1	6	65%	28	68%	No constraint within +5 years	The North City forecast excludes the new hospital connection. Similarly the cost to relocate North City zone substation (if required) has not been included our financial forecasts
24	North East Val.	11	18	N-1	4	60%	18	62%	Other	
25	Port Chalmers	7	10	N-1	3	65%	10	70%	No constraint within +5 years	
26	Queenstown	14	20	N-1	6	70%	20	81%	No constraint within +5 years	
27	Smith St	14	18	N-1	6	78%	18	85%	No constraint within +5 years	
28	South City	15	18	N-1	6	85%	18	89%	No constraint within +5 years	
29	St Kilda	15	23	N-1	6	64%	23	67%	No constraint within +5 years	
30	Wanaka	20	24	N-1	1	83%	24	97%	No constraint within +5 years	It is proposed to relieve the Wanaka constraint by the installation of transformer capacity at Riverbank in RY25
31	Ward St	11	23	N-1	6	47%	23	53%	Other	
32	Willowbank	13	18	N-1	4	70%	18	71%	No constraint within +5 years	
33	Berwick	1	4	N	4	39%	4	42%	No constraint within +5 years	
34	Cardrona	4	6	N	1	68%	5	180%	Transformer	Load growth subject to Cardrona expansion going ahead. This AMP makes no provision for a Cardrona upgrade at this stage
35	Clyde/Earnscleugh	3	5	N	-	65%	5	90%	No constraint within +5 years	
36	Coronet Peak	5	6	N	2	88%	6	90%	No constraint within +5 years	
37	Dalefield	2	4	N	1	67%	4	94%	No constraint within +5 years	
38	Earnscleugh	-	2	N	-	-	2	-	No constraint within +5 years	Earnscleugh is used as a back up to Clyde Earnscleugh
39	Ettrick	2	4	N	2	51%	4	56%	No constraint within +5 years	
40	Lindis Crossing	6	8	N	4	79%	8	28%	No constraint within +5 years	
41	Camphill	5	7	N	2	82%	7	90%	Transformer	Further irrigation load growth at Camphill is uncertain - at this stage, no upgrade project has been included in the AMP period
42	Omakau	3	3	N	2	93%	3	100%	No constraint within +5 years	Subject to further irrigation growth, it is proposed to upgrade and shift Omakau substation in RY25
43	Lauder Flat	1	4	N	1	18%	4	53%	No constraint within +5 years	
44	Outram	3	6	N	2	47%	6	50%	No constraint within +5 years	
45	Queensberry	3	4	N	2	70%	4	95%	No constraint within +5 years	
46	Remarkables	2	4	N	-	67%	4	197%	Transformer	A capacity upgrade at Remarkables is subject to continued supply of the Remarkables ski field - at this stage we have made no allowance for the upgrade
47	Roxburgh	2	6	N	1	30%	6	42%	No constraint within +5 years	

46 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c: report on forecast network demand

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

7 12c(i): Consumer Connections

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
11	*Consumer types defined by EDB**						
12	Residential	1,208	951	858	859	865	856
13	Load Group 0	(5)	(11)	(10)	(10)	(10)	(10)
14	Load Group 0A	21	70	63	63	63	63
15	Load Group 1A	15	18	16	16	17	16
15a	Load Group 1	64	46	41	41	41	41
15b	Load Group 2	144	95	86	86	86	86
15c	Load Group 3	-	5	4	4	4	4
15d	Load Group 3A	8	5	5	5	5	5
15e	Load Group 4	7	5	4	4	4	4
15f	Load Group 5	-	-	-	-	-	-
16	Street Lighting & DUML	-	0	0	0	0	0
17	**Connections total**	1,462	1,184	1,068	1,069	1,077	1,066
18	**include additional rows if needed*						

sch ref	Distributed generation	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
19	**Distributed generation**						
20	Number of connections	881	1,065	1,243	1,420	1,597	1,774
21	Capacity of distributed generation installed in year (MVA)	1	9	1	1	1	1

22 12c(ii) System Demand

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
25		GXP demand	222	237	240	242	245	248
26	*plus*	Distributed generation output at HV and above	77	67	68	69	70	70
27		**Maximum coincident system demand**	300	304	308	311	315	318
28	*less*	Net transfers to (from) other EDBs at HV and above	(0)	(0)	(0)	(0)	(0)	(0)
29		**Demand on system for supply to consumers' connection points**	300	304	308	311	315	318

sch ref		Electricity volumes carried (GWh)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	1,121	1,132	1,146	1,160	1,173	1,187
32	*less*	Electricity exports to GXPs	37	78	79	79	80	80
33	*plus*	Electricity supplied from distributed generation	316	370	375	379	383	387
34	*less*	Net electricity supplied to (from) other EDBs	(1)	(1)	(1)	(1)	(1)	(1)
35		**Electricity entering system for supply to ICPs**	1,400	1,425	1,443	1,460	1,477	1,495
36	*less*	Total energy delivered to ICPs	1,308	1,337	1,354	1,369	1,385	1,402
37		**Losses**	92	88	89	91	92	93
38								
39		**Load factor**	53%	53%	53%	54%	54%	54%
40		**Loss ratio**	6.6%	6.2%	6.2%	6.2%	6.2%	6.2%

Schedule 12d: Report on forecast interruptions and duration

Company Name	**Aurora Energy Limited**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Network / Sub-network Name	**Total Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8								
9		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		145.0	114.8	116.0	116.0	109.8	96.1
12	Class C (unplanned interruptions on the network)		107.5	105.2	102.8	100.5	98.1	95.8
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.71	0.51	0.51	0.50	0.43	0.36
15	Class C (unplanned interruptions on the network)		2.03	1.96	1.90	1.83	1.76	1.70

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028
Network / Sub-network Name	Dunedin Sub-network

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
10	**SAIDI**						
11	Class B (planned interruptions on the network)	87.0	68.9	69.6	69.6	65.9	57.7
12	Class C (unplanned interruptions on the network)	39.5	38.7	37.8	36.9	36.1	35.2
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.43	0.31	0.31	0.30	0.26	0.22
15	Class C (unplanned interruptions on the network)	0.73	0.71	0.69	0.66	0.64	0.61

Company Name	Aurora Energy Limited
AMP Planning Period	1 April 2018 – 31 March 2028
Network / Sub-network Name	Central Otago Sub-network

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
10	**SAIDI**						
11	Class B (planned interruptions on the network)	58.0	45.9	46.4	46.4	43.9	38.4
12	Class C (unplanned interruptions on the network)	68.0	66.5	65.0	63.5	62.0	60.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.28	0.21	0.21	0.20	0.17	0.14
15	Class C (unplanned interruptions on the network)	1.30	1.25	1.21	1.17	1.13	1.08

Schedule 13: Report on asset management maturity

Company Name	Aurora Energy
AMP Planning Period	1 April 2018 - 31 March 2028
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	We have revised our Asset Management Policy and this has been developed, approved and included in our AMP		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	We have determined asset management objective areas that support our corporate strategic priorities. Strategies for each fleet are summarised in the AMP, however, underpinning documents are currently being developed along with a strategic asset management plan and a set of key asset management documents.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	While we document stakeholder requirements, decision-making criteria, performance targets, strategic approaches and review processes for lifecycle management (which is well advanced for many asset types) there is room for further development and refinement in order to align with our corporate strategy and require approval.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	Our forecast models include work volumes and costs across the relevant time periods for all asset types and all stages of the life-cycle. We are beginning to expand the supporting documentation for these models		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Aurora Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Recent changes in the arrangements for works delivery set out a requirement for improved communication of the asset management plans. Scope for maintenance works has the potential to be developed and communicated further and an overall integrated works plan is being developed.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Internal position descriptions for our staff, and our contracts for outsourcing, provide reasonable clarity about the designation of responsibilities for the delivery of our actions set out in our AMP.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	Our present capability for contract and job management, work scoping, including resource requirements (and cost estimating) will be improved to see us consistently achieve efficient and cost effective implementation.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	Our existing incident management and business continuity plan documents require updating after our split from Delta. Our emergency management and communication plans are currently being revised.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name	Aurora Energy
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Manager roles have been developed with responsibilities for delivery of asset management policy, strategy, objectives and plans. Position descriptions for roles are broadly aligned with asset management strategy and objectives.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Substantial changes are taking place in our arrangements for works delivery, with implications for works delivery planning and management of outsourcing. We are not currently able to consistently demonstrate that sufficient resources are available.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Communications associated with the appointment of a new GM of Asset Management and Planning in the first half of 2018 emphasise the need to meet asset management requirements, including a commitment to seek ISO 55000 certification. A Health and Safety Policy, and a Customer Charter have been published on our website. There are regular team briefings and newsletters from top management to all staff.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	As a consequence of the separation from Delta, we are implementing improved capability in contract and job management, to help ensure the compliant delivery of our strategies and plans. Improvements are also needed in the performance monitoring regime for outsourced activities.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	**Aurora Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	We are still developing as an organisation following the formal separation from Delta. We have significant capability needs that still need to be addressed to improve asset management performance which are still in the process of being identified.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	1	Position descriptions for asset management roles include requirements based on our understanding of good industry practice. Competency registers are maintained for those people who require safety-related operational competences for field work. We do not, however, currently have a framework for asset management competency.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	1	Competency assessment had not been an important part of our recruitment processes for asset management related roles, and our development of staff. However, these competency assessments are now being introduced, and will be formalised as we develop a framework for asset management competency.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Company Name	Aurora Energy
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	We currently have gaps in the communication of asset management information. Improvements are needed to effectively communicate asset management strategic priorities, objectives and other pertinent asset management information, however are working to approve and publish key asset management documents which should serve to enhance communication with our employees and stakeholders.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Many elements of the asset management system are in the process of being documented, however this area is still a work in progress.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1	There is an understanding of what our asset management information systems should contain, however, we have yet to develop or implement an asset information strategy, and develop people to fulfil the roles of data owners and data stewards or formally define information requirements.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	1	There is an understanding within our organisation about what good practice involves, however, we have yet to fully develop and implement: data governance processes; data quality standards; and data gathering and improvement plans.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name	Aurora Energy
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	1	We recognise the need for a major review of our asset management information systems, to make them more relevant to the needs of users. Improvements are needed in: work and contract management; accessibility of information for diverse users – particularly for management via outsourcing; systems to support improvement in data quality; and efficient and effective linkages with other systems.	We are in the early stages of developing our approach to this review.	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	We have a large number of processes in place that manage risk, but we require a clearly documented and approved overall approach. Improvements are needed in: clarity about the diverse risk-based approaches to life-cycle decision making for various fleets, and risk-based decision making for the network; and the design and implementation of criticality frameworks.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	We mandate skill requirements for critical operational safety related tasks, in response to our understanding of the risks. We have a People Strategy, however, identification of future resource, competence and training requirements is at an early stage of development and we are yet to apply formal risk assessment to inform this process.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	We are in the process of developing a draft register (framework) of compliance requirements and we subscribe to "Comply With" for internal compliance identification purposes.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Company Name	**Aurora Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	We are currently making significant changes to how we deliver asset management plans through outsourcing. Major progress has been made, however some gaps still remain. Works delivery planning and management is a key area of focus. While we hold an extensive set of technical standards across four platforms, much of this is legacy content that requires updating. A new controlled documents system is currently being launched.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	Preventive maintenance policies and procedures have been developed for most asset types, however, robustness in implementation is limited by the gaps in job and work management capability, and the associated lack of an enterprise asset management system. Outsourcing contracts currently being implemented will include key result areas to enable high level monitoring.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	Improved outsourcing arrangements will seek to achieve reliable feedback on the causes of failures and incidents, and also form preventive maintenance and inspection regimes. Application of condition assessment is improving and we have developed initial asset health models.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2	Responsibility for processes for handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances are part of our improved outsourcing arrangements. Our incident and emergency management and escalation documents require updating after our split from Delta.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	Aurora Energy
AMP Planning Period	1 April 2018 – 31 March 2028
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	WSP-Opus is currently undertaking a major external review of our asset management systems. While we do not currently have our own systematic programme of self-review or audit of asset management as a whole, we have arranged external reviews of aspects of our asset managementarrange external audits of our Public Safety Management System on a periodic basis; and undertake safety observations of field work practice.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	Performance and condition measures are currently being incorporated into fleet strategies and responsibilities for corrective and preventive action are reasonably well understood within our organisation, however, these require documentation. There are some gaps in our processes for identifying and communicating the root cause of failures and incidents.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	1	Regular meetings are held to review operational incidents, to improve the understanding and classification of causes. Asset condition information is obtained during inspections and other maintenance interventions, however we do have some gaps in the process.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	We regularly engage with leading suppliers and consultants. Our staff are members of industry and professional bodies, and attend industry conferences and trade shows. We would however, benefit from a formal process for scanning the technology horizon and prioritising our engagement.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
Differences between constant and nominal forecasts are a direct output of out escalation approach. Our expenditure forecasts were determined in constant 2018 dollars and escalated to nominal dollars using forecast price indices. Each expenditure category is escalated separately using price indices specific to that category. Price indices for each expenditure category reflect a combination of labour and materials prices. Forecast labour and materials prices are sourced from NZIER and the World Bank. Where used, forecast CPI was sourced from NZIER. We explain our approach to forecast escalation in Chapter 8.

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

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
Our approach for operational expenditure is equivalent to the approach for capital expenditure, described above.

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C. Reliability Management Plan

Our Reliability Management Plan (RMP) aims to achieve continuous improvement in our approach to managing network reliability, both in terms of planned and unplanned interruptions. It will also bring our reliability management approach into line with good industry practice, while finding an optimum balance between performance, cost and risk.

Our RMP will evolve over time as we continue to identify, develop and implement a range of improvement initiatives.

The improvements to be developed and implemented through the RMP will incorporate recommendations from external reviews and the feedback associated with historic breaches of regulated quality standards.

This document sets out a summary of our Reliability Management Plan, including some analysis of historic performance.

The context

We exceeded our SAIDI limits during the last four regulatory years. The SAIFI limits were also exceeded during RY16 and RY18. Further details are provided in the Supporting Analysis section below. We have also published an analysis of reliability performance in our Annual Compliance Statement for the assessment period ending 31 March 2018 The SAIDI and SAIFI limits have been exceeded because of the combined effects of both planned and unplanned interruptions.

Planned interruptions

We are currently undertaking a large scale, multi-year programme of asset renewals. In many cases, these asset renewals require interruptions of supply so that the work can be performed safely. In addition, there have been changes in safe work practice across the electricity industry that have significantly reduced the extent of work that can be carried out live. The combined effect of these factors is a step-change in planned interruptions – well above the historical levels of SAIDI and SAIFI that are inherent in our regulatory limits.

Unplanned interruptions

Analysis of the underlying raw data about unplanned interruptions (before normalisation) reveals a slowly deteriorating trend in unplanned SAIDI over the past 15 years, but an improvement in unplanned SAIFI over the same period.

Relationship with health and safety management

Asset failures that cause unplanned service interruptions can also cause health and safety risks to workers or to members of the public. In addition to improving overall reliability performance, these initiatives will also prioritise reducing the safety risks associated with asset failures.

Objectives

Our key objectives for reliability management are to:

- bring our reliability management approach into line with good industry practice, and achieve an optimum balance between performance, cost and risk, and
- achieve continuous improvement in our approach to managing network reliability with a view to ensuring we meet the preferences of customers and comply with applicable regulatory standards.

The following sections of this plan set out more detailed objectives for reliability management, and the steps that we will take to improve and optimise reliability performance.

Scope

Our RMP focusses on understanding historic and current operational performance, and defining improvement initiatives that will be of long term benefit to customers.

The main focus areas for our RMP are set out below:

Governance and reporting

- Improved governance to ensure that visible, effective steps are being taken to manage and improve performance against quality standards.
- Fit-for-purpose operational reporting.

Stakeholders

- Minimise the impact of outages on customers, in line with the Customer Charter.
- Improve compliance reporting and analysis/commentary provided to stakeholders.

Outage reduction

- Minimise the frequency and duration of outages.
- Maximise the work safely undertaken during planned outages.

Strategy and analysis

- Produce fit-for-purpose documents (for example a network reliability strategy / network quality performance report).
- Improve analytics to support compliance strategies.
- Develop forecasting capability to allow improved SAIDI / SAIFI.

Reliability Management Plan Initiatives

The following table sets out an overview of the main areas of activity in the initial phase.

Reliability Management Plan initiatives

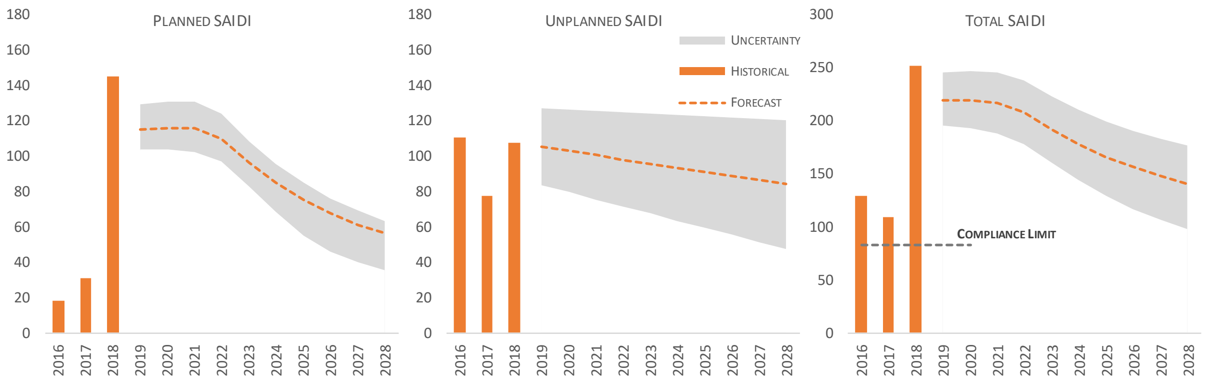
AREA	INITIATIVE	SUMMARY
Governance and reporting	Enhance reliability reporting	Review the requirements of stakeholders for reliability reporting and the information they need to better drive improvement initiatives.
	Develop template for reviews of major events.	Promulgate a template to improve the analysis and reporting of major events, and identify opportunities for improvement.
	Review of preventive maintenance	Undertake a review of preventive maintenance to assess compliance with specified requirements, and the effectiveness of these maintenance activities
Stakeholders	Directly contact key customers in advance of planned outages	As a backup for the standard planned outage notification process via energy retailers, we directly contact key customers to ensure that they are aware and are prepared. Typically, these key customers are schools and businesses, and medically dependent persons in individual residences.
	Improve business engagement prior to planned outages with major impacts	Trial “Outage Notification Drop Ins” with our team. This will occur when there is a planned outage that effects a densely populated business area e.g. – major shopping mall. The customer service staff will visit each business included in the outage to ensure they have been notified by their retailer and answer any questions.
	Improve visibility and communication during outages	Utilise the capability of the outage management system to improve visibility of outage impacts on customers, and enable our customer service staff to provide more detailed and accurate information to customers for both planned and unplanned outages.
Outage reduction – planned outages	Optimise planned outage work in outage windows	Undertake an end-to-end review of the works planning and delivery process, with a focus on improvements that will enable more bundling of work into planned outage windows.
	Initiate systematic ex-post review of planned outage performance	Establish a process for systematic ex-post review of planned outages, e.g. capturing data about planned outages that significantly over-run their planned duration, and identifying avoidable planned outages that result from the need for re-work or missed opportunities for works co-ordination.
	Temporary generation policy	Document and publish the criteria for the provision of temporary generation to mitigate planned outages.
Outage reduction – unplanned outages	Initiate systematic ex-post review of fault response performance	Establish a process for systematic ex-post review of service provider fault response performance, to identify opportunities for improvement in timeliness and effectiveness of response.

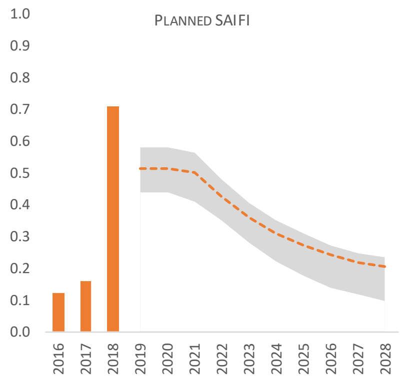
AREA	INITIATIVE	SUMMARY
Strategy and analysis	Enhance reliability analytics	Improve the analysis of unplanned outages to provide increased understanding of controllable and uncontrollable causes, including vegetation-related outages and equipment type failures.
	Improve analysis of "line down" incidents	Improve the quality of data and the analysis of "line down" incidents to provide a deeper understanding of the contributory factors.
	Network architecture changes to enhance reliability	Review network architecture to determine where additional resilience capability can be provided economically through the use of inter-ties, or minimising the impacts of faults using additional reclosers, sectionalisers etc.
	Vegetation management strategy	Review the approach to vegetation management to identify opportunities for improvement.
	Systematic ex-post review of protection	Develop an issues paper to outline the potential benefits of a systematic ex-post review of protection performance, including the priority areas (e.g. subtransmission).
	Protection performance report records system	Develop and implement a systematic approach to the preparation and storage of protection performance reports.
	Improved access to data from the PowerOn Fusion OMS	Develop an approach that will enable wider business access to the data about outages that is available (or will become available) in the PowerOn Fusion system.

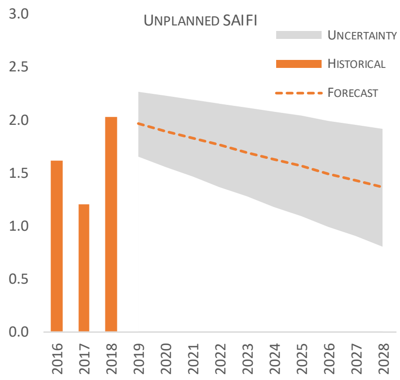
Reliability Forecasts

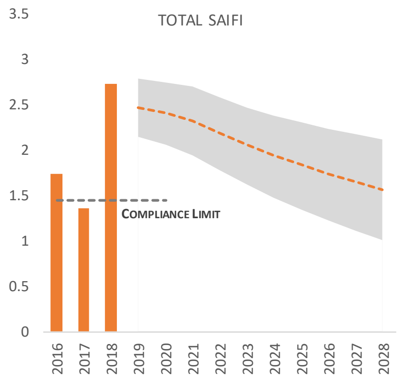
One of the objectives of the reliability management plan is to improve our understanding of the key factors that have historically driven planned and unplanned SAIDI and SAIFI. This will support more accurate forecasting of quality measures, which is important to understand the impact of various initiatives that we are considering.

To date we have developed simple models for forecasting planned and unplanned SAIDI and SAIFI for the 2018 – 2028 period. The outputs of these models are reflected in the figures below.









The planned SAIDI/SAIFI forecast assumes a reduction in planned SAIDI/SAIFI from about 2021, reflecting planned expenditure, increased efficiency in delivering large volumes of work and increased network security/redundancy. An uncertainty band around the forecast is shown. Notably, it is considerably smaller than the uncertainty band for the 'unplanned' forecast, reflecting that the greater predictability and controllability of planned work. However, uncertainty remains due to incomplete knowledge regarding the overall condition of our asset fleets.

The table sets out the associated forecasts for the next five years (consistent with Schedule 12d).

SAIDI		2019	2020	2021	2022	2023	2024
Planned	Forecast	115	116	116	110	96	85
Unplanned	Forecast	105	103	100	98	96	93
Total	**High**	**246**	**246**	**246**	**238**	**223**	**210**
	Forecast	**220**	**219**	**216**	**208**	**192**	**178**
	Low	**196**	**192**	**188**	**179**	**161**	**144**

SAIFI		2019	2020	2021	2022	2023	2024
Planned	Forecast	0.51	0.51	0.50	0.43	0.36	0.31
Unplanned	Forecast	1.96	1.90	1.83	1.76	1.70	1.63
Total	**High**	**2.79**	**2.75**	**2.70**	**2.59**	**2.48**	**2.39**
	Forecast	**2.48**	**2.41**	**2.33**	**2.19**	**2.06**	**1.94**
	Low	**2.16**	**2.06**	**1.95**	**1.79**	**1.63**	**1.48**

Our current unplanned SAIDI model is similarly simplistic. It forecasts a declining trend over time, based on an assumed annual improvement rate. This assumption is reasonable because:

– Our planned expenditure on renewals is reasonably expected to result in less unplanned failures
– We have a number of network reinforcements planned which have the objective of reducing the number of customers affected by an outage and improving restoration times, which will improve our SAIDI/SAIFI over time

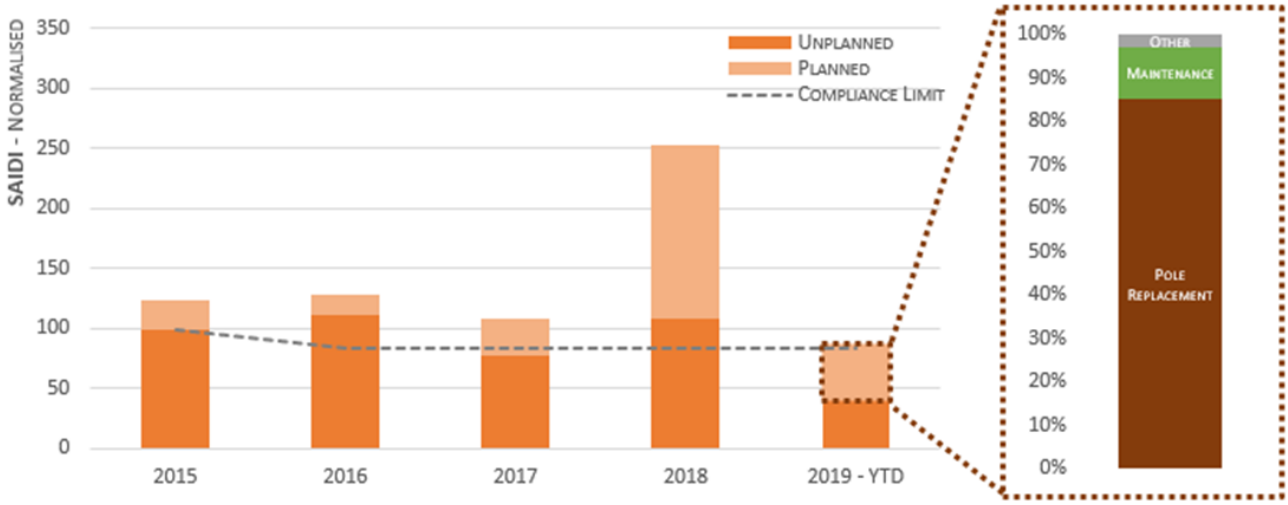
The unplanned forecasts have a much wider uncertainty range (relative to the planned forecasts) because much of the unplanned work is driven by adverse weather, and these weather events occur randomly.

Going forward we plan to focus on correcting outage data, and linking it to asset data to enable more sophisticated reliability forecasting using techniques such as survivor curves. Once we have these tools, assets that get replaced will have a direct impact on the expected availability of the fleet which is directly related to unplanned SAIFI/SAIDI.

Supporting Analysis

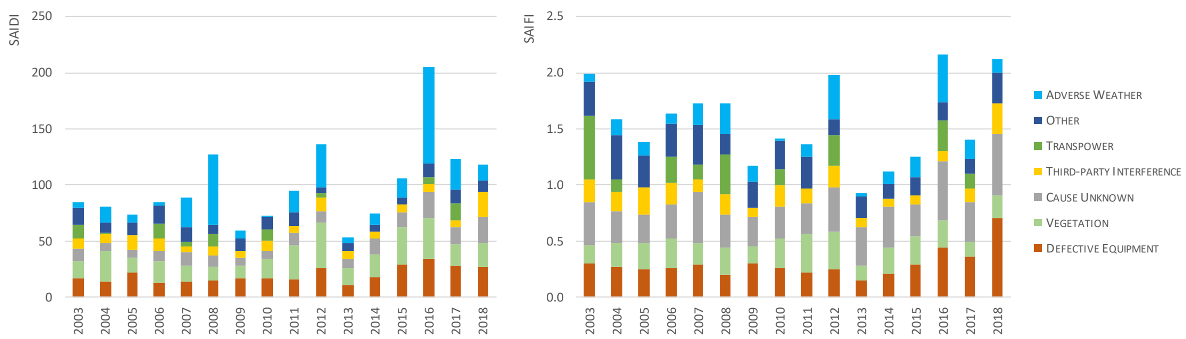
The figure below shows the historic trend of planned and unplanned SAIDI (normalised), together with a breakdown of the drivers of planned SAIDI for the regulatory year to date (5 months).[102] This clearly shows that our major programme of pole replacement is the main driver of planned SAIDI in the current year.

Trend of Planned SAIDI (normalised)



The following figure presents a 15 year trend of unplanned SAIDI, broken down by identified causes.

Trend of unplanned SAIDI/SAIFI



It can be seen that in most years, the predominant causes are:

- Adverse Weather
- Vegetation
- Defective Equipment.

Adverse weather

In years with exceptionally high unplanned SAIDI, Adverse Weather is the dominant cause.

102 The regulatory definitions of SAIDI and SAIFI incorporate a range of adjustments of raw data, before the final value for reporting performance is determined. This process is known as 'normalisation'.

However, there is a need for more understanding about the extent to which these unplanned interruptions during severe weather could potentially have been reduced or avoided. For instance, in some cases, a more resilient design, or investment in some form of back-feed capability may have allowed a significant reduction in the SAIDI for the event.

A further factor in understanding historic performance is the extent to which an interruption classified as Adverse Weather may have resulted at least in part, from other contributory causes. One example is vegetation contact with lines during high winds, in circumstances where that vegetation could potentially have been managed to reduce or eliminate the risk.

More details about incidents recorded as “conductor drop” are provided on later in this section.

Vegetation

Vegetation is a significant contributor to unplanned interruptions. Recent improvements in vegetation management practices may be beginning to show benefits in stabilising and reducing the extent of unplanned interruptions. However, more time is required before conclusions can be formed with confidence.

Defective Equipment

There was a step change in the SAIFI attributed to “Defective Equipment” in 2018. However, further analysis reveals that the increase in SAIFI in 2018 is attributable to an unusual pattern of LV fuse failures that required HV isolation to allow safe replacement of the fuses. The underlying factors were:

- A marketing promotion of a ‘free hour of power’ by one energy retailer was widely taken up in some specific residential districts. Many customers in these areas elect to use their ‘free hour of power’ at the same time in the evenings, lead to significant overloading of the local LV network and fuse failure.
- The LV fuses in many of these installations were of an older design that does not permit safe replacement of the fuse element without de-energising the high voltage incomer.

If this overloading problem is removed, the 2018 “Defective Equipment” contribution to unplanned SAIDI is generally consistent with previous years.

Third party interference

The historic trend shows that third party interference is a material cause of unplanned SAIDI, and was particularly large during 2018. Our analysis shows that the increase in 2018 is mostly attributable to vehicle impacts on poles. There are typically few of these events each year, but they can cause significant unplanned SAIDI.

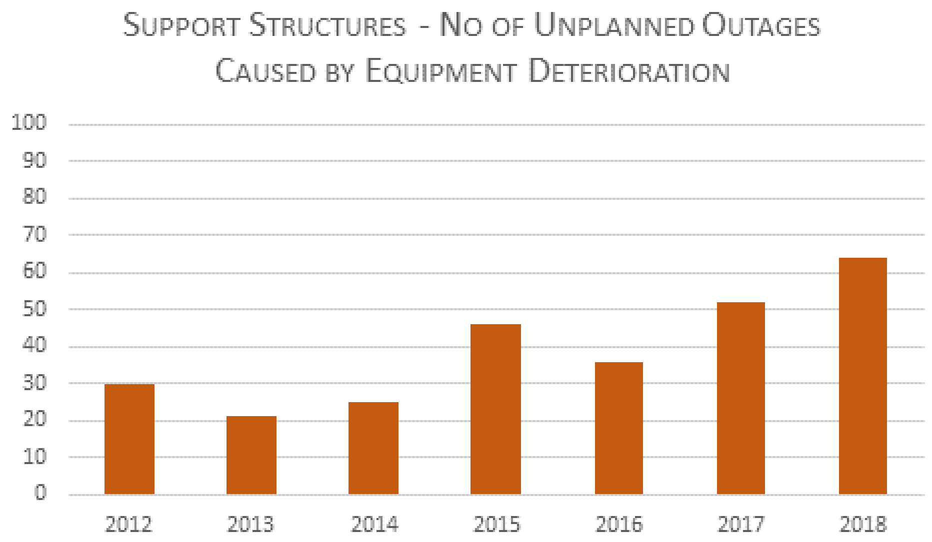
Cause Unknown

“Cause unknown” currently represents a significant proportion of the unplanned SAIDI events. Comparison of the relative influence of this “Cause Unknown” category between SAIDI and SAIFI shows that the majority of the “Cause Unknown” events are short duration. The typical scenario is an overhead feeder that is closed successfully after a fault, but the patrol of the line is unable to identify the cause.

There may be opportunities to improve the fault patrol process to reduce the number of “Cause Unknown” classifications.

Analysis of Overhead Structure failures

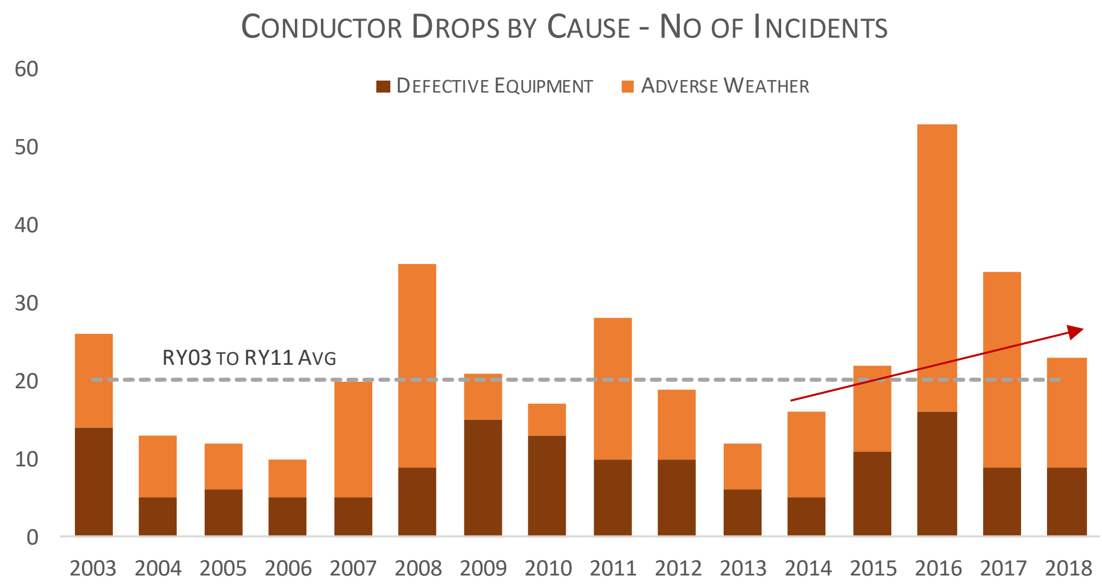
In recent years we have been seeing an increasing trend in the number of unplanned outages related to poles, crossarms and insulators. This may be indicative of a deteriorating condition of the asset fleet, but limited history and lack of data on unassisted failures means we are unable to draw definitive conclusions at this stage. However, as indicated by the chart below, it is likely that the number of unplanned outages of support structures caused by equipment deterioration has been increasing in recent years. Our current pole replacement strategy (refer to Chapter 5) reflects our recognition that a large number of our overhead structures are in a condition where replacement or reinforcement is warranted.



Analysis of Conductor Drop incidents

The following illustration shows the long term trend of incidents classified as Conductor Drop.[103] Conductor drop incidents over the past four years have been consistently above historical levels and are trending upwards – this is a major concern for us. Further analysis of these recent events indicates that snow and extreme winds are the primary cause of conductor drop/failure. Another factor that may contribute to this is the conductor type: as discussed in Chapter 5, the No.8 steel wire conductor is brittle and may be more vulnerable to breaking in these conditions. While we are not able control severe weather events causing conductors to fail, we are looking to progress analysis into our design standards ensuring better resiliency against weather events such as these. We are also planning to conductor renewals in this space (refer to Chapters 5 and 8). However we need to complete more detailed analysis to be able to balance investment levels against feeder criticality.

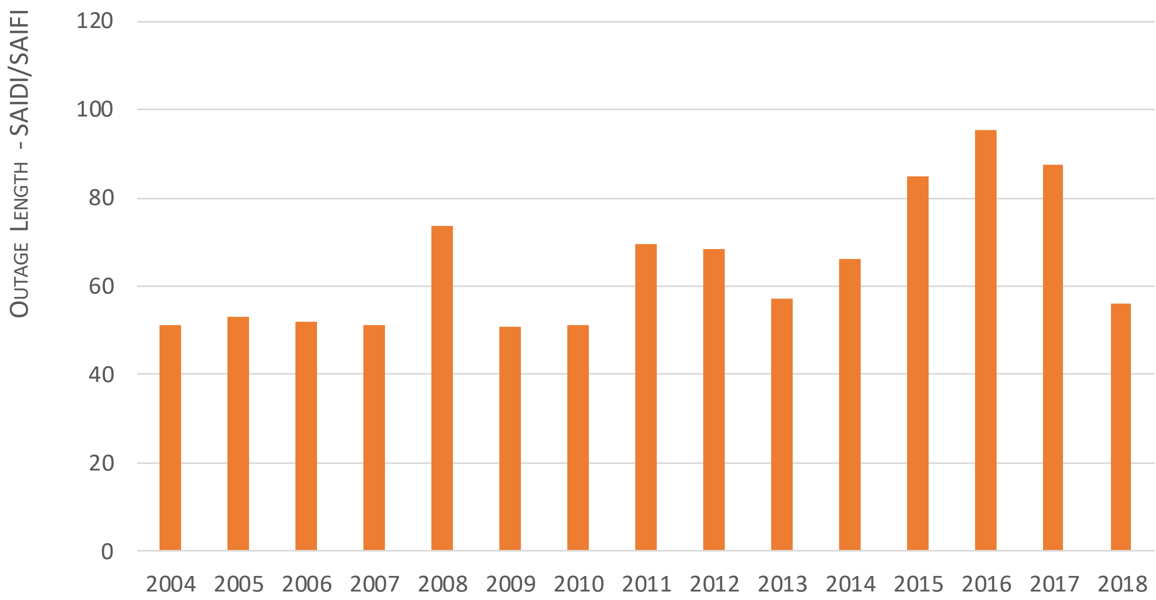
[103] We recognise that our classification of asset types in our outage data has inconsistency issues. However, this is the best source of knowledge currently available. We are seeking to improve the quality of this data going forward.



Analysis of interruption durations

Our response to unplanned interruptions has a direct effect on the extent of outage durations and the total impact on customers. The following chart shows the trend of unplanned outage durations, represented by the ratio of SAIDI to SAIFI.

Trend of unplanned outage duration



We are considering options that may be useful to reduce average outage duration, including:

- Installing more fault passage indicators
- Installing more reclosers in the network
- Better contingency planning and spares management
- Increased contractor resources.

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D. FURTHER RISK MANAGEMENT INFORMATION

The table below sets out our Critical Risk Areas (CRAs). It provides one or more examples of each, and describes the various controls we have in place to manage the risk. Note that the list of controls is not intended to be exhaustive, but rather to provide examples applicable to the broad risk descriptions.

			Controls in place		
	Description	Potential Scenario	Design	Procedural	Human
1	In-service equipment / asset failure leading to injury or fatality.	Conductor down causing fire event in high risk area	Standard designs Protection strategies	Line Inspections Vegetation control	Fault crew Emergency response
2	Loss of operational control resulting from unsafe practices being followed leading to injury or fatality.	Restoring supply to a fault that initiates a fire in a high risk zone External cyber attack	Standard designs Protection strategies Firewalls	Disabling automatic recloser functionality Visual line patrol before restoring supply after a fault	Trained Control Room operators Qualified competent field workforce
3	Inability to restore the network following a major event leading to prolonged supply interruptions with potential public safety implications (operational and emergency response resilience and business continuity).	Total loss of SCADA, Loss of supply to Queenstown CBD Ineffective emergency response / business continuity processes	Reductant systems Mobile substations Backfeed options Resilient systems and communications	Equipment Inspections Operating data analysis Emergency response procedures Contingency plans	Engineering expertise Response arrangements with contractors and other utilities
4	Inadequate and poor quality asset health data and planning resulting in an inability to appropriately manage and address network risks.	Catastrophic loss of minimum security (n) feeder or zone substation to populated area (Glenorchy, Omakau) Loss of specialised / custom asset (e.g. auto transformer) Extended outages	Data collection requirements Industry operating data Incident investigation	Inspection strategies Information systems (GIS, Asset database) Risk Management Framework	Fleet management experience Data systems management

	Description	Potential Scenario	Controls in place Design	Procedural	Human
5	Natural disaster (Dunedin, Queenstown, Cromwell) including earthquake, tsunami	Multiple fatalities Loss of ability to operate the network Significant loss of revenue	Redundant Control Rooms Insurance Safety in Design	Emergency preparedness MOU with other utilities and contractors	Senior Leadership team Multiple contracting arrangements
6	Failure to comply with relevant legislation and regulations leading to corporate and / or individual prosecution, government intervention and / or major stakeholder and owner confidence concerns.	Scenarios above. Qualified financial audit or failure to be certified on requirements for network license.	Policies, processes and procedures Industry best practice	Internal and External assurance activities Lessons learnt	Professional qualified experienced personnel Collaboration with industry and stakeholders

We draw upon records of incidents, inspections, experience and peer utility practice to determine the risk associated with assets and asset types and appropriate mitigations for these risks.

RISK LOSS/FAULT/EVENT	LIKELIHOOD	IMPACT	SOLUTIONS / MITIGATIONS IN PLACE
Serious harm incident caused by failure of network assets	Unlikely	Major	Quality design Strict safety specifications Preventative maintenance Follow up maintenance Fault response Effective renewal program
Overhead line section failure causes outages	Almost Certain	Moderate	Isolate faulty section or repair. Transfer load to alternative source (e.g. backfeed or generator)
Cable section failure causes outages	Very Likely	Moderate	Isolate faulty section or repair. Transfer load to alternative source (e.g. backfeed or generator)
Individual Circuit Breaker failure causes outages Catastrophic failure could damage other assets, for indoor switchboards some damage can be expected	Possible	Insignificant	Maintenance regimes, design (protection/housing) and equipment standards for breakers
Loss of supply from one or more Transpower grid exit points causes extended disruption to customers Severe reduction in supply capacity for hours, weeks or months over entire network or section of network	Unlikely	Major	Load management Customer information and management Relationship management with Transpower
Loss of 33/11 kV transformer at 'N' security substation causes outages Loss of supply for up to several hours	Unlikely	Moderate	
Loss of 33/11 kV transformer at N-1 security substation causes outages Loss of supply for up to several hours	Unlikely	Minor	Reduce load on remaining transformer (if necessary). Temporary backfeed support on 11 kV
Failure of 11 kV switchboard in zone substation causes outages Up to 24 hours loss of supply for some customers	Very Unlikely	Moderate	Isolate faulty section or repair. Transfer load to alternative source (e.g. backfeed or generator
33 kV Outdoor Bus failure causes outages Catastrophic failure could damage other assets	Unlikely	Major	Assess and repair as soon as possible. Design and install substation risk mitigations eg walls and containment
Indoor switchboard failure causes outages Catastrophic failure could damage other assets including the building	Very Unlikely	Major	Assess and repair as soon as possible. Design and install substation risk mitigations eg walls and containment

Risk loss/fault/event	Likelihood	Impact	Solutions / Mitigations in place
SCADA system failure causes outages Major failure will result in loss of monitoring and control	Unlikely	Minor	Redundancy and backup on key components (including software)
Pandemic impacts network operations leading to widespread outages Asset Management Capability	Rare	Minor	Use corporate contingency procedure

E. ICT ASSET INFORMATION

This appendix provides further information on the ICT systems that support our electricity business.

Information Systems

We use the following information systems – described below – as part of asset management:

- Geospatial Information System (GIS)
- Network operations systems
- Customer and commercial systems
- Corporate systems
- Enterprise technology and infrastructure requirements

GIS

We use a GIS to capture, store, manage and visualise its network assets. GIS is the master system for current assets in the network, but it also distributes and informs other systems about the current assets.

An important user of this data is our finance system, which in addition to delivering the financial capability, also forms part of the work management system for the business. The asset spatial information is also a key input into renewal and outage scheduling where geographical and network hierarchy factors are considered in the planning, monitoring and improvement of the asset base.

Network operations

Our network operations rely upon real-time information systems including SCADA, distribution and outage management systems. These systems are critical to the safe and reliable operation of the network and must achieve exceptionally high reliability.

Over the next two to three years we plan to extend our remote monitoring and control capability into the LV network and increase the ability to access real time systems from mobile devices.

Our main operational platform is the SCADA system. It requires a significant lifecycle replacement investment within the planning period.

Customers and commercial systems

Our customer and commercial business services include billing, case management and regulatory compliance.

Our business requirements include new case management capability to work in parallel with our new operational technology platforms, so that we can offer improved notifications to our customers about outages and likely restoration times.

Corporate

Our corporate services cover all non-network and customer related activities including finance, human resources (HR), legal and property. Our current financial management and HR technology services are relatively mature.

However, there is a need for intervention with respect to the Financial Management system within the planning period because of an expected obsolescence/cessation of product support. The final decision about the most appropriate intervention will depend on whether a transition to a subscription service (with lower capex and higher ongoing opex) is efficient and practical, compared with capital investment.

Enterprise technology and infrastructure requirements

Our core ICT infrastructure also requires on-going renewals and some improvements in capability.

This portfolio covers the enabling technology and generic technology frameworks and platforms that enable mobile access to business services, integrate standalone data sources and analyse information as well as support the processing, storage and exchange of digital information around the company and to its contracted parties.

Expenditure in this portfolio early in the planning period reflects completion of the overhaul of our voice and digital communications to support operational technologies. Many of the services provided in this portfolio are delivered through the cloud with the result that capex is relatively low.

Control and Integration

We need to protect the integrity of asset information held in our systems. The system and processes we deploy have security controls in place to restrict access, a change management process to control system changes, and are fully backed up on- and off-site.

Limitations and Initiatives to Improve Data

We are continually working to improve the asset data we maintain in our systems. Obtaining high-quality information to support our asset management activities can be problematic, for example ensuring consistent recording of information in the field and managing changing information requirements. We are constrained by some of the current systems' inability to share information, and by the limited integration options.

Our current asset management information systems do not fully meet our needs. We require improved capability in our information systems that will allow us to:

- apply data standards and templates within the information systems, to improve the quality of asset information
- improve the quality of asset attribute, transactional, and condition assessment data by enabling input directly from mobile devices, with validation at the point of entry
- more effectively manage work on assets, including defining and planning work, managing jobs and work orders, and recording the work carried out.

For the purposes of asset planning in particular, we require improved capability to:

- visualise asset condition, work order and defect history
- visualise selected asset performance data from real time systems
- undertake predictive analysis and develop forecasts of risk and intervention needs
- define and manage plans and programmes of interventions
- apply reference cost tables to forecast interventions, particularly for the costs of high volume, standard types of work
- understand financial implications of decisions

- link capital expenditure and operating expenditure forecasts to company financial models
- access multiple data sources, both internal and external, for scenario modelling,

To address this, we continually assess where new approaches and investments should be made to improve the management of available data. Under the planned AMDP we have a range of initiatives that focus on making better use of data we already collect and to deliver improvements to our approach for capturing and managing new information.

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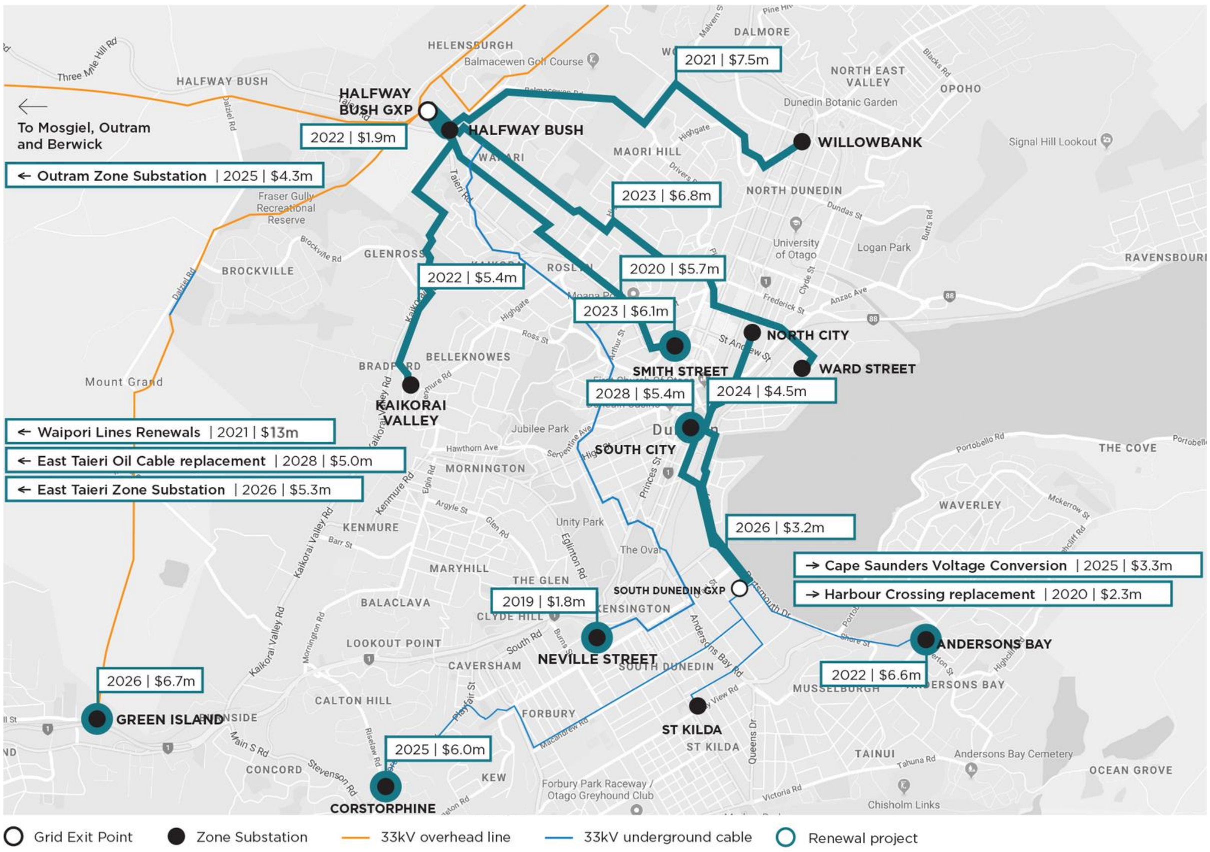
F. MAJOR PROJECTS DETAIL

This appendix provides an overview of some our large network projects planned for the period.

Dunedin Projects

Over the next ten years we plan to spend over $150 m on large projects to renew, upgrade and expand our networks. A selection of these projects are set out on the three maps below, colour coded to denote whether the investment is driven by renewal or growth. These works are in addition to our programme-based work such as pole renewals.

Large planned projects in Dunedin



The year indicated for project completion ends at 31 March in each case.

Much of the Dunedin network was constructed 50-70 years ago and many of its assets are near end-of-life, requiring renewal over the AMP period. This coupled with historical low rates of replacement mean we will replace assets including 33 kV cables, power transformers and switchgear over the AMP period. Example projects include:

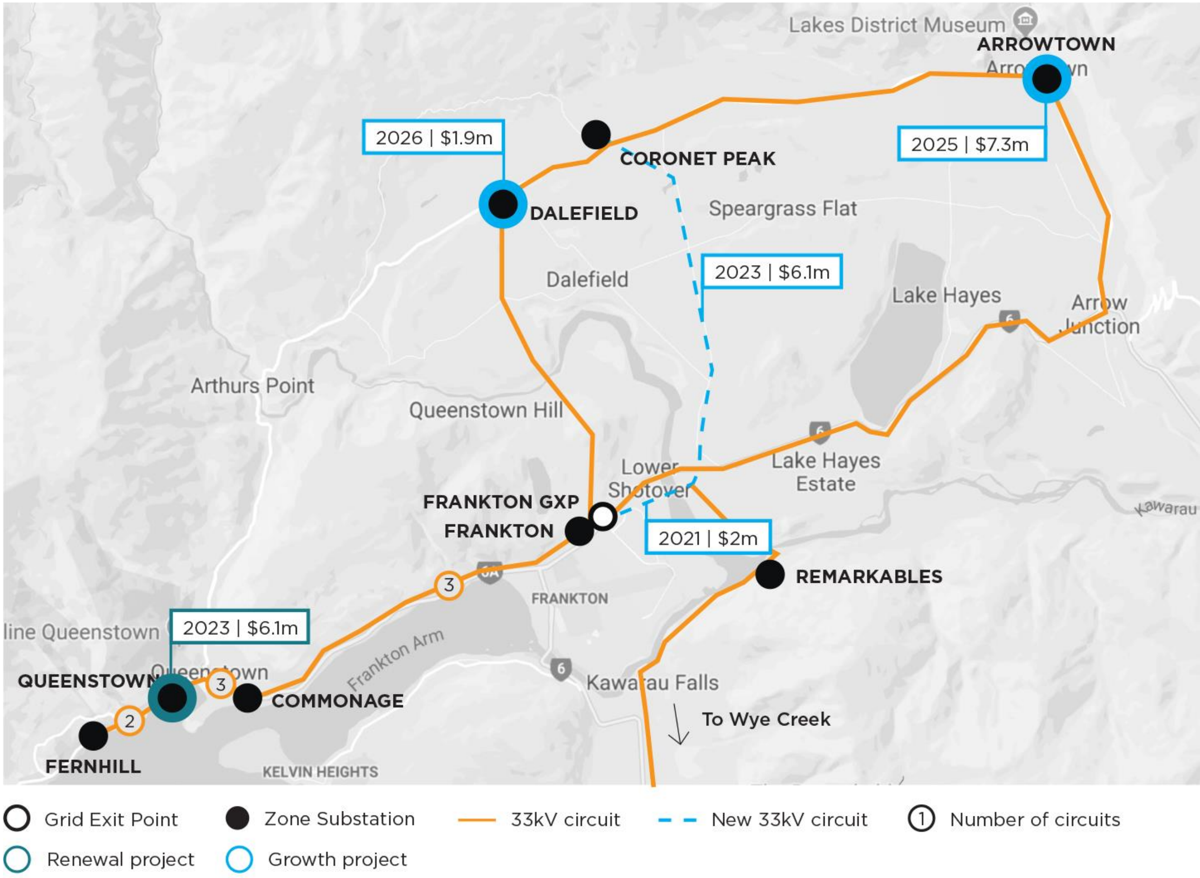
- rebuild of the Waipori subtransmission pole lines from Halfway Bush to Berwick
- the steel lattice structures and associated poor condition conductors that span Dunedin harbour
- the Neville St substation, to be replaced with a new zone substation at Carisbrook. This project is underway, with the majority of the new substation complete.

No growth projects are planned for the Dunedin network.

Central Otago Projects

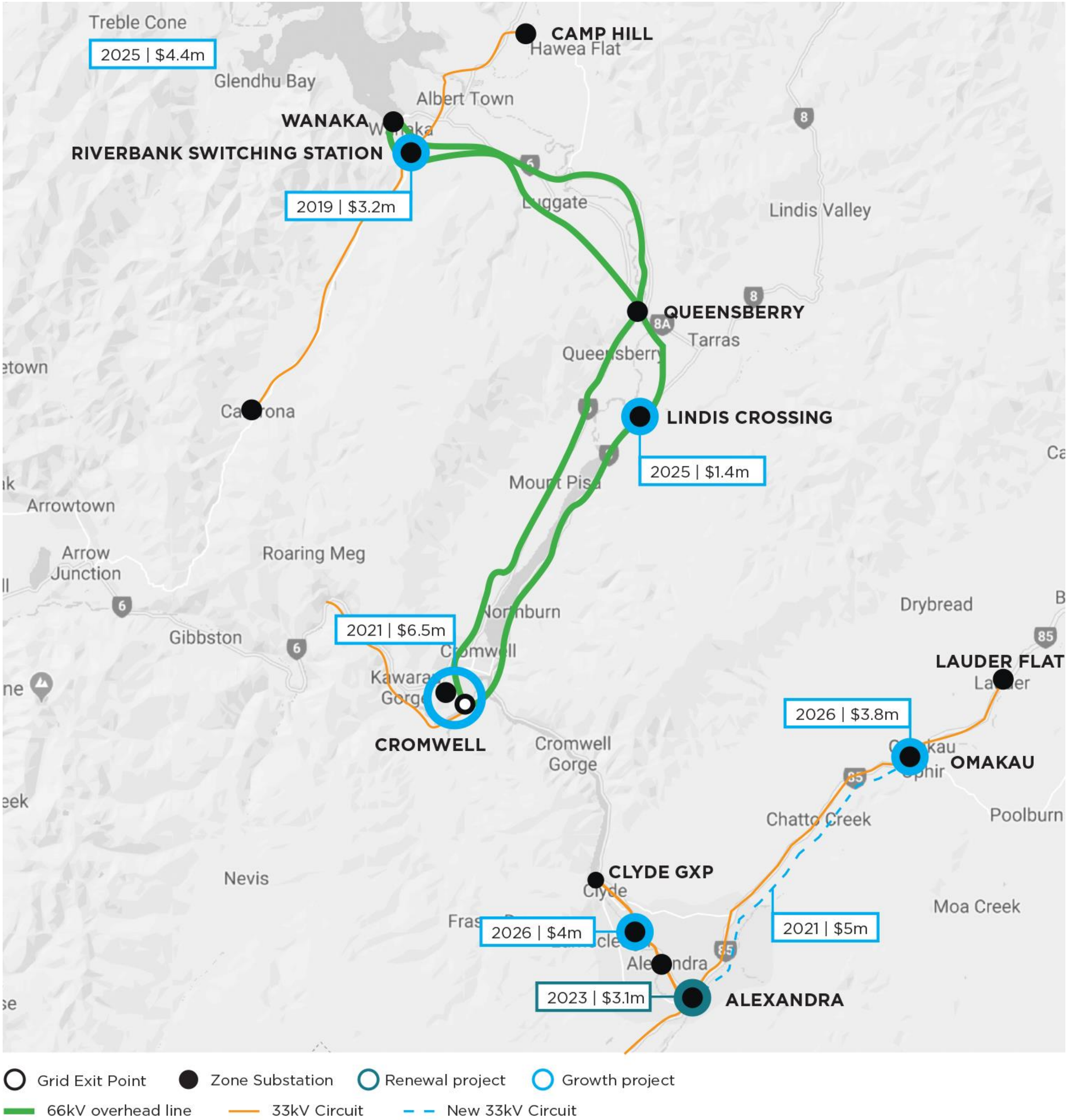
Large projects on our Central Otago networks are driven by demand growth, including residential development and expanding tourism operations. As discussed above, we expect this region to continue to grow and we are engaging with local councils to ensure our investments facilitate this growth.

Large planned projects in Queenstown Lakes and Central Otago



The year indicated for project completion ends at 31 March in each case.

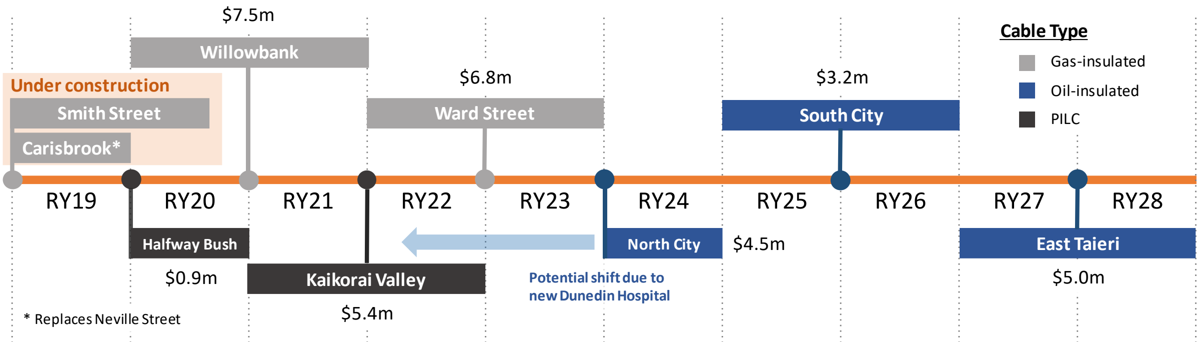
We are planning a larger number of growth projects, including upgrades of the Arrowtown, Dalefield, Lindis Crossing, and Cromwell zone substations and the Riverbank Road switching station. We will also build a new 33/11 kV line to supply Treble Cone ski field and a second 33 kV line to Omakau. A new feeder from the Frankton GXP to the Shotover River to increase the capacity of the Wakatipu Ring, supplemented at a later date by a second project that extends the feeder to Coronet Peak


Treble Cone
2025 | $4.4m
Glendhu Bay
CAMP HILL
Hawea Flat
Albert Town
WANAKA
RIVERBANK SWITCHING STATION
2019 | $3.2m
Luggate
Lindis Valley
QUEENSBERRY
Tarras
Cardrona
LINDIS CROSSING
2025 | $1.4m
Arrowtown
Arrow Junction
Roaring Meg
Gibbston
Drybread
2021 | $6.5m
LAUDER FLAT
2026 | $3.8m
CROMWELL
Cromwell Gorge
OMAKAU
Chatto Creek
Poolburn
Nevis
CLYDE GXP
Moa Creek
2026 | $4m
2021 | $5m
2023 | $3.1m
ALEXANDRA
Grid Exit Point
Zone Substation
Renewal project
Growth project
66kV overhead line
33kV Circuit
New 33kV Circuit

Dunedin cable network

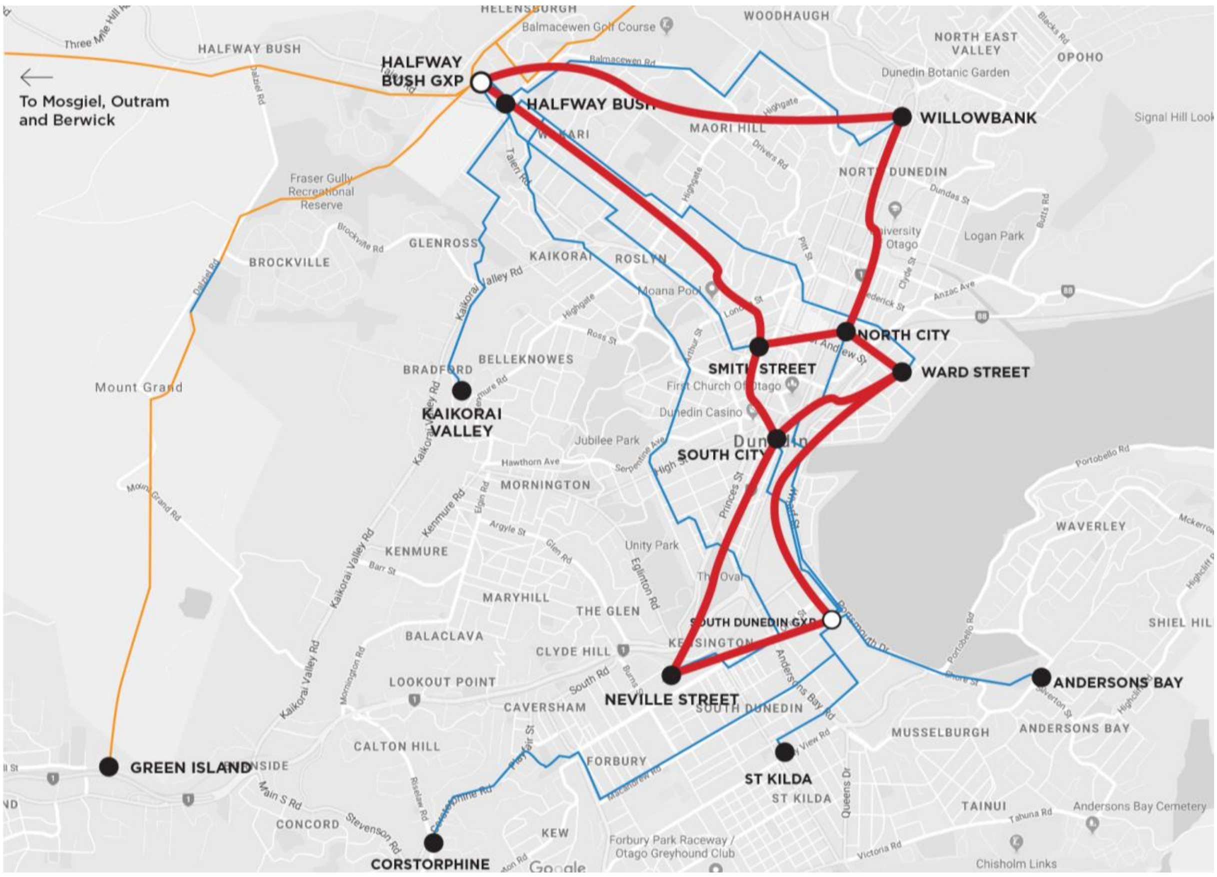
The backbone of the grid supplying Dunedin is the subtransmission cable network. A series of high voltage 33 kV underground cables take supply from the national grid at Halfway Bush and South Dunedin and distribute it to zone substations throughout the city.

Planned Dunedin 33 kV subtransmission cable replacement



As most of the city's subtransmission cable is coming due for replacement, we have been progressively upgrading the older types of gas-filled, oil-filled and PILC cables to modern cables that use solid insulation. The Andersons Bay, Carisbrook and Smith Street cables have been replaced or under construction. As shown above, we plan to replace most of the remaining subtransmission cables.

Potential reconfiguration of the Dunedin subtransmission network



At the same time as renewing the cables, we are investigating a plan to reconfigure the subtransmission network to enhance its resilience in the event of a major event such as an earthquake. The current hub-and-spoke arrangement would change to a meshed network with more interconnection, providing flexibility to switch supply between grid exit points and zone substations.

Summary Table

The following table sets out our planned major projects for the AMP planning period.

PROJECT	FROM	TO	EXPENDITURE
Establish new Feeder from Frankton GXP Coronet Peak is currently fed from the "Wakatipu Ring"; demand from the Ring has exceeded its n-1 capacity during the winters since 2012. To increase the capacity of the ring we propose installing an additional 33 kV feeder from the Frankton GXP. Initially this feeder would only run as far as the Shotover River; it would be extended to Coronet Peak (see "Extend New Frankton 33 kV Feeder to Coronet Peak" project, below) at a later stage.	2019	2021	$2 to $3 m
Extend New Frankton 33 kV Feeder to Coronet Peak Additional growth in the wider Arrowtown area will require additional capacity in the Wakatipu Ring. To relieve this constraint, we propose extending the new Frankton 33 kV feeder (see project above) to Coronet Peak. The final route and termination point of the feeder will be dependent on the quantity of growth across the Dalefield, Coronet Peak and Arrowtown substations.	2023	2023	$6 to $7 m
Second 33 kV line to Omakau This project enhances security/reliability of supply in the area and makes provision for further irrigation growth in the Omakau area. There is a reasonable level of uncertainty around future irrigation development in the area and this project will not progress until we have confidence in continued irrigation development.	2021	2025	$5 to $6 m
Install 24 MVA transformers and new switchgear at Arrowtown zone substation Arrowtown substation demand exceeds its firm rating of 7.5 MVA. We propose rebuilding Arrowtown substation with new 24 MVA transformers to achieve N-1, and increase the total number of 11 kV feeders to eight, with room for future additions. A new building will also bring the substation up to modern seismic standards. The project will be delivered in two stages: (i) switchboard install, and (ii) new transformers.	2021	2025	$7 to $8 m

PROJECT	FROM	TO	EXPENDITURE
Install two new 24 MVA transformers at Cromwell substation Cromwell is located on the busy main road between Wanaka and Queenstown and sees a large amount of tourist traffic. The load at Cromwell is growing and peak demand now exceeds the substation's 9 MVA firm capacity. We are planning to replace the existing transformers with new 24 MVA rated transformers, to restore N-1 security.	2019	2020	\$4 to \$5 m
New Omakau substation Irrigation load may continue to rise above firm capacity at Omakau. The existing substation site is constrained by the road reserve area it occupies and has possible flooding issues. Land has been purchased at a new site north of Omakau and work is well underway to establish a mobile substation parking bay there. Eventually, we propose developing this site into a full substation. In the shorter term, the 3 MVA transformer from Maungawera (now decommissioned) has been installed at a new site on Lauder Flat road to provide additional capacity.	2024	2026	\$3 to \$4 m
Install 24 MVA 66/11 kV transformer and 11 kV switchgear at Riverbank Road substation Continuing load growth in the Wanaka township has created a situation where many of the feeders are difficult to off-load at peak load times and a cable fault within the town during peak load would result in a significant outage. This project proposes installing a transformer and switchgear at the Riverbank Road site to enable the connection of new 11 kV feeders.	2022	2024	\$2 to \$3 m
Rebuild Treble Cone line as 33/11 kV The Treble Cone ski field currently runs generators to supply its own peak demand and avoid overloading its existing supply capacity. The ski field proposes upgrading supply capacity to it and ceasing self-generation. We plan to construct 33 kV over 11 kV lines to Treble Cone, running them in parallel at 11 kV. This will enable the new load (currently generated by the ski field itself) to be supplied within an acceptable voltage range.	2020	2022	\$2 to \$4 m

PROJECT	FROM	TO	EXPENDITURE
New Treble Cone Substation Design and Build The project to rebuild the Treble Cone line (above) provides a short term fix to provide additional capacity while maintaining voltage. However, if load does continue to grow, further investment is required to increase the capacity of the network in the area. This project makes provision for the installation of a new 33/11 kV zone substation in relatively close proximity to Treble Cone ski field.	2023	2025	\$2 to \$3 m
Install 3rd 33/66 kV auto transformer at Cromwell GXP & create 66 kV bus Demand at the Cromwell GXP is currently 36.7 MW, relative to firm capacity of 41 MW, so it is currently under the N-1 limit. However, continued demand growth is forecast, predominantly driven by winter loads (ski fields winter tourism, domestic winter loads). The Upper Clutha 66 kV network capacity is restricted by the rating of the Cromwell 33/66 kV transformers. We propose installing a third transformer to relieve this constraint and provide future proofing.	2019	2021	\$2 to \$3 m
McDonnell Road 11 kV feeder reinforcement Arrowtown substation is located in McDonnell Road. A major trench was being opened for other infrastructure services along McDonnell Road. This project utilises the shared trench to install additional 11 kV feeder capacity to service growing residential and commercial demand. At the time of writing this AMP, this project was very close to completion.	2019	2019	\$2 to \$3 m
Upgrade Dalefield Substation Dalefield substation is nearly fully utilised, supplying approximately 3 MVA of mainly residential load. It is located very close to Coronet Peak substation which is also reaching full capacity. Further load growth will require a network upgrade in the area. This project makes provision for a transformer upgrade at Dalefield substation. The final solution for this project will depend on the location of growth and will need to be compatible with the new Frankton 33 kV feeder project described above.	2024	2026	\$1 to \$2 m

PROJECT	FROM	TO	EXPENDITURE
Upgrade Clyde-Earnscluegh zone substation A large irrigation scheme on the Clyde side of the river is now under construction. This scheme is likely to add 2 MVA to the substation load but this is not expected to coincide completely with the frost fighting peak. Damage to the 2 MVA transformer at the Clyde-Earnscleugh substation means that this substation is currently backed up by the mobile substation. Design work is currently underway to replace the failed second transformer at this substation.	2019	2021	$1 to $2 m
Second Transformer - Lindis Crossing Irrigation loads have resulted in substantial demand growth in the Queensberry and Lindis Crossing area. We will continue to monitor the need to increase capacity of these sites, which could be achieved by adding another transformer at Lindis Crossing.	2024	2025	$1 to $2 m
Jacks Point Cable We have previously proposed building a substation at Jacks Point when load was approaching existing overhead line capacity. However load growth at Jacks Point has been lower than expected and a large area of land expected to be subdivided is now to be supplied by OtagoNet Ltd. This has reduced the long term need for a substation, and it is now likely to be economic to supply Jacks Point via an 11 kV cable (in addition to the existing overhead line). This gives the added benefit of extra security.	2019	2020	$1 to $2 m
5 MVA Spare Transformer The network contains a number of small zone substations with single transformers. In some instances the mobile substation can be used to provide emergency response for transformer failures. This project procures and installs a 5 MVA emergency spare transformer at Alexandra substation. The transformer can be relocated in an emergency to other sites when required.	2019	2019	$1 to $2 m

G. DISCLOSURE REQUIREMENTS

This compliance matrix provides a look-up reference for each of the Commerce Commission's information disclosure requirements. The reference numbers are consistent with the clause numbers in the Electricity Distribution Information Disclosure Determination (2012) (consolidated as of 24 March 2015).

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6	*ASSET MANAGEMENT PLANS AND FORECAST INFORMATION*	
	Disclosure relating to asset management plans and forecast information	
2.6.1	Subject to clause 2.6.3, before the start of each **disclosure year** commencing with the **disclosure year** 2014, every **EDB** must- (1) Complete an **AMP** that— (a) relates to the **electricity distribution services** supplied by the **EDB**; (b) meets the purposes of **AMP** disclosure set out in clause 2.6.2; (c) has been prepared in accordance with Attachment A to this determination; (d) contains the information set out in the schedules described in clause 2.6.6; (e) contains the Report on Asset Management Maturity as described in Schedule 13; (2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and (3) **Publicly disclose** the **AMP**.	(1)(a) This is addressed in the Executive Summary. (b) Refer to 2.6.2 below. (c) Compliance with Attachment A is demonstrated in the remainder of this compliance matrix. (d) This information is included in Appendix B (1)(e), (2) Our AMMAT report is included in Appendix B (3) We have published the AMP on our website.
2.6.2	The purposes of **AMP** disclosure referred to in subclause 2.6.1(1)(b) are that the **AMP**— (1) Must provide sufficient information for interested **persons** to assess whether- (a) assets are being managed for the long term; (b) the required level of performance is being delivered; and (c) costs are efficient and performance efficiencies are being achieved; (2) Must be capable of being understood by interested **persons** with a reasonable understanding of the management of infrastructure assets; (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	(1)(a) Chapter 2 sets out a background on our business, chapter 3 provides an overview of our network and chapters 4 and 5 discuss the management of our assets. (1)(b) Historical reliability is detailed in the Executive Summary, chapter 2.3.4 discusses our performance and chapter 4.6 discusses our asset management objectives and strategy. (1)(c) We refer to expected efficiencies in a number of sections, including on our pole replacement programme in Section 5.4.4 (2) We have included a glossary in Appendix A which will aid in understanding. (3) Risk management and resilience is discussed in chapters 4.8 and 4.9. Asset performance and risks are discussed for specific assets throughout chapter 5.

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6.6	Subject to clause 2.13.1, every **EDB** must— (1) Before the start of each **disclosure year**, complete and **publicly disclose** each of the following reports by inserting all information relating to the **electricity distribution services** supplied by the **EDB** for the **disclosure years** provided for in the following reports— (a) the Report on Forecast Capital Expenditure in Schedule 11a; (b) the Report on Forecast Operational Expenditure in Schedule 11b; (c) the Report on Asset Condition in Schedule 12a; (d) the Report on Forecast Capacity in Schedule 12b; (e) the Report on Forecast Network Demand in Schedule 12c; (f) the Report on Forecast Interruptions and Duration in Schedule 12d; (2) If the **EDB** has **sub-networks**, complete and **publicly disclose** the Report on Forecast Interruptions and Duration set out in Schedule 12d by inserting all information relating to the **electricity distribution services** supplied by the **EDB** in relation to each **sub-network** for the **disclosure years** provided for in the report.	This information is included in Appendix B
2.7	*EXPLANATORY NOTES TO DISCLOSED INFORMATION*	
2.7.2	Subject to clause 2.13.4, before the start of each **disclosure year**, every **EDB** must complete and **publicly disclose** the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	This information is included in Appendix B
2.9	*CERTIFICATES*	
2.9.1	Subject to clause 2.13.3, where an **EDB** is required to **publicly disclose** any information under clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2, the **EDB** must at that time **publicly disclose** a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 **directors** of the **EDB**.	A copy of the certificate is included in Appendix H
AMP design		
1.	The core elements of asset management— 1.1 A focus on measuring **network** performance, and managing the assets to achieve service targets; 1.2 Monitoring and continuously improving asset management practices; 1.3 Close alignment with corporate vision and strategy; 1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets; 1.5 That responsibilities and accountabilities for asset management are clearly assigned;	1.1 Chapter 2.3.4 provides an overview of our performance while chapter 4.6.4 discusses our service performance. 1.2 Recognition of the need to improve our asset management is identified in the Executive Summary. Our asset management capabilities, including a discussion regarding our AMMAT assessment and asset management improvement areas, are further discussed in chapter 7. 1.3 Chapter 4 details corporate strategy and governance and how that aligns with our corporate vision and strategy.

	REGULATORY REQUIREMENTS	AMP REFERENCE
	1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets; 1.7 An emphasis on optimising asset utilisation and performance; 1.8 That a total life cycle approach should be taken to asset management; 1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	1.4 Chapter 4 details our business strategies and objectives, their relationship to our asset management practices and our service performance (including objectives and targets). 1.5 Chapter 2.1.2 discusses our ownership and governance structures and 2.1.3 our governance roles and responsibilities. Chapter 4.7 details our asset management governance structures. 1.6 Chapter 3 provides an overview of our network assets, while chapter 5 provides further detail on each of our fleets. 1.8 Chapter 5 explains our approach to managing our asset fleets, and sets out our fleet plans, taking a total lifecycle approach. 1.9 Chapter 6.4.3 sets out our approach to non-network solutions.
2.	The disclosure requirements are designed to produce AMPs that— 2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1; 2.2 Are clearly documented and made available to all stakeholders; 2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the EDB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets; 2.4 Specifically support the achievement of disclosed service level targets; 2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment; 2.6 Consider the mechanics of delivery including resourcing; 2.7 Consider the organisational structure and capability necessary to deliver the AMP; 2.8 Consider the organisational and contractor competencies and any training requirements; 2.9 Consider the systems, integration and information management necessary to deliver the plans; 2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between EDBs; and 2.11 Promote continual improvements to asset management practices.	2.1 The elements of asset management identified in clause 1 are referenced above, while further elements are discussed throughout the AMP itself. 2.2 Our AMP is made available on our website to all stakeholders. 2.3 Our evaluation of our asset management processes is contained in Schedule 13 (Report on Asset Management Maturity). Asset management capability is discussed in chapter 7.1. 2.4 Chapter 4 discusses our service performance and supporting initiatives. Reliability initiatives are also discussed in Appendix C. 2.5 Chapter 5 discusses the condition, performance and risk for each individual fleet. Chapters 4.8 and 4.9 discuss risk management and resilience in general, while chapter 7.1.3 sets out our asset management development plan. 2.6 Service delivery is discussed in chapter 4.7.2 and works delivery in 4.7.3. 2.7 Governance roles and responsibilities are discussed in chapter 2.1.3 and further discussed in chapters 4 and 7. 2.8 Chapter 2.2.6 discusses our service providers and expectations and chapter 7.1.1 asset management capabilities. 2.9 Appendix E provides information on our supporting ICT systems. 2.10 We have included a glossary of terms in Appendix A. 2.11 Section 4.6 discusses asset management objectives and strategy and chapter 7.1 discusses our asset management capability, including our current asset management capability and asset management improvements areas.

REGULATORY REQUIREMENTS		AMP REFERENCE
Contents of the AMP		
3.	The **AMP** must include the following-	
	3.1 A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant;	3.1 The Executive Summary provides a brief overview of the contents and highlights information that we consider significant.
	3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes;	3.2 Chapter 2 provides a background to our asset management and planning processes, while chapter 4 discusses in detail our management strategy and governance approaches.
	3.3 A purpose statement which- 3.3.1 makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes; 3.3.2 states the corporate mission or vision as it relates to asset management; 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**; 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and 3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans;	3.3.1 Our purpose statement is contained in chapter 1.1 and chapter 1.1.1 details our AMP objectives. 3.3.2 Chapter 1.1.1 details our AMP objectives and chapter 4.4.1 discusses our vision, mission and values. 3.3.3 Chapter 1.1.1 and chapter 4.2. 3.3.4 Chapter 1.1.1 details our AMP objectives and chapter 4 discusses our strategic framework. 3.3.5 Chapter 1.1.1 details our AMP objectives and chapter 4 details our strategy and governance.
	3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed;	Chapter 1.1.2 details the period covered by the AMP.
	3.5 The date that it was approved by the **directors**;	Chapter 2.1.2 states the date on which the AMP was approved by Aurora Energy's board of directors.
	3.6 A description of stakeholder interests (owners, **consumers** etc) which identifies important stakeholders and indicates- 3.6.1 how the interests of stakeholders are identified 3.6.2 what these interests are; 3.6.3 how these interests are accommodated in asset management practices; and 3.6.4 how conflicting interests are managed;	3.6 Chapter 2.2 and 4.3 discuss our stakeholders. 3.6.1 Identification of stakeholder interests is discussed in chapter 4.3. 3.6.2 Stakeholder interests are detailed in chapter 4.3. 3.6.3 Chapter 4.3 discusses how stakeholder interests are accommodated. 3.6.4 Chapter 2.2 details how conflicts are managed.
	3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	3.7.1 Chapter 2.1.2 details our ownership and governance structure. 3.7.2 Chapter 2.1.2 details our ownership and governance structure.

REGULATORY REQUIREMENTS	AMP REFERENCE
3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**; 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	3.7.3 Chapter 4.7.2 discusses our service delivery, while chapter 4.7.3 discusses our works delivery.
3.8 All significant assumptions- 3.8.1 quantified where possible; 3.8.2 clearly identified in a manner that makes their significance understandable to interested **persons**, including- 3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business; 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and 3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	3.8.1 We comment on the possible impacts of certain assumptions (e.g. uptake on new technologies on demand forecasts), however these were not possible to quantify 3.8.2 Significant assumptions are discussed throughout the AMP, including in chapters 5, 6 and 8. Where possible they are clearly identified by the headings to the relevant section. 3.8.3 Not applicable. 3.8.4 Future reliability is discussed in the Executive Summary and uncertainty bands are provided for in relation to SAIDI and SAIFI. 3.8.5 Section 8.1.3 discusses inputs and assumptions underpinning our forecasts.
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	Data accuracy and the requirement for improved information management systems and data sets are discussed in chapter 7.
3.10 An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-* *(i) how the asset management strategy is consistent with the EDB's other strategy and policies;* *(ii) how the asset strategy takes into account the life cycle of the assets;* *(iii) the link between the asset management strategy and the AMP; and* *(iv) processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	Chapter 4.6 discusses our asset management strategy and objectives and chapter 5 our life cycle management of each of our fleets. Chapters 4.2, and 4.4 to 4.6 discuss our strategic framework, our corporate strategy and asset management policy. Chapter 4.1 provides an overview of our asset management system. The link between asset management strategy and the AMP is discussed in chapter 4.2. Chapter 4.2 discusses our strategic framework and chapter 4.7 details the processes that we have in place in terms of asset management governance.
3.11 An overview of systems and information management data;	An overview is provided in chapter 7.3 with further information contained in Appendix E.

REGULATORY REQUIREMENTS		AMP REFERENCE
	To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- *(i) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;* *(ii) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;* *(iii) the systems and controls to ensure the quality and accuracy of asset management information; and* *(iv) the extent to which these systems, processes and controls are integrated.*	Chapter 7.3 provides an overview of our ICT requirements and discusses our ICT governance, strategy and planning and ICT assets. Asset management systems are discussed in chapter 7.3.5 and further in Appendix E. Systems and controls are discuss in Appendix E.
3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	ICT investment in relation to asset management data is discussed in chapter 7.3.5 and limitations and initiatives to improve data are discuss in Appendix E.
3.13	A description of the processes used within the **EDB** for- 3.13.1 managing routine asset inspections and **network** maintenance; 3.13.2 planning and implementing **network** development projects; and 3.13.3 measuring **network** performance;	3.13.1 Chapter 5.2 details our operations and maintenance approach in terms of fleet management. Maintenance approaches for each fleet are discussed in more detail in chapter 5.3. 3.13.2 Our approach to developing our network is discussed in chapter 6. 3.13.3 Performance is discussed in chapter 4.
3.14	An overview of asset management documentation, controls and review processes. *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-* *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system;* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system.*	Chapter 4 discusses our strategy and governance, in particular chapter 4.2 which discusses strategic framework and chapter 4.7 which discusses our asset management governance.
3.15	An overview of communication and participation processes;	Chapter 2 details our relationship with our stakeholders and customers and chapter 4.6.3 further discusses community and stakeholder interaction.

REGULATORY REQUIREMENTS			AMP REFERENCE
		To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* *(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	Chapters 2.2, 2.3 and 4.3 discuss our interactions with stakeholders. Chapter 2.1.3 details our governance roles and responsibilities and 2.2.7 further discusses our staff.
	3.16	The **AMP** must present all financial values in **constant price** New Zealand dollars except where specified otherwise; and	This is stated in box 8.1.
	3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	The structure of the AMP is detailed in chapter 1.2.
Assets covered			
4.	The **AMP** must provide details of the assets covered, including-		An overview of assets is included in chapter 3.7, with more detailed fleet information contained in chapter 5.
	4.1	a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including- 4.1.1 the region(s) covered; 4.1.2 identification of large **consumers** that have a significant impact on **network** operations or asset management priorities; 4.1.3 description of the load characteristics for different parts of the **network**; 4.1.4 peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any.	4.1 Service areas are discussed in chapter 3. 4.1.1 The regions covered by our network are discussed in chapter 3, in particular chapter 3.5 and 3.6. 4.1.2 Major customers are discussed in chapters 3.5.2 and 3.6.2. 4.1.3 Load characteristics are discussed in chapters 3.5.1 and 3.6.1 4.1.4 Detailed in Chapters 3 and 6.
	4.2	a description of the **network** configuration, including- 4.2.1 identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings;	4.2.1 This information is set out in chapter 3. 4.2.2 Chapter 3 describes our subtransmission network. The capacity and security ratings of individual zone substations is set out in chapter 6.3. 4.2.3 Chapter 3 describes our distribution network. 4.2.4 An overview is provided in chapter 5.8. 4.2.5 Chapter 3 describes our low voltage network. 4.2.6 An overview of secondary systems is provided in chapter 5.10. Chapter 3 includes network maps and a single line diagram.

REGULATORY REQUIREMENTS		AMP REFERENCE
	4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the **network**'s distribution substation arrangements; 4.2.5 a description of the **low voltage network** including the extent to which it is underground; and 4.2.6 an overview of **secondary assets** such as protection relays, ripple injection systems, SCADA and telecommunications systems. *To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.*	
	4.3 If **sub-networks** exist, the **network** configuration information referred to in clause 4.2 must be disclosed for each **sub-network**.	Refer to 4.2 above.
	Network assets by category	
	4.4 The **AMP** must describe the **network** assets by providing the following information for each asset category- 4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	4.4 Network assets are detailed in chapters 3 and 5. 4.4.1 These are provided, where relevant, in chapter 5. 4.4.2 An overview of network assets is provided in chapter 3.7, with chapter 5 providing a more detailed description for each fleet. 4.4.3 These are described individually for each fleet in chapter 5. 4.4.4 These are described individually for each fleet in chapter 5.
	4.5 The asset categories discussed in clause 4.4 should include at least the following- 4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); 4.5.2 assets owned by the **EDB** but installed at bulk electricity supply points owned by others; 4.5.3 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.4 other generation plant owned by the **EDB**.	4.5.1 Chapter 5 discusses our fleets individually, with a fleet reference provided in chapter 5.3. 4.5.2 This is discussed in chapter 3.3. 4.5.3 Mobile substations are discussed in chapter 5.9. 4.5.4 Not applicable.
Service Levels		
5.	The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	Chapter 4 sets out our performance indicators and targets.

REGULATORY REQUIREMENTS		AMP REFERENCE
6.	Performance indicators for which targets have been defined in clause 5 must include **SAIDI values** and **SAIFI values** for the next 5 **disclosure years**.	These are set out in chapter 4.6.4.
7.	Performance indicators for which targets have been defined in clause 5 should also include- 7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types; and 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	7.1 These are discussed in chapter 4.6.2. 7.2 Service performance is discussed in chapter 4.6.4.
8.	The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	Chapter 4.6 discusses our performance targets and strategies.
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Chapter 4 provides information about historic performance.
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance. *Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.*	Forecast expenditure is detailed in chapter 8 and service level forecasts in chapter 4.
Network Development Planning		
11.	**AMP**s must provide a detailed description of **network** development plans, including—	Network development is discussed in chapter 6.
	11.1 A description of the planning criteria and assumptions for **network** development;	Our planning process is discussed in chapter 6.2.1 and key planning assumptions and inputs in chapter 6.2.2.
	11.2 Planning criteria for **network** developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Our planning process is discussed in chapter 6.2.1.
	11.3 A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;	This is addressed in chapter 6.2 and decision making governance structures are detailed in chapter 4.7.
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; and 11.4.2 the approach used to identify standard designs;	
	11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**;	Network development planning is discussed in chapter 6.2, options analysis is discussed in chapter 6.4 and capex is discussed in chapter 8.2.

REGULATORY REQUIREMENTS	AMP REFERENCE
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**; *The criteria described should relate to the EDB's philosophy in managing planning risks.*	Chapter 6.3 discusses the investment drivers, including system demand. Network and asset planning in terms of asset risk management are discussed in chapter 4.8.4.
11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision;	Chapter 6.5.1 discusses solution prioritisation.
11.8 Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the **zone substation** level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives;	11.8 System demand is discussed, and demand forecasts are provided, in chapter 6.3.1. 11.8.1 The method used for load forecasting is set out in chapter 6.3.1. 11.8.2 Load forecasting is set out in chapter 6.3.1. 11.8.3 Network constraints are discussed in chapter 6.3.1. 11.8.4 Distributed generation is discussed in chapter 3.4 and demand management in chapter 6.4.3
11.9 Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and 11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment;	Major projects are discussed in Section 6.5 and Appendix F
11.10 A description and identification of the **network** development programme including **distributed generation** and non-network solutions and actions to be taken, including associated expenditure projections. The **network** development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	Network development is discussed in Chapter 6, with related projects also being covered in Appendix F

REGULATORY REQUIREMENTS		AMP REFERENCE
	11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**; *For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options 2010502.1 should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.*	
	11.11 A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on **network** development plans must also be stated; and	Distributed generation is discussed in chapter 3.4.
	11.12 A description of the **EDB**'s policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address **network** problems or constraints.	11.12 Non-network solutions are discussed in chapter 6.4.3.
Lifecycle Asset Management Planning (Maintenance and Renewal)		
12.	The **AMP** must provide a detailed description of the lifecycle asset management processes, including—	Our lifecycle management approach is discussed in chapter 5.
	12.1 The key drivers for maintenance planning and assumptions;	These are discussed in chapter 5.1.
	12.2 Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**;	12.2.1 and 12.2.2 Chapter 5 provides this information for each fleet individually. 12.2.3 A capex summary is provided for in chapter 8.2.
	12.3 Identification of **asset replacement and renewal** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	12.3 Refurbishment and renewal is discussed in chapter 5.2.2 and furthermore in chapter 5 for each fleet individually. 12.3.1 Chapter 5 provides this information for each fleet individually. 12.3.2 Non-network solutions are discussed in chapter 6.4.3.

REGULATORY REQUIREMENTS		AMP REFERENCE
	12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the **network** and the optimum use of existing **network** assets; 12.3.2 a description of innovations that have deferred asset replacements; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**; and	12.3.3 to 12.3.5 These are discussed in chapter 6.5
	12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Chapter 5 provides this information for each fleet individually.
<u>Non-Network Development, Maintenance and Renewal</u>		
13.	**AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including—	
	13.1 a description of **non-network assets**;	13.1 Chapter 7 details our non-network assets.
	13.2 development, maintenance and renewal policies that cover them;	13.2 Chapter 7.3.3 details our ICT strategy and planning.
	13.3 a description of material **capital expenditure** projects (where known) planned for the next five years; and	13.3 This is discussed in chapters 7.3.3 and 8.2.6.
	13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	13.4 This is discussed in chapter 7.3.3.
<u>Risk Management</u>		
14.	**AMP**s must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events; 14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and 14.4 Details of emergency response and contingency plans. *Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need*	14.1 Risk management and resilience are discussed in chapters 4.8 and 4.9. 14.2 and 14.3 High impact low probability events are discussed in chapter 4.9. 14.4 Emergency procedures and plans are discussed in chapter 4.9.4. Risk management and resilience are discussed in chapters 4.8 and 4.9.

REGULATORY REQUIREMENTS			AMP REFERENCE
		for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.	
Evaluation of performance			
15.	**AMP**s must provide details of performance measurement, evaluation, and improvement, including—		
	15.1	A review of progress against plan, both physical and financial; *referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;* *commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced; and* *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	Chapter 4.6 discusses performance.
	15.2	An evaluation and comparison of actual service level performance against targeted performance; *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	Appendix C discusses our reliability performance, our primary service performance measure
	15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the **EDB**'s asset management and planning processes.	Chapter 7.1.2
	15.4	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	Chapter 4.6 discusses performance.
Capability to deliver			
16.	**AMPs** must describe the processes used by the **EDB** to ensure that- 16.1 The **AMP** is realistic and the objectives set out in the plan can be achieved; and 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the **AMP** plans.		16.1 Chapter 4 discusses our objectives, strategy and governance practices. 16.2 An overview of our ownership and governance structure is included in chapter 2.1 along with governance roles and responsibilities. Chapter 4 details further our approach to strategy and governance, including in particular the processes and procedures in place relating to asset management governance. Chapter 7 discusses the functions and assets that support our asset management activities.

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H. DIRECTOR CERTIFICATE

Certification for Year-beginning Disclosures

Pursuant to Clause 2.9.1 of Section 2.9

We Stephen Richard Thompson and Margaret Patricia Devlin, being directors of Aurora Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge::

a) The following attached information of Aurora Energy Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, and 12d are based on objective and reasonable assumptions which both align with Aurora Energy Limited's corporate vision and strategy and are documented in retained records.

Director	Director
17 October 2018	17 October 2018
Date	Date

17 October 2018