
Asset Management Plan

APRIL 2013 – MARCH 2023

Asset Management Plan No. 20
A 10 Year Management Plan for Aurora Energy Limited
From 1 April 2013 to 31 March 2023

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**Plan prepared for Aurora Energy Ltd
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This issue approved by Aurora Board of Directors
March 2013



ISO 9001

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1 Executive Summary

1.1 Background and Objectives

1.1.1 Key Business Activity, Goals & Objectives

Aurora's key business activity is the management and delivery of electricity to approximately 82,908 consumers within Dunedin and Central Otago. To do this, Aurora manages and maintains a range of assets including 513km of sub-transmission lines, 36 zone substations, 2260km of high voltage line, 904km of high voltage cable, 6677 distribution transformers and 1,863km of low voltage distribution, plus a variety of other electrical infrastructure including street lighting. Together, these assets have a total replacement cost of approximately \$653M.

Aurora's mission is to be the best performing infrastructural business in New Zealand. To achieve this, our objectives focus on managing our assets prudently to ensure that the supply and distribution of electricity is secure, reliable and affordable; service levels are met and maintained; service delivery is safe; and investment is financially sustainable over the short, medium and long-term.

1.1.2 Purpose of AMP

Aurora faces many challenges and issues when trying to achieve key activity objectives and must do so whilst also ensuring the interests and expectations of stakeholders are met alongside regulatory compliance requirements. We continually work to find the most appropriate balance between performance, risk and cost over the life-time of assets managed. Aurora's Asset Management Plan (AMP) documents this approach by outlining the asset management processes and practices used to develop optimised lifecycle management strategies. Our AMP is therefore a vital component of our planning process that demonstrates how we address multivariate requirements by integrating management, financial and technical practices to deliver the strategies and initiatives planned for our electricity assets. This AMP demonstrates how Aurora intends to meet key goals and objectives, looking ahead 10 years from April 2013. Mandatory information disclosure requirements, as determined by the Commerce Commission, are also incorporated into the structure and content of this AMP.

1.1.3 Stakeholders

Aurora recognises that a key asset management function is to understand who our stakeholders are, what they value and why. This information helps to determine the Levels of Service (LoS) stakeholders require (or expect) and associated willingness to pay.

Our key stakeholders are:

- Customers and Consumers
- Shareholder - Dunedin City Holdings Ltd.
- Employees
- Board Members
- Retailers
- Distributed Generators
- Contractors
- Government Agencies; Commerce Commission
- Transpower
- General Public
- Other stakeholders (developers, landowners, property investors)

We have identified our stakeholder interests through communication relating to contractual arrangements, use-of-system agreements, submissions, surveys, board meetings. These interests are considered as part of our assessment of asset management drivers and accommodated through our asset management strategies where appropriate.

If a specific conflict between stakeholder interests is identified then we will adopt an appropriate conflict resolution process to suit the issue and stakeholder concerns.

Over the coming year, a review of stakeholder needs and values is planned in order to ensure that that our service levels and performance targets are still appropriate and align with the expectations for the services being delivered.

1.1.4 Asset Management Drivers and Planning Assumptions

Aurora faces some potentially challenging issues in both the short and long term that may impact on key activities and functions. These issues represent challenges and policy choices that must be addressed in order for the

activity to achieve its key objectives. These challenges manifest themselves through a variety of external and internal drivers that can be grouped under the following aspects:

- Stakeholder Expectations
- Standards and Legislation
- Industry Structure and Governance
- Environmental Issues and Natural Hazards
- Affordability and Financial Sustainability
- Population and Demand Trends
- Ageing Infrastructure

Our shareholder, Dunedin City Holdings Limited, expects Aurora to achieve the economic, social and cultural objectives specified in our Statement of Intent, with financial strength and sustainability being key. Our consumers consider that price (cost) is more important than quality, but do not want to pay less if it means impacting upon quality (e.g. more interruptions). Our regulators require more transparency in how we manage our business and our contractors seek surety with respect to continuity of work. Territorial authorities want to ensure communities of business continuity during times of civil emergency and seek evidence that our knowledge and management of network risk for lifelines planning is robust. Our relationship with Transpower is an important aspect of this as is coordination of network development programmes. Regular and timely communication underpins all of the above.

Our planning assumptions acknowledge the aging network in Dunedin and the growth patterns in Central Otago. It is assumed that Dunedin's growth is likely to remain relatively static and that growth in Central is likely to continue; but that the driver for this growth in some parts may be through irrigation needs as opposed to residential development. It is assumed that this situation creates some specific challenges, with the potential for stranded infrastructure, limitations on affordability of service improvements, and increasing maintenance required of the existing infrastructure.

Aurora is equally cognisant of the potential impact that climate change may have on weather patterns and the risks these may pose to network reliability and operability; as such, these aspects are considered as part of the network development planning process. It is also assumed that the push for affordability and financial sustainability will continue. For Aurora, this means that optimisation is a critical consideration towards maintaining the levels of service we are committed to meeting within current budget.

Over the coming year, further review and consideration will be given to network risk and criticality alongside the current decision-making criteria, assumptions and prioritisation methodology in order to provide greater transparency on decisions relating to network development projects.

1.1.5 Accountabilities & Responsibilities

Aurora must address a variety of expectations whilst also ensuring budgets and timeframes are met. To do this, Aurora ensures a robust management framework is in place for those accountable and responsible for asset management, ranging from General Managers through to Contracting Teams. Aurora has contracted asset management to Delta under a performance-related contract. Under this contract, Delta is required to meet defined objectives by delivering on specific targets for network performance and customer service, as well as the provision of detailed development plans covering periods during and beyond the contract period. Overall management of Aurora's network assets is undertaken at Dunedin and Cromwell offices. Ultimately, Aurora's Board of Directors is the overall body responsible for all decision-making within the company. The asset management structure for our electricity assets is illustrated in Figure 2.3.

1.1.6 Asset Management Policy and Process

Aurora's asset management policy recognises that effective asset management requires an appropriate and practical balance between performance, risk and cost throughout the lifecycle of all assets; as well as ensuring continuous improvement in asset management functions and capabilities to achieve key outcomes and objectives.

Aurora's asset management practices are driven by commitments to Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial sustainability; underpinned by Continuous Improvement. Our integrated approach to asset management is illustrated in Figure 2.4.

We are committed to achieving alignment with best practice asset management that is fit-for-purpose and will implement appropriate asset management systems to govern the planning, investment, operation, maintenance and disposal of assets.

A robust risk framework will be used to identify and manage our risks and we will continue to improve the information we have on our assets in order to improve the planning and prioritisation of investment. In conjunction with this, Aurora will work to ensure that associated funding requirements are well planned, based on reliable information, with the impact of costs spread evenly over time. The importance of people and process cannot be

understated and Aurora recognises that investment in training and development is critical to achieving business objectives.

1.1.7 Asset Management Systems and Information

Several systems and processes contribute to the management of Aurora's assets for network planning, maintenance programming, operational requirements, financial monitoring and performance measurement. These include GIS, SCADA, SAP, Gentrack to name a few.

In 2012, Aurora commenced a review of the master asset data within the GIS along with review of the practices associated with the management and maintenance of the data. As a result, some initial changes to process and practice has occurred to ensure the asset records are more complete and accurate.

Notwithstanding the good progress being made to improve the completeness and confidence in asset data, Aurora faces significant challenges in the areas of asset and works management. Many of the current asset management business processes and systems are supported by manual, paper-based environments. These provide substantial barriers to both the efficient capture of data and the easy access to and processing of relevant data to create business intelligence and knowledge.

Developments in the information, communication and technology sector (ICT) provide opportunity for Aurora to consider introduction for increased levels of intelligence and performance. Emergent and proven technologies, coupled with decreasing relative technology costs, provide economically viable opportunities to better enable and support more efficient and effective asset management. Smart, easy to use and cost effective solutions will be tested in terms of their ability to enable and support. See Section 7 for further detail on improvements in this area for Aurora.

1.2 Service Levels and Performance

Aurora's levels of service have been developed in response to the asset management drivers outlined in the previous sections, as well as evaluation of past performance. Aurora monitors performance and measures success against specific targets for each of the service levels.

Aurora's performance for 2011/2012

The table below shows Aurora's service levels, associated measures, targets and results for 2011/2012 as well as targets for 2012/13 and the 5 year average forecast. Aurora has complied with nearly all of its performance targets for 2012, with the exception of the 'unplanned' quality threshold targets (SAIDI, SAIFI and CAIDI¹); overhead network faults and loss ratio. Excluding planned shutdowns, the main causes of outages over both years were due to equipment deterioration, tree contact and weather. Of the 484 unplanned interruptions on the network in 2011/12, approximately 73% were restored within 3 hours. The number of proven voltage complaints has continuously complied with target levels, however this metric has increased over the last three years.

Section 3.2 provides a full evaluation of performance including a benchmark comparison with the industry.

Appendix A.1 contains schedules on forecast interruptions and durations.

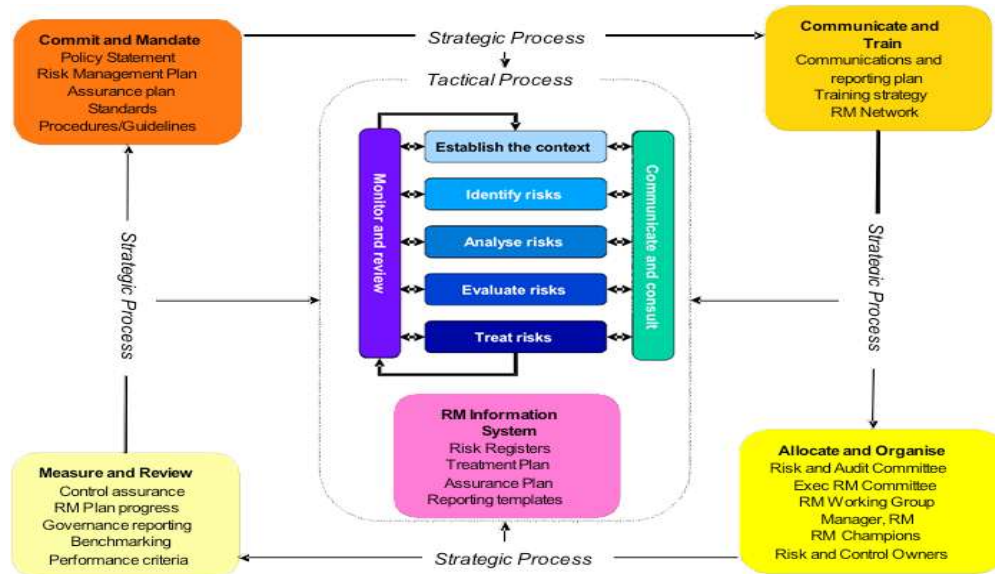
¹ SAIDI – System Average Interruption Duration Index; SAIFI – System Average Interruption Frequency Index; CAIDI – Customer Average Interruption Duration Index.

Service Criteria	Performance Indicator	Target (2011/12)	Actual (2011/12)	Targets (2012/13)	Avg Annual (2013-2017)
Safety					
Safety of public	No. of incidents per year	0	0	0	0
Safety of personnel	No. of incidents per year	0	0	0	0
Safety of network assets	Compliance with standards	Compliance	C	Compliance	Compliance
Reliability / Quality					
Network Reliability	SAIDI (Planned)	15.0	13.4	14.0	13.6
	SAIDI (Unplanned)	71.0	102.5	70.0	68.4
	TOTAL	86.0	115.9	84.0	82.0
	SAIFI (Unplanned)	1.27	1.67	1.27	1.24
Faults per 100 km HV	No. per year	11.4	11.2	10.5	10.4
Faults per 100 km HV UG	No. per year	2.50	2.35	2.5	2.5
Faults per 100 km HV OH	No. per year	13.5	15.13	13.5	13.5
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	4.0	<10	<10
Network Restoration	CAIDI (unplanned)	55	77.9	55	55
Responsiveness					
Restore supply following general network failure	Within 4 hours of notification (Dunedin)	<4	73% restoration within 3 hours	<4hrs	<4hrs
	Within 4 hours of notification in urban areas (Central)	<4		<4hrs	<4hrs
	Within 6 hours of notification in rural areas (Central)	<6		<6hrs	<6hrs
			Valid claims	Valid claims	Valid claims
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	-	0	0	0
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	-	0	0	0
Notification of planned service interruption	Missing notification of planned interruption	-	1	0	0
Efficiency					
Load factor (%)	Energy into network/peak kW hours per year	≥ 52%	53%	54%	54%
Loss ratio (%)	Energy into network less energy delivered / energy into network	≤ 6%	6.4%	6%	6%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	≥ 30%	32.9%	30%	30%
Environmental / Compliance					
SF6	No. of incidents per year	0	0	0	0
PCBs	No. of incidents per year	0	0	0	0
Oil spills	No. of incidents per year	0	0	0	0

1.3 Risk Management

Aurora recognises risk management and asset management are inextricably linked. The risk management framework and practice being applied by Aurora is based on the AS/NZS ISO 31000:2009 risk management standard. The following diagram illustrates the risk management framework and process being applied.

Risks to Aurora are linked to safety (staff, contractors, public), reliability, quality, natural hazards, compliance, commercial, reputation, resources and so on. Aurora refers to the 'four R's approach - Reduction, Readiness, Response and Recovery – to assist with business continuity planning and manage network resilience.



This AMP identifies the main network and business risks for Aurora and the actions being taken to address these. These both inform (and are informed by) Aurora's approach to life-cycle management and network development. Some of the main areas of focus are:

Risks relating to safety and hazards - in response to recommendations from the Royal Commission for changes to the building legislation, more comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out. Outputs from this will contribute to the development of a long term programme of works, which will be incorporated into Aurora's 2014/15 AMP.

Wooden poles have also been identified as a priority area. In particular, the number of condition 0 poles (poor condition) on the network is a concern for Aurora and focus is being placed on addressing this risk through a project to improve the quality of condition data. This will, in-turn, assist with targeted and prioritised renewal programmes.

Risks relating to age and obsolescence have driven a thorough review of Auroras SCADA, control, communication and protection systems. Outputs from this will contribute to the development of a long term programme of works, which will be incorporated into Aurora's 2014/15 AMP.

Risks relating to capacity in the short-medium term (based on predicted demands against firm load capacity) are associated with the Cromwell, Frankton and Halfway Bush Grid Exit Point (GXP) supply areas. Of particular focus for Aurora is the Upper Clutha Valley sub-transmission network, within the Cromwell GXP area; particularly if the Tarras irrigation scheme goes ahead.

Risks relating to network reliability and legislative compliance are also directing focus towards better vegetation management. Under the Electricity (Hazard from Trees) Regulations 2003, Aurora must attend to the vegetation with a rating of 0 (bad) without delay. There are currently 6,059 condition 0 areas that require cutting, with estimated cost in the tens of millions. A significant portion of Aurora's planned maintenance budget has been spent on vegetation management annually to date. Anecdotal evidence suggests there has been a positive improvement in network reliability due to this spend, although more time is required to see real trends.

Oil-filled distribution switchgear and gas-filled sub transmission cables are also a focus. Throughout 2013/14 Aurora will continue to develop its asset health indices and risk-based frameworks to inform and prioritise capital expenditure programmes and will continue to work on business continuity planning.

Further detail on the projects underway to address risk is outlined in the lifecycle and network development sections of this plan.

1.4 Lifecycle Asset Management

The life cycle management section of this AMP supplements the network development plan. It details the actions and expenditure necessary for maintaining and operating Auroras assets, covering planned maintenance, reactive

maintenance, renewal and capital replacement. Planned maintenance is time and condition-based; reactive maintenance covers fault and emergency situations and replacement (upgrade or renewal) occurs when maintenance is no longer cost-effective or other drivers (e.g. system growth) warrant new investment in the network.

For 2013/14, Aurora will be focussing on reviewing and revising asset management strategies and plans to address some of the risks identified. Attention will be given to transformers, switchgear, poles, cables and link boxes amongst others. Vegetation management is also a key issue for Aurora and we will continue to work with our contractors to find the most effective way to manage process and costs.

Aging assets are of particular concern in the Dunedin network, with some assets being over 100 years old and many assets between 60-80 years; as such, focus is also being placed on refining renewals forecasts to determine the level of funding required versus that which is practically sustainable over the long term.

While parts of the central network are also aging, one of the main issues for Aurora in this area is ensuring our network policies and practices are adhered to by external contractors working on the network, recognising that workmanship and installation can significantly impact the lifecycle costs of our assets. This includes addressing the need for standardisation across assets and designs to promote efficiency and minimise risk.

The table below summarises the value of Aurora's assets by category (based on the information provided for the Electricity Distribution (Information Disclosure) Requirements). Information on asset quantities and their general condition is detailed further in Section 5 as well as Appendix A.2.

Asset Category	RC	% by \$
Subtransmission	\$56,225,175	8.6%
Zone substations	\$106,405,460	16.3%
Distribution and LV lines	\$138,766,783	21.3%
Distribution and LV cables	\$193,748,491	29.7%
Distribution substations and transformers	\$97,288,303	14.9%
Distribution switchgear	\$54,025,963	8.3%
Other	\$6,466,821	1.0%
Total (rounded)	\$652,927,000	100%

1.5 Network Development

Aurora recognises that expenditure can be driven by a variety of factors and we are committed to continually improving our understanding of the strategic and operational challenges that drive investment needs. The network development plan provided in this AMP outlines the investment required to maintain, enhance and develop the operating capability of Aurora's system. It details the expansion and upgrading considered necessary to accommodate predicted future network loading; and projects to address risk, reliability, safety and compliance.

A range of factors are used to assess the viability of development projects, including (but not limited to) compliance with safety design standards, security of supply, quality, capacity, economic analysis/capital return. Prioritisation of programmes and projects is linked to Aurora's key activity objectives and associated service level attributes.

Major projects over the planning period include several substation upgrades in both Dunedin and Central. Significant investment is also being made on Dunedin's sub-transmission network over the next 10 years, with six sets of 33kV underground cables being replaced at an estimated cost upward of \$17 million dollars.

Demand for irrigation in Central Otago is influencing load on the network and significant investment will be required if the potential demand becomes reality. A significant amount of time has already been spent on scoping a variety of options to ensure system growth can be catered for in this area.

Section 6 and Appendix A.3 provide further detail on demand projections, future capacity and network development.

1.6 Financials

A summary of our forecast capital and operational/maintenance expenditure is shown. Detail behind the drivers for this expenditure is provided in Sections 5, 6 and Appendix A.4. Changes from previous forecasts are further detailed within this plan and comments are provided on the variance between actual spend against budget for the 2011/12 year.

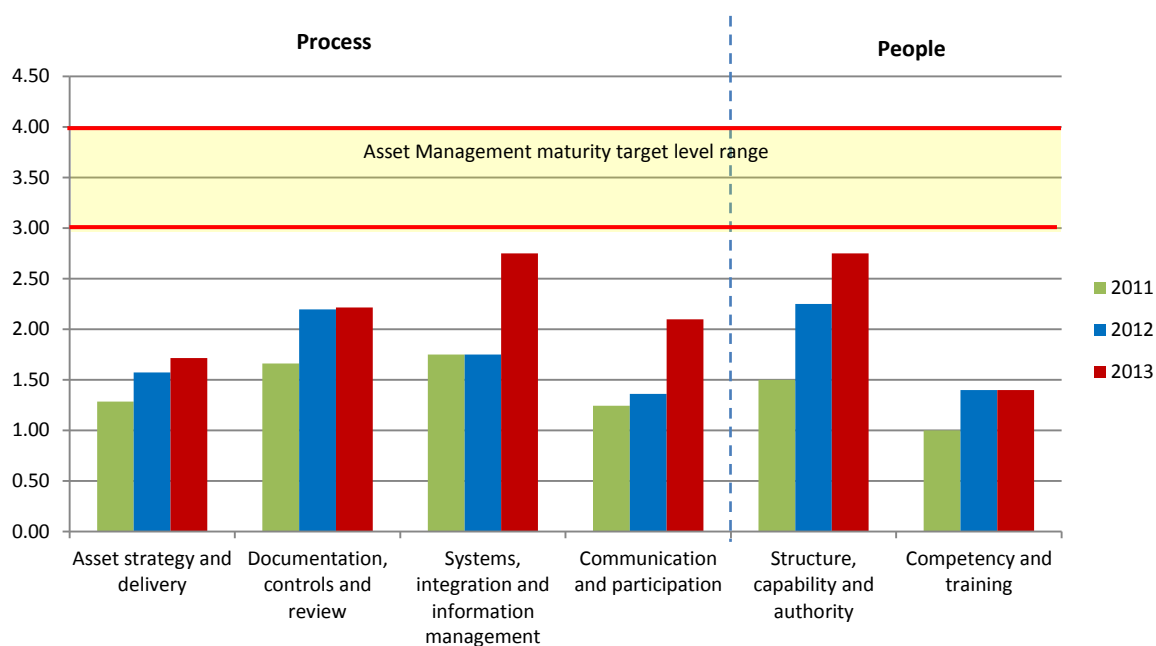
(\$000)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
O & M Expenditure	9,822	10,068	10,319	10,577	10,842	11,113	11,390	11,675	11,967	12,266
Capital Expenditure	26,682	26,965	30,813	22,127	21,632	20,157	21,128	26,887	14,759	14,786
TOTAL	36,504	37,033	41,132	32,704	32,474	31,270	32,518	38,562	26,726	27,052

1.7 Improvement Planning

Aurora recognises that asset management is as much about people and process as it is about investment in the network for physical asset improvements. It is important for Aurora to ensure that asset management practice is aligned with best practice and is always 'forward-looking' when it comes to improvement in practices and standards. An Asset Management Improvement Programme (AMIP) is being implemented and is based on the internationally accepted PAS55 standards, utilising the International Infrastructure Management Manual (IIMM) as a guiding document. The improvement programme covers 'process', 'people' and 'metric' aspects based on the Commerce Commissions assessment framework (Asset Management Maturity Assessment Tool or AMMAT).

'Process and people' improvements relate to how Aurora carries out asset management across the range of functional areas, plus the associated capabilities and competencies for achieving asset management objectives. 'Metric' improvements relate specifically to achievement of service levels (asset and customer) and performance targets.

The graph below shows the maturity assessment results to date. This illustrates there have been steady improvements made across all aspects of Aurora's asset management since the initial baseline assessment was carried out in 2011.



Asset Management Maturity Assessment results (2011-2013)

The areas that have shown greatest improvement are:

- systems and information management
- structure and capabilities
- communication/participation

It is clear that these results demonstrate the effects of a targeted strategy for asset management improvement within Aurora's asset management service providers, Delta.

The areas that will be receiving attention in 2013/14 are:

- asset strategy and delivery
- competency and training
- documentation, controls and review
- asset systems and information will continue to be refined.

Appendix F provides the full assessment report on Asset Management Maturity as per the Commerce Commission schedule requirements.

2 Background and Objectives

2.1 Business Activity, Goals & Objectives

Aurora's key business activity is the management and delivery of electricity within two distinct networks in Dunedin and Central Otago; and a small area in Te Anau (see Figure 2.1). Aurora's electricity network begins downstream of Transpower's transmission Grid Exit Points (GXP's). The Dunedin network is supplied from two GXP's, being South Dunedin and Halfway Bush. The Central network is supplied from three GXP's being Clyde and Cromwell and Frankton. Aurora also manages a small embedded network in Te Anau (connected to The Power Company network, installed in 2005).

Specifically, Aurora manages and maintains: 513km of sub-transmission lines, 36 zone substations, 2260km of high voltage line, 904km of high voltage cable, 6677 distribution transformers and 1,863km of low voltage distribution, plus a variety of other electrical infrastructure including street lighting. Together, these assets have a total replacement cost of approximately \$653M. This makes Aurora the 6th largest electricity distribution business (EDB) in New Zealand delivering approximately 1,392 GWh of electricity to homes and businesses annually, with a total of over 130MW of distributed generation connection to the network.

The objectives of Aurora's activity are to ensure that the supply of electricity is secure, reliable and affordable; service levels are met and maintained; service delivery is safe and investment is financially sustainable over the short, medium and long-term for more than 82,000 consumers within Dunedin and Central Otago. Aurora must balance and align these with the principal corporate goal being to operate a successful business to achieve the economic, social and cultural objectives as outlined in the Statement of Intent.

This Asset Management Plan (AMP) sets out Aurora's framework for addressing these needs through a robust approach to asset management and subsequent service delivery.

2.2 Purpose of AMP

The AMP illustrates how Aurora intends to achieve its objectives by outlining the strategies, objectives, policies, plans and systems adopted for the efficient management of its electricity distribution networks.

Overall, the AMP demonstrates an integrated framework for asset management which ensures that Aurora:

- understands the main external and internal drivers that influence asset management and planning;
- understands stakeholder interests; consumer needs and expectations;
- understands network performance i.e. what network capacity, reliability and security of supply is required, both now and in the future to meet service level targets;
- sets service levels that will meet asset performance requirements balanced with consumer, community and regulatory requirements;
- has adequately considered the classes of risk Aurora's network business faces, and that Aurora has systematic processes in place to mitigate identified risks;
- has robust and transparent processes in place for managing all phases of the network life cycle, with emphasis on optimising asset utilisation and performance;
- has an ever-increasing knowledge of Aurora's asset locations, ages, conditions, and likely future behaviour;
- makes all decisions within systematic frameworks and guidelines;
- maintains a culture of continuous improvement in asset management.

The main AMP objectives are shown in Table 2.1 along with comments on how the objectives translate into practice.

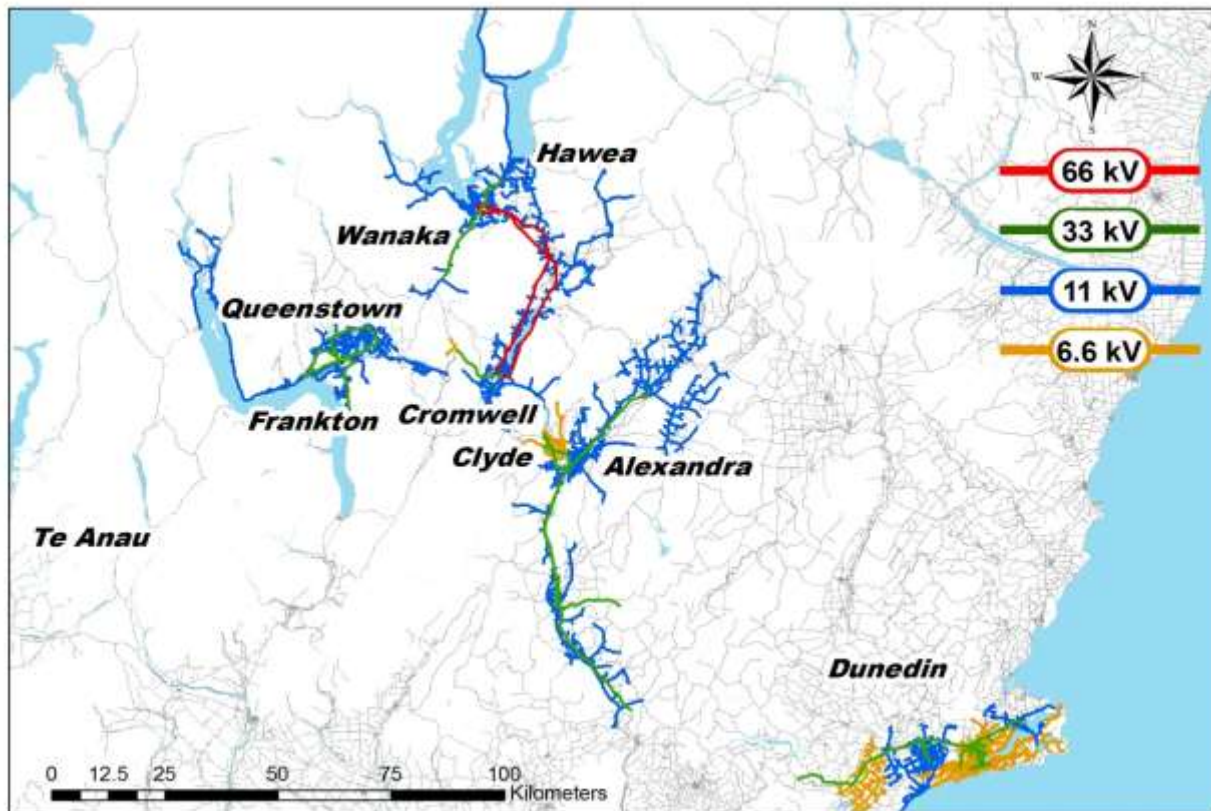


Figure 2.1 - The Aurora Network

Table 2.1 - AMP Objectives

Asset Management Plan objectives	What does it mean?
Defines: AM Objectives & Service levels to be provided. Targets/performance measures that Aurora aims to achieve & how service delivery will be monitored.	AM strategies & actions reflect the expectations of stakeholders, including customers. Progress will be tracked to determine if commitments are being achieved.
Translates: Strategic goals and organisational objectives into AM strategies and action plans	There is a link between corporate strategy and management of network assets
Describes: Planning assumptions and uncertainties. Risks associated with Aurora's network business. Risks of not meeting business and AM objectives.	Understand what network capacity, reliability and security of supply is required, both now and in the future, and what issues drive these requirements. Appropriate risk management practices form an integral part of normal business activities
Identifies: Forward works programmes required to: - meet agreed service levels, - address replacement/renewal needs, - cater for future growth, - address risk Cost estimates for delivering these programmes. Actions that enhance management performance & ensure continuous improvements.	That capital expenditure decisions are prudent and represent value to customers Asset replacement & network augmentation is undertaken with appropriate timing. Ensure that long-term functionality and value of assets is maintained. Operational efficiency and performance improvements.
Demonstrates: Responsible management of the network infrastructure. That funds are optimally applied to deliver cost-effective services that meet expectations.	AM strategies support revenue requirements and deliver a reasonable profit, in keeping with both shareholder expectations and regulatory constraints. An 'optimal life cycle' approach is taken to managing network assets.
Documents: Current AM practices used by Aurora re: policies, objectives, strategies, plans and systems adopted for the efficient management of its electricity distribution networks.	Decisions are made with systematic frameworks and guidelines. That robust and transparent processes in place for managing all phases of the network life cycle.
Achieves: Compliance with regulatory and legislative requirements Best practice asset management (for the level of AM deemed appropriate for the organisation).	Electricity Distribution (Information Disclosure) Requirements 2012 are met. Best practice in managing the balance of performance, risk and cost is achieved. Established continuous improvement philosophy (process and people).

Corporate Business Processes and Asset Management Planning

Aurora's mission is to be the best performing infrastructural business in New Zealand. The Strategic Plan has identified asset management as a fundamental component for achieving the company's strategic objectives.

Figure 2.2 illustrates the cascade from Aurora's mission statement through to the AMP and provides context for how the different documented plans and business processes relate to one another and influence asset management, along with other external drivers such as the regulatory environment.



Figure 2.2 - Corporate Business Processes and Asset management Planning

2.3 Accountabilities, Responsibilities and Stakeholder Interests

2.3.1 Accountabilities and Responsibilities

Aurora has contracted asset management to Delta under a performance-related contract that was renewed for a further 10 years on 1 July 2007. Under this contract Delta is required to:

- deliver annually specified network performance and customer service, subject to significant financial penalty for non-performance;
- deliver detailed development plans covering periods during and beyond the contract period.

Up until the latter part of 2011, asset management was carried out by the Engineering Services and Network Services Managers who, together with the Aurora Commercial Manager, formed the Network Management group within Delta.

Changes to this structure since 2011 has seen the establishment of a specific Asset Management business unit, consisting of five core teams: Asset Management, Infrastructure Performance, Asset Systems, Delivery and Commercial; reporting to the General Manager for Asset Management. The General Manager for Asset Management reports to the Aurora board, along with the CEO. The Board reviews and authorises the AMP from which annual and 5 yearly budgets are set. Reports on significant projects are provided to the Board on a monthly basis, including regular reporting of KPI's and related asset management objectives.

Figure 2.3 details the accountabilities and responsibilities for asset management within the Aurora/Delta contract. Under this contract, the responsibility for the management of the network is primarily through Delta's Chief Executive, the General Manager Asset Management, and Managers within the Asset Management business unit. Table 2.2 provides more detail on actual responsibilities.

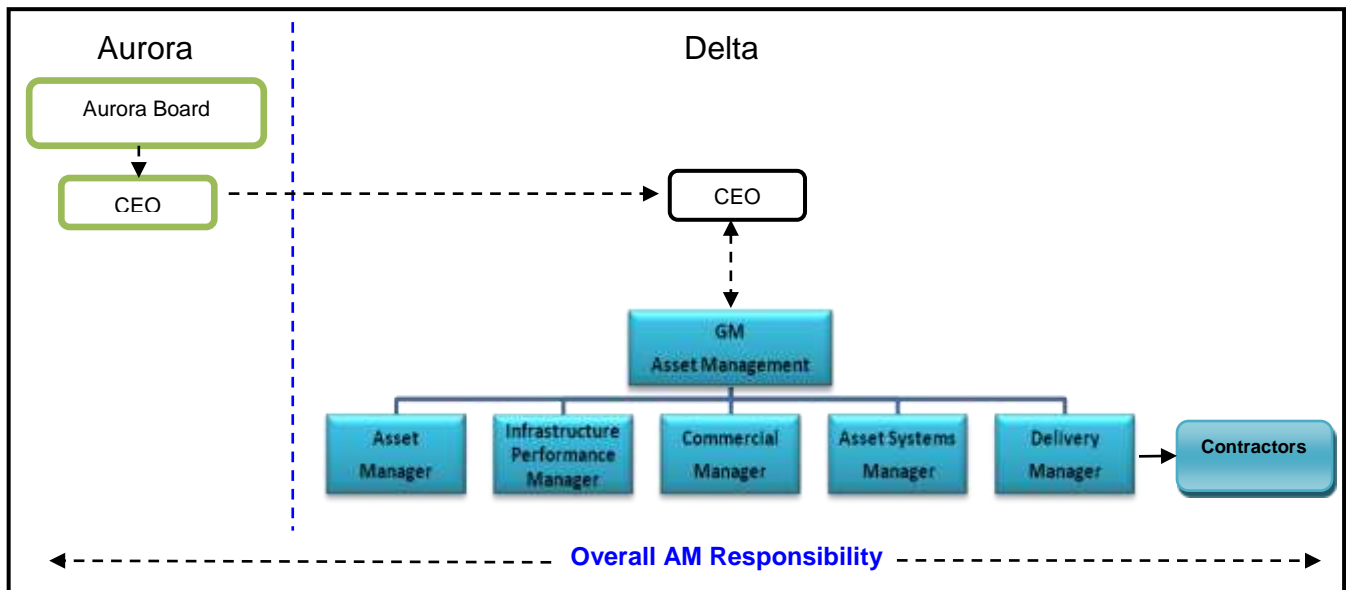


Figure 2.3 - Asset Management Accountabilities and Responsibilities

Table 2.2 - Delta's Accountabilities and Responsibilities for Asset Management

Title	Responsibilities
Aurora Board	Overall governance and decision-making for Aurora. Receives and reviews regular and special reports from Delta, and meets monthly to review a range of operational indicators and to consider strategic issues. Capital programme approval. Consideration of business risks.
CEO & GM Asset Management	Primary responsibility for management of the network. Preparation of regular and special reports to the Aurora Board, including the AMP and detailed development plans. Reports to the Board include financial reporting, capital expenditure, energy and system demands, outage summaries, and specific reports of all outages over 0.5 SAIDI minutes.
Asset Manager	Ensuring a high quality Asset Management Plan is prepared and completed in line with industry best practice and meets necessary disclosure requirements. Development, documentation and improvement of the policy and processes of Delta's asset management methods. Development of the capital, operational and renewal expenditure programme; and implementation of strategies that extract optimal value, and mitigates risk exposure, over the lifetime of the portfolio of assets under ownership or management.
Infrastructure Performance Manager	Manage forecasting, analysis and design to ensure that security and reliability levels are maintained over the lifetime of managed assets. Carry out network investigations and risk assessment to inform planning and investment requirements and strategies. Develop concept and detailed designs for capital, operational and renewal expenditure programmes. Public Safety and Risk Management.
Delivery Manager	Responsible for efficient project and contract management to deliver the annual works programme - including new capital, renewals and maintenance projects. Accountable to ensure delivery of projects within approved budget, time and quality constraints – ensuring co-ordination and timely communication with contracting and operations, as well as relationship management and development of contractor standards.
Asset Systems Manager	To enable and support integrated asset management through the development and implementation of an integrated asset management system including system control operations, ensuring quality data capture systems, information and data accuracy and management; in order to support strategic asset decision making and work management systems. Adding value to processes, systems and thinking through the creation of knowledge and intelligence.
Commercial Manager	Manages Aurora's contracts with energy retailers and directly connected consumers, Transpower, distributed generators, embedded network owners, use-of-system pricing policies, regulatory matters, the billing of line charges and outage management. Maintains overview on regulatory requirements.
Internal Contracting Team	To deliver works associated with the annual operational, maintenance, capital replacement and network development programmes as required by the Delivery Manager.
External Contractors and Consultants	As and when necessary, external contractors and consultants are used for works associated with the annual operational, maintenance, capital replacement and network development programmes.

2.3.2 Stakeholder Interests

Aurora recognises that a key asset management function is to understand who our stakeholders are, what they value and why. Stakeholders are defined as groups or individuals with either a direct or indirect interest in Aurora's network asset management policies and practices. Table 2.3 summarises Aurora's main stakeholders and their interests. This table illustrates some of the issues Aurora takes into account, but is not exhaustive.

Where stakeholder conflict arises, Aurora applies certain criteria, with safety being the primary concern. Other criteria include: reliability/cost trade off, economic growth, environmental responsibility, legislative compliance. Ultimately, the Aurora Board will decide upon the most appropriate way to resolve any significant issue of conflict between stakeholder interests. Aurora also ensures alignment is maintained with Electricity and Gas Complaints Commission scheme requirements (see Section 3.1.4 for further detail).

It is clear that there are different service expectations across the range of Aurora's stakeholders. It is important for Aurora to have a clear understanding of these as they help to inform on the levels of service stakeholders require (or expect) and associated willingness to pay. Also see Section 2.6.2 regarding communication and participation.

Aurora uses surveys, open requests for feedback, safety reviews, industry forums and other means (such as internal review workshops) to identify interests. A series of actions have commenced as part of Aurora's AMIP for reviewing Aurora's service levels. The intent of these actions is three-fold: (i) to evaluate current knowledge on Aurora's stakeholder base; (ii) review whether Aurora's service level commitments are still relevant and appropriate; and (iii) identify how Aurora may better communicate with all relevant parties in the future. This is to be supplemented with a concurrent review of service level performance measures and associated monitoring.

Table 2.3 – Stakeholder Interests

Stakeholder	Interest	How Stakeholder Interests are Identified
Shareholder	Adequate, stable, and secure return on investment Good corporate citizenship	Board meetings
Contractors who provide services to Aurora	Contractual relationship Safe working environment Continuity of work	Contractual requirements
Electrical Contractors who work for consumers and developers	New-connection policies Maintenance and upgrade policies	Contractual requirements Quality documentation feedback
Electricity Consumers	Line charges Network reliability/service quality Optimisation of electrical losses New-connection policies	Consumer satisfaction surveys Direct liaison re issues such as no power, trees, etc Safety advertising
Electricity Retailers, and distributed generators	Line charges Network reliability/service quality Contractual arrangements Optimisation of electrical losses	Use-of-System Agreements
Employees of Delta (main Contractor)	Health and safety Creative work environment Career opportunities	Internal communications
Government / Regulator	Economic efficiency Compliance with statutory requirements	Submissions Relationship meetings
Landowners with network facilities on their land	Safety Easement conditions Access for maintenance/repair Compensation for significant interference	Direct communication and consultation
Property developers	New-connection policies Timely network expansion	Direct communication
Territorial authority	Minimising of environmental impacts (RMA) Local economic development Control of assets in road reserve Conversion of overhead to under-ground	Direct communication Submissions RMA Applications

Stakeholder	Interest	How Stakeholder Interests are Identified
NZ Transport Agency	Control of assets in road reserve Safety issues such as hedges on Aurora-owned land	Direct communication
Transpower	Reliability of supply Investment for growth	Direct communication re planning System operator communication
Media	News, background information	Direct communication

2.4 Asset Management Drivers and Planning Assumptions

Aurora faces some potentially challenging issues in both the short and long term that may impact on key activities and functions. These issues represent challenges and policy choices that must be addressed in order for the activity to achieve its key objectives. These challenges manifest themselves through a variety of external and internal drivers that influence Aurora's asset management practices, priorities and decision-making. These drivers are inextricably linked to principles defined in the Asset Management policy (see Section 2.5) and can be grouped under the following; and are discussed below.

- Stakeholder Expectations
- Standards and Legislation
- Industry Structure and Governance
- Environmental Issues and Natural Hazards
- Affordability and Financial Sustainability
- Population and Demand Trends
- Ageing Infrastructure

Stakeholder Expectations

Heightened stakeholder awareness and service level expectations mean that better corporate responsibility is required for sustainably managing resources and monitoring impacts of Aurora's activities. Such interests may include increased expectations for the right to a quality service (timely, efficient, low-cost); less acceptance of anything otherwise (i.e. 'status-quo' is no longer considered as an acceptable option); and tension between affordability and service level expectations from different regions and also different sections of the community.

Given the above, Aurora is committed to providing a broad range of service levels for all stakeholders. These service levels cover aspects such as safety, capacity, continuity of supply, restoration of supply, efficiency, compliance and environmental responsibility. Stakeholder interests are accommodated by considering these within the decision-making framework for asset management investment and service delivery. Refer to Section 2.3.2 for further details on stakeholder interests.

Legislation and Standards

Aurora aims to achieve material compliance with all relevant legislation, regulations, standards and codes of practice that relate to how the electricity distribution network is managed and maintained, including any relevant environmental legislation. Associated documentation includes, but is not limited to:

- Electricity Act (1992)
- Electricity Industry Act (2010)
- Electricity (Safety) Regulations (2010)
- Electricity (Hazards from Trees) Regulations 2003
- Commerce Act (1986) (*incl Electricity Information Disclosure Requirements*)
- Civil Defence and Emergency Management Act (2002)
- Local Government Act (2002)
- Resource Management Act (1991)
- Building Act (2004)
- Public Works Act (1981)
- Health and Safety in Employment Act (1992)
- Health and Safety Regulations (various)
- NZ Electrical Codes of Practice

Central Government regularly amends or develops legislation, regulations, standards and policies. Examples include the Emissions Trading Scheme (ETS), Resource Management Act (RMA) and the Electricity Industry Act. Such reviews have either a direct or indirect effect on how Aurora may manage and maintain its electricity assets. For example, Central Governments' response to climate change may indirectly influence Aurora's network regarding the changing types and quantities of distributed generation² and recommendations from the Royal Commission report into earthquake-prone buildings and seismic strengthening are likely to lead to changes in building legislation. Such requirements are already driving the need for Aurora to allocate expenditure to its structural assets (e.g. zone substation buildings). Aurora must also comply with technical standards set by regulation, such as minimum and maximum voltage set by regulation for the protection of consumer appliances.

At a regional and local level, Aurora's network spans three territorial authority areas, being: Dunedin City, Central Otago and Queenstown Lakes; contained within one regional authority boundary (Otago Regional Council). Council planning requirements set out minimum standards for local land use and development. In some cases these requirements impact on the location, appearance and housing of Aurora's above-ground assets; in other cases assets are required to be located underground. Aurora also refers to local authority planning information on potential short, medium and long-term growth on the distribution network. Relevant aspects of this with respect to Aurora's development plan are discussed further in Section 6.

Industry Structure and Governance

The structure of the New Zealand electricity sector has undergone significant reform over the last 10-20 years. Aurora is one of many local distribution companies at the end of an industry 'chain', comprising of generators; a wholesale electricity market; transmission; electricity users and retailers. As such, Aurora is continually faced with the challenge of ensuring an appropriate balance between price and quality for electricity consumers, whilst restraining the impacts from any costs that may be passed on from the upstream aforementioned entities.

Aurora is subject to regulation under Part 4 of the Commerce Act 1986, for price-quality and information disclosure. Price-quality regulation is designed to ensure that EDBs have similar incentives and pressures to suppliers operating in competitive markets to innovate, invest and improve their efficiency. As such, Aurora is required to provide an audited self-assessment to the Commerce Commission against the DPP on an annual basis. Whether non-compliance of such requirements will be met with increasing regulatory force is still somewhat uncertain, however Aurora will continue to position itself to respond appropriately to any regulatory situation.

Aurora also provides a disclosure statement (performance statement) on an annual basis which contains information related to asset management and other measures such as financial statements, through to technical measures such as transformer utilisation.

The complete derivation of the compliance measures are included in the Information Disclosure and the Default Price-Quality Path Compliance Statements published annually on Aurora's website www.auroraenergy.co.nz.

Affordability and Financial Sustainability

Although parts of the global economy have shown some signs of recovery following the recent period of recession, obstacles to economic growth continue through the economic side effects of the European sovereign debt crisis, accompanied with slowing economic growth in the United States and China. The continued constraints on international, national, regional and community growth and development means that affordability is likely to be at the forefront of decision-making for some time yet.

The ability for Aurora to manage costs and debt over the short, medium and long term is crucial and may significantly influence the amount of funding available for infrastructure investment. Currently, there are several large projects either in progress or being planned for over the next 10 years. However, those in the initial stages of scoping/appraisal are still subject to funding approval. Where funding does become available for such projects, it is imperative that its use is clearly justified. Aurora is working to further develop robust capital and maintenance programmes to ensure on-going life-cycle costs are estimated correctly and can be sustained in the future.

Along with budget limits and growth, the levels of service provided by Aurora may be constrained due to the actual cost of infrastructure as well as historic under-investment. Aurora intends to pursue a reduction in unnecessary

² For example, the National Policy Statement for Renewable Electricity Generation (2011) contains provisions for small and community scale renewable electricity generation activities into Regional Policy Statements and Regional/District Plans.

operational and maintenance cost by working to implement optimised solutions; supplemented by working towards more standardised assets and designs where appropriate.

Environmental Issues

Peak Oil

There is growing concern that global oil prices will rise dramatically once 'easy to reach' deposits have become scarce and demand for oil outstrips supply. The timing of this is still relatively unclear; as is how it may actually affect the management of Aurora's network. However, many predictions suggest that the global peak in oil production will occur in the next few years, with around 60% of oil producing countries having peaked already; this indicates that the price of oil is likely to continue to rise and become more volatile.

Potential consequences of peak oil include the use of electricity for transport as a substitute for fuel; as well as increased use of renewable energy sources such as solar, hydro, geothermal and tidal power. Renewable energy sources in New Zealand, particularly wind-based generation, have been growing in importance, reflecting improved technologies and the economics of rising electricity prices. At a local level, renewable options are also becoming more affordable for the "average" consumer. There has been a noticeable increase in the amount of distributed (embedded) generation connected to Aurora's network in 2012, and it is anticipated that this trend will continue.

Climate Change

There is increasing scientific certainty that the climate is changing on a global scale, which in-turn is reflected in changes to national, regional and local weather patterns. It is predicted that Otago's climate will become drier for extended periods, with increased mean temperatures and daily temperature extremes. Along with heavier (but less frequent) rainfall events, both areas may be subject to increased incidents of flooding and inundation resulting in asset damage. In particular, Dunedin may be at risk to the effects of sea level rise as it has significant areas of low-lying land, some of which is reclaimed. These areas may also experience increased fire risk with temperature increases; all with likely consequent increases to operational and maintenance requirements. Strong wind events also pose a significant risk to Aurora's assets. Overall, changes in weather patterns are acknowledged as one of the challenges faced by Aurora, particularly with respect to peak demand forecasting assumptions.

Natural Hazards

As alluded to above, the natural hazards that Aurora potentially faces in managing and maintaining the electricity distribution include: rain events, sea level rise, strong winds, fire, landslides & land creep, rockfall, erosion, snow/ice, undermining, tsunami, earthquake (and associated processes, particularly liquefaction).

The likelihood of a seismic event that Christchurch has experienced happening in Dunedin or Central Otago is not clearly understood at present. The consequences, however, are likely to be significant and potentially catastrophic. Accessibility to, and availability of, essential services provided by Aurora could be limited-to-none and could affect the provision basic needs, including other services such as water supply (i.e. dependency on electricity for conveying (pumping) drinking water).

Lessons from the Christchurch earthquake have been invaluable to a range of infrastructure providers located both inside and outside of the affected areas. Aurora will continue to build a better understanding of the potential impacts to its network from events of that nature and scale by collating as much relevant information as possible, including response and recovery demands plus associated costs. Aurora recognises that understanding our interdependencies with other utility providers, such as Transpower and Rounding Authorities, is fundamental for ensuring preparedness and business continuity in emergency situations. See section 4 for further detail.

Population and Demand Trends

Aurora's network feeds both high density urban loads (e.g. Dunedin; Queenstown) and diverse rural loads (e.g. Central Otago, but also some parts of the Dunedin network). Growth in demand for electricity can occur for several reasons, such as from an increase in population or the introduction of new end-use applications. Aurora's 5-year system maximum demand growth forecast for Dunedin is 0.6% p.a. and for Central is 2.6% p.a.

For Dunedin and Central, growth in demand has historically matched growth in population. However Central Otago has been more influenced by 'spurts' of localised demand, such as the property boom of the 2000's. Peak demands (in winter) are driven by school and public holidays, and associated ski field operations during these times. More recently, emerging irrigation requirements for more intensive farming is posing challenge in the Upper Clutha area. The government is also providing support for this type of activity announcing that that up to \$80 million has been earmarked for bridging finance for large-scale irrigation schemes in the next financial year. As such the impact of irrigation could become a dominant influencing factor on summer peak, which potentially may increase if hotter drier periods are more frequent. Conversely, for many rural parts of Aurora's network

(excluding Queenstown and Wanaka) the high cost of providing infrastructure has historically meant that additional capacity is not planned for, and only installed when needed.

Population for much of central Dunedin is forecast to remain relatively static and some areas expect population decline, although areas such as the Taieri Plains are experiencing some growth. Dunedin does not have the same economic drivers for assets or services that exist in places with, say, high levels of population growth. As such, any response to asset management drivers requires maximising the use of existing infrastructure wherever possible.

The above situation creates some specific challenges for Aurora asset management, with potential for stranded infrastructure, limitations on affordability of service improvements, and increasing maintenance required of the existing infrastructure. As a result, increasing emphasis is being placed on justifying investment requirements and the need to find system efficiencies.

Further detail on how growth and load forecasting is used for development planning is provided in Section 6.

Ageing Infrastructure

The nature of Dunedin's growth has meant that large quantities of network infrastructure were designed and built over a short timeframe, during periods of rapid population and industrial growth in the 19th century. As a result, the City contains a significant proportion of old and aging assets. As network assets reach the end of their useful life, their performance decreases.

Given the physical asset attributes of Dunedin's network, particularly the sub-transmission cables and critical zone substations, there is a risk of critical infrastructure failure. A key challenge across all of Aurora's asset categories is 'smoothing' the cost of associated upgrades and renewals, and to prioritise spend in areas where it will give the greatest benefits.

The network in Central Otago also has areas that are just as old as Dunedin, however more continuous growth has afforded an ability to upgrade over time. For example, much of Cromwell was rebuilt for the Clyde power station project of the late 1980's.

In response to the above, it is recognised that Aurora must place more focus on understanding network risk profiles including those assets which are most critical to maintaining the delivery of service; and using this information to drive pro-active condition assessment and maintenance practices. Asset information is critical to this and Aurora will continue to improve the information it has about its infrastructure in order to improve the planning and prioritisation of new capital and renewals.

2.4.1 Planning period and Uncertainties

This plan covers the 2013 - 2023 period. It is important to recognise that there is a degree of uncertainty associated with any future forecasts or predictions over such planning timeframes. The previous section covered generic assumptions and sources of uncertainty that are considered applicable to Aurora's development planning process.

The following underlying assumptions also need to be taken into account when referring to this AMP:

- Annual budgets relating to the management of Aurora's network are based on the estimates provided in the AMP, which is reviewed and refined on an annual basis. To this end, the AMP identifies asset management strategies and high-level requirements which inform (and are informed by) detailed investigations and development reports.
- Authorisation of expenditure comes from a two-phase process: (i) approval of the AMP capital and maintenance programmes by the Board of Directors; and (ii) subsequent specific approvals for projects identified in the annual programmes.

While it is intended to carry out the programme as planned, it must be acknowledged that circumstances may change and Aurora may, at a later date, decide to take different actions to those it currently intends to take (with the exception of for any statutory liability which cannot be excluded). It is acknowledged that unanticipated equipment failures, storms, natural disasters, or material changes in local loadings may require a change to the planned investment programme outlined in this plan.

In 2012 a review of the planning and forecasting criteria, assumptions and uncertainties relating to the Aurora electricity distribution networks commenced. The purpose of the review is to ensure that decisions remain aligned with the most recently available and reliable information. It is anticipated that Aurora's AMP's will continually refine these aspects as we seek to provide more transparency on:

- significant assumptions considered to have a material impact on forecast expenditure;
- the source and impacts of significant assumptions; and
- assumptions that have been made in relation to sources of uncertainty.

The Network Development plan in Section 6 provides further detail on the above points.

2.5 Asset Management Policy and Process

Given the drivers, assumptions and uncertainties outlined in the previous section, Aurora's asset management policy recognises that effective asset management requires an appropriate and practical balance between performance, risk and cost throughout the lifecycle of all assets; as well as ensuring continuous improvement in asset management functions and capabilities to achieve key outcomes and objectives.

Aurora is committed to achieving alignment with best practice asset management that is fit-for-purpose and will implement appropriate asset management systems to govern the planning, investment, operation, maintenance and disposal of assets.

Figure 2.4 provides an overall process diagram of the approach and framework for integrated asset management. Having an integrated approach is fundamental to delivering Aurora's asset management objectives.

Development of asset management processes and implementation of the proposed 'asset management system' (refer to Section 2.6) will assist to achieve a more systematic approach to asset management that links information together according to the process flow diagram.

A robust risk framework will be used to identify and manage risks and Aurora will continue to improve the information we have on our assets in order to improve the planning and prioritisation of new capital and renewals. In conjunction with this, Aurora will work to ensure that associated funding requirements are well planned, based on reliable information, with the impact of costs spread evenly over time. This will help to minimise the risk of declining service levels and control cost impacts.

Progress towards attaining advanced asset management continues in terms of alignment with best practice standards and guidelines, such as PAS55 and the International Infrastructure Management Manual. See Section 7 for further detail.

2.6 Asset Management Systems and Information

There are several systems and processes that contribute to the management of Aurora's network assets for network planning, maintenance programming, operational requirements, financial monitoring and performance measurement. The text that follows describes the function of each system.

Geospatial Information System (GIS): The GIS acts as a master asset register and network connectivity model. The geospatial model of Aurora's electricity network extends from the transmission GXP's to the customer connection points. The GIS also acts as a master register for other complementary data (e.g. the cadastre, topography, etc.).

The management and maintenance of GIS records relating to Aurora's assets is on-going. Updates and changes are triggered predominantly by the business processes associated with capital and maintenance activities such as inspections, assessments, failure response, renewals and augmentations. Such updates generally occur by direct input. Updates and changes to other GIS records are triggered predominantly by the data owner and generally occur through systemic processing e.g. LINZ cadastre updates.

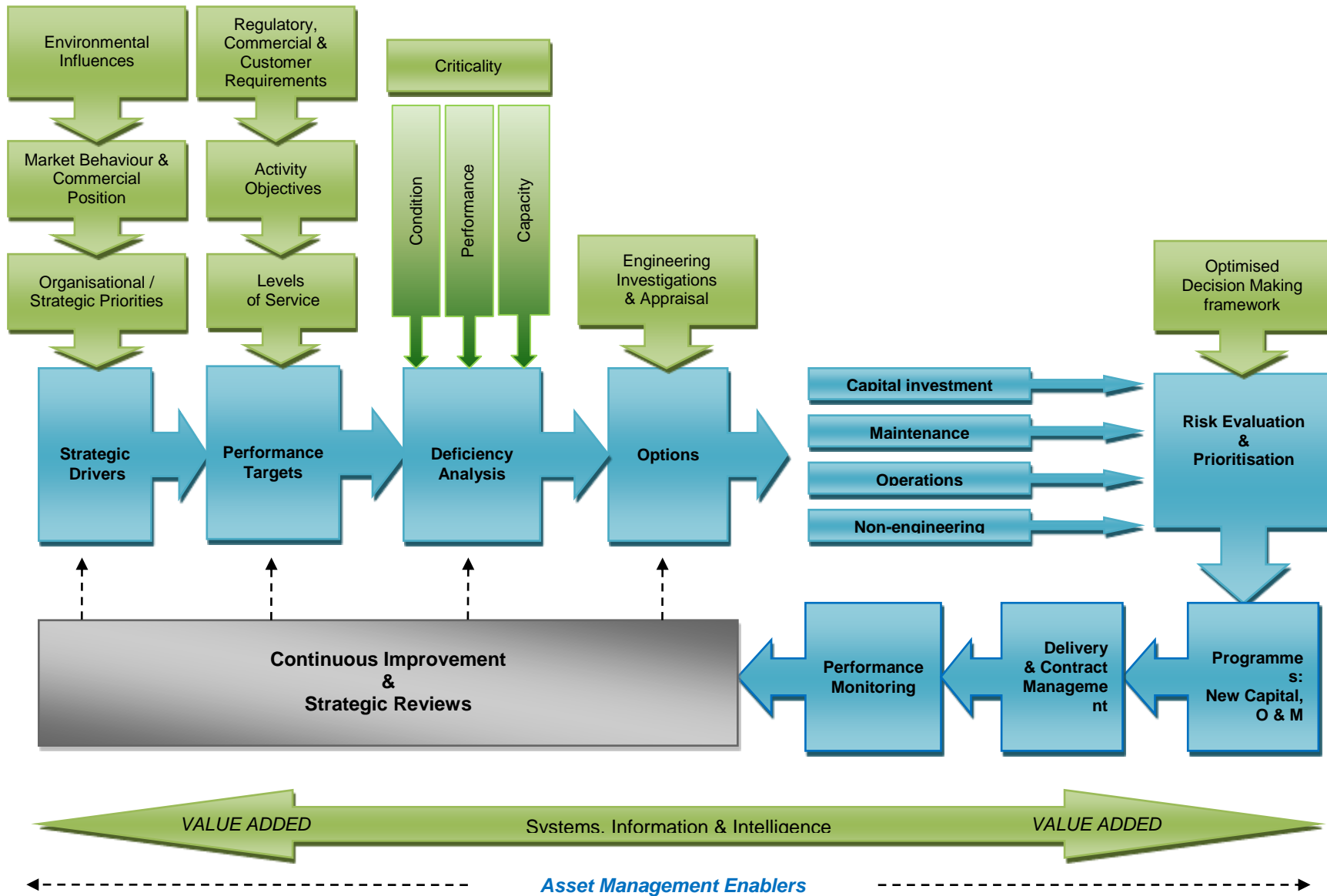


Figure 2.4 – Integrated Asset Management Framework

Network Connections Management: The process of negotiating and constructing new connections is electronically managed from application to liveness. This information is fed into a database called Gentrack. Gentrack software provides network billing, network tariff management, network connection management, and meter asset tracking in an integrated package. Gentrack's ability to manage a wide range of network tariffs, charges and billing methodologies, coupled with interfaces to the electricity market registry, enables Aurora to automate a number of key network billing activities including; retailer file validation, market registry integration, fixed and variable tariff management, bill reversals, and network reconciliation.

A proposal to up-grade Gentrack was approved in August 2012 and is expected to be completed by June 2013. The principal drivers for upgrading the system include declining ability to support the legacy version, better integration with other financial and asset management systems, improved reporting and analysis, and compliance with new Electricity Industry Participation Code Part 10, which comes into effect in June 2013.

Financial, Work Order & Contract Management: The issue of work to (and inspection of by) contractors is managed electronically within the SAP accounting software. The SAP system covers contract recording, reporting, costing, inventory control, estimating and quoting, contract and trade debtors, plant costing, creditors / general ledger, cashbook and fixed assets. Detailed monthly financial reports are produced as well as variance reports to monitor performance.

Maintenance Programming and Management: Storage and analysis of maintenance histories for specific plant items and for asset classes allows optimisation of maintenance and replacement at both class and item levels. Software such as Microsoft Project and Excel is used in conjunction with SAP to produce maintenance programmes.

Network Monitoring System (SCADA), Load Control and Outage Management: Aurora's monitoring, control, communication, protection and automation systems provide the electricity network with the key information and control capabilities that Aurora needs to operate. Load data, (demand and total energy), is collected and analysed for growth trend information and the outage management system is used for planning and notification of outages and production of interruption statistics. Most of these systems are running 7 days, 24 hours continuously and have been used extensively for network operation, safety control, equipment protection, outage management and decision making. A comprehensive review of these systems has been carried out and upgrade proposals are discussed in Sections 5 and 6.

Fleet Management: Aurora's asset management contractor, Delta, is trialling a GPS fleet management systems (Smartrak) that provides a number of reporting features including real time vehicle location, activity reporting, job allocation, integration with job management and customer service requests, location of fixed assets, route optimisation, driver behaviour and a suite of powerful reports that can be configured to meet specific needs.

Quality/Business Management System: A structured framework for managing the existing business systems and quality documentation is being implemented in 2013.

2.6.1 Asset Information and Data Confidence

In 2012, Aurora commenced a review of the master asset data within the GIS along with review of the practices associated with the management and maintenance of the data. As a result, some initial changes to process and practice has occurred to ensure the asset records are more complete and accurate. The approach to (and outcomes from) the most current review are exemplified in Table 2.4, which shows a data confidence description and associated rating with respect to completeness and accuracy. These are being reconfigured to align with the Commerce Commission confidence ratings as part of information disclosure requirements.

Table 2.4 – Data completeness and Accuracy assessment

		Regular data audits & verification of data received					Occasional data audits & verification of data received					Regular data audits & verification of data received					Occasional data audits & verification of data received				
		Documented properly & recognised as best method of assessment					Minor shortcomings (e.g. some data extrapolation or assumption applied)					Documented properly & recognised as best method of assessment					Minor shortcomings (e.g. some data extrapolation or assumption applied)				
		Data based on sound records, procedures, investigations & analysis					Data records, procedures & analysis incomplete or unsupported					Data based on sound records, procedures, investigations & analysis					Data records, procedures & analysis incomplete or unsupported				
		1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5
		Highly Reliable	Reliable	Uncertain	Very Uncertain	Unknown	Highly Reliable	Reliable	Uncertain	Very Uncertain	Unknown	Highly Reliable	Reliable	Uncertain	Very Uncertain	Unknown	Highly Reliable	Reliable	Uncertain	Very Uncertain	Unknown
		100% to 95%	90% to 80%	75% to 60%	60% to 15%	10% to 0%	100% to 95%	90% to 80%	75% to 60%	60% to 15%	10% to 0%	100% to 95%	90% to 80%	75% to 60%	60% to 15%	10% to 0%	100% to 95%	90% to 80%	75% to 60%	60% to 15%	10% to 0%
		% Completeness	% Accuracy +/-																		
Asset Class																					
Poles, Support Structures, Concrete/Steel	Material																				
	Age																				
	Condition																				
	Performance																				
	Location																				
	Capacity																				
	Criticality																				
	Remaining Life																				
Quantity 19,833																					
Poles, Support Structures, Wood	Material																				
	Age																				
	Condition																				
	Performance																				
	Location																				
	Capacity																				
	Criticality																				
	Remaining Life																				
Quantity 33,392																					
Poles, Support Structures, Other	Material																				
	Age																				
	Condition																				
	Performance																				
	Location																				
	Capacity																				
	Criticality																				
	Remaining Life																				
Quantity 537																					

Issues and Challenges

Notwithstanding the good progress being made to improve the completeness and confidence in asset data, Aurora faces significant challenges in the areas of asset and works management. Many of the current asset management business processes and systems are supported by manual, paper-based environments. These provide substantial barriers to both the efficient capture of data and the easy access to and processing of relevant data to create business intelligence and knowledge.

The key issues noted during a review in 2012 were:

- **Advanced asset management.** Aurora's current asset management systems reflect a traditional asset management paradigm. Ownership and management of assets require more targeted and risk-optimised investment and maintenance decisions. This will require new tools and practices.
- **Right information/Right Time.** Asset management information needs to be easily accessible and reliable. Identification of key information gaps and challenges will provide a basis for prioritisation and timing of effort to address.
- **Integrated disciplined processes.** End-to-end business processes, workflows and dataflows need to be connected together to mitigate replication of data and unnecessary hand-offs. This will require standards and rule-based approaches to enable more efficient and effective practice.

Opportunities and improvements to address the issues and challenges are discussed in Section 7.

2.6.2 Asset Management Documentation, Controls and Review

Aurora has contracted asset management to Delta under a performance-related contract. Under this contract, Delta is required to meet defined objectives by delivering on specific targets for network performance and customer service, as well as the provision of detailed development plans covering periods during and beyond the contract period. External reviews and audits of selected aspects of asset management practice and process have been undertaken on a regular basis. Recent reviews include:

- 2005. All ground-mounted transformers were assessed for risk of vehicle impact and subsequent oil leak into a water way.
- 2007. Analysis and review of circuit breaker monitoring and maintenance procedures was initiated, and completed in August 2008, following a study of peer practices. This has resulted in an increased frequency of circuit breaker inspections.
- 2008. Analysis and review of pole inspection records, monitoring, and data capture procedures. This has identified data deficiencies. Improvements to condition data records continue.
- 2010. A review of structural adequacy of selected zone substation buildings was initiated and a review of the Value of Lost Load was initiated which resulted in adoption of the values in this AMP.
- 2011. Reviews of maintenance practices, engineering approach to risk and security of supply issues were completed. The conclusion is that the gas insulated subtransmission cables in Dunedin are fast approaching the end of their economic life has been reinforced by further site investigations. Structural checks have shown that one substation requires further earthquake strengthening.
- 2012. A review of asset management processes against PAS55 standards and IIMM guidelines.
- 2013. An audit of the PSMS and re-establishment of a quality management review team for asset management. An assessment of Auroras asset management maturity.

Aurora has processes and procedures documented to ensure non-compliance issues are addressed systematically, however the uptake and consistency of this process requires improvement. A review of the quality management system has been undertaken and a structured framework for managing the existing business systems and quality documentation is being implemented in 2013. See Appendix D for asset management quality control documentation and Section 7 for proposed improvements in asset management process and practice.

2.6.3 Communication and Participation

The communication of pertinent asset management information to and from employees and other stakeholders is improving; including appropriate top-down communication from Aurora's CEO. A series of presentations and workshops on various aspects of asset management have been held with staff and contractors throughout 2012 and these will continue as and when necessary (and in conjunction with the AMIP). Asset management requirements are well communicated to the financial function and communication to and from contractors is becoming more formalised and regular. Significant Transpower issues are both informally and formally reported to executive management as appropriate, and meetings are regularly held with Transpower to discuss both routine and emerging issues. Focus for 2013/14 will be clarifying and reinforcing asset management strategy, plan(s) and objectives; including better communication of the asset management policy, asset performance information, specific asset strategies and planning information to both staff and contractors. Also see Section 2.3.2 regarding stakeholder interests.

3 Service Levels and Performance

As discussed in Section 2, Aurora's activity objectives are to ensure that the supply/distribution of electricity is secure, reliable and affordable, service levels are met and maintained, service delivery is safe and investment is financially sustainable over the short, medium and long-term. The services provided by Aurora are driven by certain key principles or 'service attributes', being: Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial sustainability; underpinned by Continuous Improvement.

In order to monitor service delivered against requirements, values and expectations, Aurora surveys consumers, consults with stakeholders, and benchmarks against industry standards in order to ensure that Aurora:

- (i) meets commitments to service delivery and performance;
- (ii) understands customer values and level of service they require, and
- (iii) is aware of changing expectations.

There are also service levels that Aurora is required to uphold for various regulatory bodies, and to contribute to the overall well-being of the community. Section 2 identified Aurora's key stakeholders, consumer groups along with their interests in Aurora's service.

This section describes the consultation undertaken by Aurora, outlines the service levels and associated targets, presents performance results to date, and outlines justification for the levels of service provided. Financial performance is also discussed.

The service levels defined in this section can be categorised into customer, technical and financial; and are used to help Aurora:

- inform key stakeholders of current and proposed levels of service and associated performance targets;
- focus asset management objectives & strategies to deliver the required service levels;
- identify costs and benefits of the services
- enable customers to assess whether service levels meet needs and expectations;
- measure of the effectiveness of actions taken through monitoring and reporting on related performance measures.

3.1 Consumer Consultation

User opinion on quality, price and service issues is surveyed by Aurora on an annual basis through telephone surveys and postal surveys. The postal survey questions focus on price and quality (reliability). The telephone surveys cover other service-related issues such as restoration time and willingness to pay. Customers are selected at random for each survey.

3.1.1 Postal Surveys

Postal surveys commenced in 1999 and is continuous throughout the year (whereby 400 are sent out each month) so that:

- (i) results are less affected by long periods without supply interruption, or by significant interruption, at the time the survey is conducted with a given consumer; and
- (ii) results evolve with changes in network performance.

The results to date are presented in Figure 3.1 and show the majority of consumers are trending towards preference for a lower price rather than better quality of supply.

However recent results do show a slight change compared to the previous year with more people starting to show an interest in having better quality. Note that the response for the 2012/13 year is also shown (based on 8 months of data)

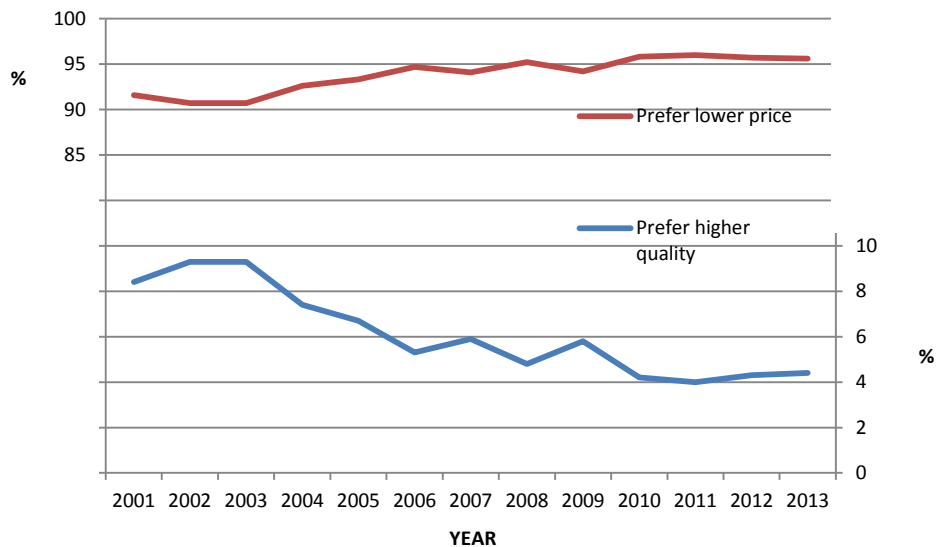


Figure 3.1 - Price Versus Quality Survey

3.1.2 Telephone Surveys

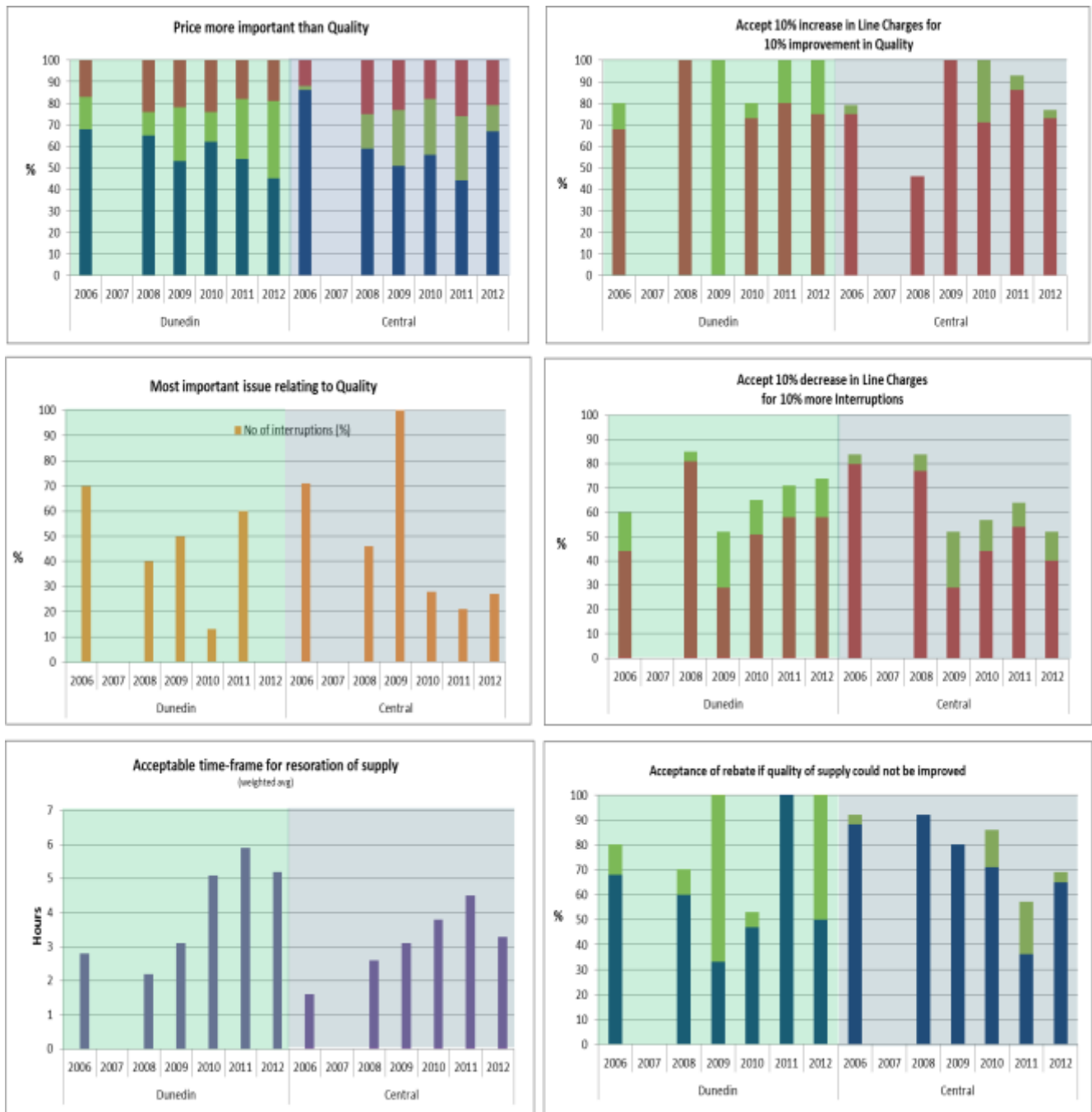
Aurora carries out annual telephone surveys of approximately 400 consumers, with 200 consumers from the Dunedin area and 200 from the Central Otago area. These consumers are selected at random, and the survey questions cover a range of price – quality and service related issues. The surveys commenced in 2006 and a sample of the results to date are presented in the graphs on the following page and in Table 3.1 below.

Table 3.1 - Results from Telephone Surveys (2006-2012)

No.	Question	Dunedin							Central						
		2006	2007	2008	2009	2010	2011	2012	2006	2007	2008	2009	2010	2011	2012
1	Price more important than quality														
	Yes (%)	68		65	53	62	54	45	86		59	51	56	44	67
	Unsure (%)	15		11	25	14	28	36	2		16	26	26	30	12
	No (%)	17		24	22	24	18	19	12		25	23	18	26	21
2	Single most important issue relating to quality														
	No of interruptions (%)	70		40	50	13	60	0	71		46	100	28	21	27
3	Accept 10% increase in line charges for 10% improvement in quality														
	No (%)	68		100	0	73	80	75	75		46	100	71	86	73
	Unsure (%)	12		0	100	7	20	25	4		0	0	29	7	4
4	Acceptance of rebate if quality of supply could not be improved														
	Yes (%)	68		60	33	47	100	50	88		92	80	71	36	65
	Unsure (%)	12		10	67	6	0	50	4		0	0	15	21	4
5	Accept 10% decrease in line charges for say 10% more interruptions														
	No (%)	44		81	29	51	58	58	80		77	29	44	54	40
	Unsure (%)	16		4	23	14	13	16	4		7	23	13	10	12
6	Acceptable time-frame for restoration of supply (weighted average)														
	(Hours)	2.8		2.2	3.1	5.1	5.9	5.2	1.6		2.6	3.1	3.8	4.5	3.3

KEY	(%)
YES	
UNSURE	
NO	

Results from Telephone Surveys



In summary the results indicate that:

Overall

- Consumers perceive price as being more important than quality, up until 2012 it appeared that there may have been a decreasing trend in this with it being of less importance, which also aligned with the results from the mail survey. However, 2012 results show a significant increase in the importance of price.
- A number of consumers are generally less willing to pay more for an improvement in quality (reliability), but at the same time do not want to pay less if it means there may be more interruptions.
- The 'number of interruptions' is perceived as the most important issue overall. However, the survey information also indicates that this may be declining in significance as the 'single most important' to

consumers compared to length of interruptions and voltage fluctuations. There are however points of difference (see comments below).

Dunedin vs Central

- With the exception of 2009, the most important issue relating to quality (number of interruptions) shows a decreasing trend in the Central area. Comparatively, this seems to be a more important issue in Dunedin.
- Historically, Central Otago respondents have consistently rated voltage fluctuations as the important issue relating to quality compared to Dunedin respondents. However Aurora's complaints register tells a different story, with a similar number of complaints regarding both number of interruptions and voltage fluctuations in Dunedin and Central.
- Consumers appear to be accepting a longer timeframe for restoration in both Dunedin and Central and this trend has been increasing since 2006, with a slight drop-off in 2012. However over the past 3 years the number of complaints received (recorded in the complaints register) is highest with respect to length of interruptions, so there could be some level of dissatisfaction with the service response being provided.
- Central consumers seem less tolerant of longer restoration times compared to Dunedin. This is also reflected in the complaints register whereby the number of complaints in relation to length of interruptions is higher in Central compared to Dunedin.

Suggestions for improvements contained within the surveys have indicated that consumers would like more communication (particularly for rural consumers) and for urban expectations are for an improved service in terms of responsiveness.

Note that the level of confidence associated with data and information gleaned from the surveys is considered to be uncertain largely due to limited sample sizes and the subjective views of respondents. See Section 2.3.2 on proposed improvements related to this.

3.1.3 Other Stakeholder consultation

Feedback from Electricity Retailers

From time to time, Aurora receives feedback from individual consumers, via their electricity retailer, on aspects of the Aurora delivery service. Based upon this feedback, Aurora is not aware of any systemic concerns with the level of reliability; notably Aurora's network reliability performance is below the industry average for reliability trends (see Section 3.3.2 for further detail).

Consultation with Large Consumers

Aurora has a demand management program which targets large capacity connections and provides an opportunity for these consumers to offer feedback on a large number of issues, including service levels. Some of Aurora's large capacity connections in Dunedin and Central are shown below:

- Central Otago: QLDC, CODC, NZ Ski, Queenstown Airport and other large hotels such as Novotel and Corpthorn.
- Dunedin: Otago University, Port of Otago, Turners and Growers, DCC, Cadbury, Fonterra, NZ Wood Mouldings, Southern DHB, Kiwirail, Ravensdown.

Specifically the congestion period demand management service that Aurora provides consists of customer assistance, customer education and monthly reporting to these consumers.

Consultation with Other Stakeholders

Aurora regularly consults with local councils and business groups on major projects; including discussion of the costs and benefits of various projects.

Transpower warrant particular mention here given the interdependency that Aurora has with the national grid. Aurora meet with Transpower on a regular basis throughout the year to discuss capital programmes and ensure alignment where necessary (see Section 6). More recently Aurora has provided feedback on Transpowers proposed customer-facing grid performance measures and dialogue continues with our respective roles and responsibilities in Otago lifelines. In this context, Transpower are interested in understanding how Aurora's

network is developing and the customer demands driving development so they can ascertain how their planning can appropriately respond to it.

3.1.4 Customer complaints

Aurora is required, under the Electricity Industry Act 2010, to be a member of the Electricity and Gas Complaints Commissioner scheme. The scheme has a comprehensive constitution document approved by the Minister of Consumer Affairs, which prescribes the handling of complaints, including timeframes. The requirement for processing complaints regarding Aurora's service (including complaints about Aurora contractors) is detailed in Aurora's Handling of Electricity Complaints policy.

3.2 Evaluation of Performance

Section 2 discussed the main service attributes and objectives that Aurora is committed to achieving and delivering through its asset management practices. For each of these - Safety, Reliability, Quality, Responsiveness, Efficiency, Compliance and Financial performance - Aurora's performance can be evaluated against service level targets that are measured and monitored.

This section provides an evaluation of Aurora's technical/network performance to date and supplements the customer performance results discussed in Section 3.1.

Table 3.2 presents Aurora's service level results for 2012. Performance results over the past 10 years are also presented in this section, with comments on any notable trends. Financial performance for maintenance and capital expenditure for 2012 is presented in Section 3.2.7

3.2.1 Safety

Aurora is committed to providing services that are safe to end-users, the general public as well as our own personnel and contractors.

Safety performance is measured through reporting and recording the number of incidents per year involving the public or personnel and/or non-compliance/non-conformance process. Results to date indicate very few instances when targets have been breached. Over the past 3 years there have been 2 public safety incidents and one personnel. Actions to address safety incidents, such as investigations and corrective actions, are outlined in Section 4 of this AMP. There were 0 incidents reported in 2011/2012.

3.2.2 Reliability

3.2.2.1 SAIDI and SAIFI

Network reliability performance is influenced by many factors; including network design, customer density (connections per km of line), exposure to environment, and extreme weather events. Aurora measures its reliability performance through System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) as well as faults per 100km HV (lines and cables) and concurrently monitors customer complaints. SAIDI provides an overall measure of asset performance for the year. SAIFI assists to monitor frequency of interruptions and helps Aurora to track whether it is meeting expectations for ensuring fewer faults.

The input data necessary for calculating Aurora's reliability statistics is collected and recorded in an Outage Database for both planned and unplanned interruptions to supply; including the duration of the outage, number of consumers affected, and cause. Targets for these are referred to as 'quality thresholds' and are part of the Commerce Commission disclosure requirements.

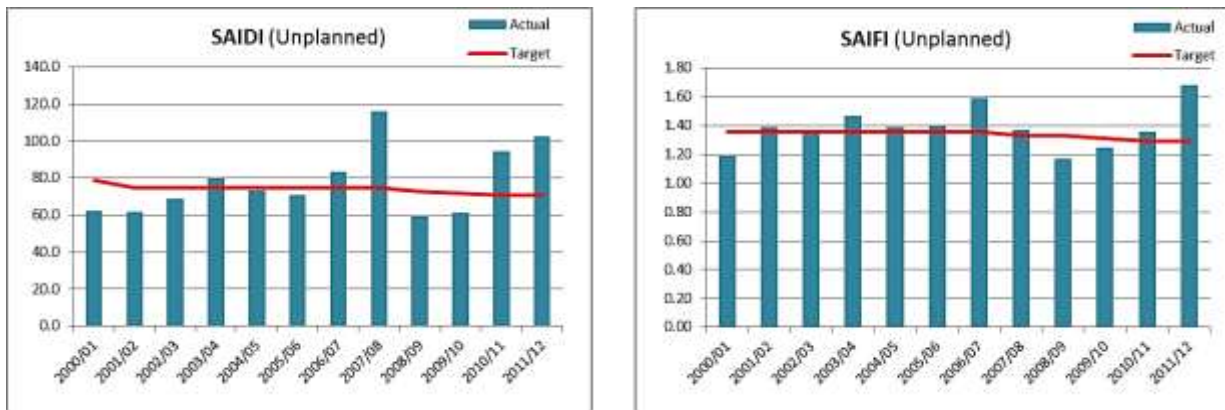
The comments following Table 3.2 are for SAIDI and SAIFI results excluding Transpower initiated events.

Table 3.2 : Service Level Performance Results for 2012

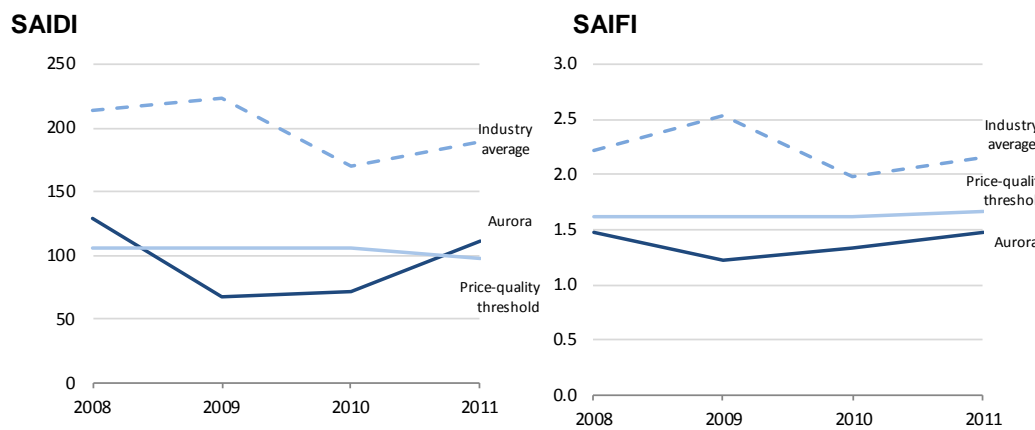
Service Criteria	Performance Indicator	Target (2011/12)	Actual (2011/12)
Safety			
Safety of public	No. of incidents per year	0	0
Safety of personnel	No. of incidents per year	0	0
Safety of network assets	Compliance with standards	Compliance	C
Reliability / Quality			
Network Reliability	SAIDI (Planned)	15.0	13.4
	SAIDI (Unplanned)	71.0	102.5
	TOTAL	86.0	115.9
	SAIFI (Unplanned)	1.27	1.67
Faults per 100 km HV	No. per year	11.4	11.2
Faults per 100 km HV UG	No. per year	2.50	2.35
Faults per 100 km HV OH	No. per year	13.5	15.13
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	4.0
Network Restoration	CAIDI (unplanned)	55	77.9
Responsiveness			
Restore supply following general network failure	Within 4 hours of notification (Dunedin)	<4	73% restoration within 3 hours
	Within 4 hours of notification in urban areas (Central)	<4	
	Within 6 hours of notification in rural areas (Central)	<6	
			Valid claims
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	-	0
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	-	0
Notification of planned service interruption	Missing notification of planned interruption	-	1
Efficiency			
Load factor (%)	Energy into network/peak kW hours per year	≥52%	53%
Loss ratio (%)	Energy into network less energy delivered / energy into network	≤6%	6.4%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	≥30%	32.9%
Environmental / Compliance			
SF6	No. of incidents per year	0	0
PCBs	No. of incidents per year	0	0
Oil spills	No. of incidents per year	0	0

Quality Threshold Targets

Trends for SAIDI and SAIFI over the past 10 years are shown on the following page. Overall the results indicate an upward trend, with the outage average duration and frequency increasing over time. Results for 2011/12 show that Aurora has breached its quality thresholds (and similarly in 2010/11). Excluding planned shutdowns, over the past 10 years, the recorded (known) cause of these interruptions was predominantly tree contact and weather (wind), equipment deterioration and third party. This poses a challenge for Aurora as consumer surveys have indicated they are not willing to pay more for an improvement in quality, preferring a decrease in charges with no more interruptions. Overall, Aurora's average duration and frequency of interruptions was below the industry average over the 2008-2011 period.



A comparison of Aurora's SAIDI and SAIFI trends 2008-2011 against the industry is shown below.³



A comparison of SAIDI for against other EDB's in 2010/11 is shown below.⁴

Contract Performance Targets

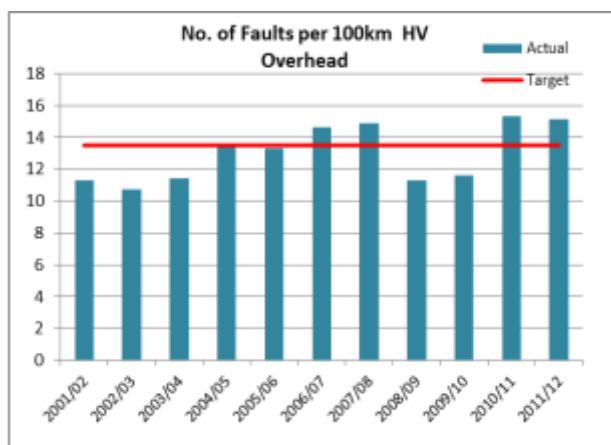
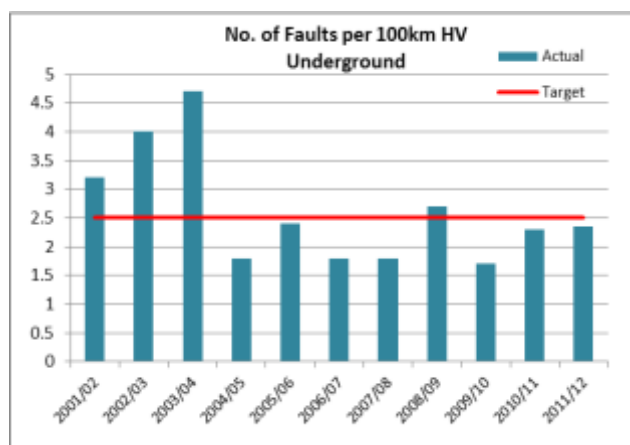
While the above regulatory quality thresholds are the key performance targets that Aurora is monitored against, Aurora has also historically set 'stretch' targets in Delta's asset management contract requirements to drive continuous improvement and best practice asset management.

Faults

Results for 2011/12 show that Aurora was below target for underground faults and slightly above target for overhead faults. Over the past 10 years, the results indicate a declining trend in underground faults compared to overhead, reflecting that the most of the reliability issues are associated with overhead lines may be influencing this, however further investigation is required.

³ Commerce Commission NZ (2013) Electricity distributors' performance from 2008-2011. Public Version.

⁴ The PwC compendium for 2011/12 had not been published at the time of writing this AMP.



3.2.3 Quality

Aurora is committed to providing services that are not only reliable but also of quality, particularly with respect to providing a steady state level of voltage. Variations to voltage can affect the quality of power delivered to the end user and may result in momentary fluctuations or affect consumer appliances, the cause of which is primarily due to rising loads or failing conductor joints, and mainly occurs during winter when loads are highest.

Aurora measures its quality performance through monitoring and responding to reports or complaints received during the year as well as feedback via annual consumer surveys. Any complaints received during the year are logged and investigated to validate if they are actually voltage-related. Depending on the complexity of the situation, it may be some time for before the cause is confirmed, solution designed and/or additional investment is made.

Aurora has set targets relating to the maximum number of valid voltage complaints over the total network, being (less than) 10 per 10 000 consumers per annum (so approximately 80 voltage complaints per year). Results over the past 4-5 years indicate that the number of valid voltage complaints received throughout any one year has ranged from 9 – 32.

Central Otago respondents have consistently rated voltage fluctuations as being an important issue relating to quality of supply, compared to Dunedin respondents. Results for 2011/12 show that Aurora received 32 valid voltage complaints (29 in Dunedin and 3 in Central).

While the number of proven voltage complaints has continuously been below target, there appears to be an upward trend emerging (based on the last three years results). Further investigation into reasons for this is required.

3.2.4 Responsiveness & Restoration

Aurora is committed to resolving consumer issues in a responsible and timely manner. Because Aurora has contracted out management of its assets to Delta, Aurora monitors Delta's performance to ensure appropriate customer service levels are maintained for such matters as answering telephones and correspondence. Aurora's performance measure results for responsiveness were shown previously in Table 3.2.

For general customer enquiries and issues relating to power or voltage Aurora's commitment is that, within 7 days, it will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem. If the investigation cannot be completed within 7 working days, then Aurora will provide, within that period, an estimate of the time it will take to complete the investigation. Aurora will remedy any problems under its control in a timely manner, in accordance with good industry practice.

Aurora provides a 24 hour service for direct fault calls and emergency contact⁵; and maintains a complaints register to log complaints and track resolution.

⁵ The 24 hour service has a limited capability and consumers are encouraged to call their retailer for up-to-date information on fault restoration.

Further to this, Aurora has set a 'service guarantee' if the timeframe is exceeded (Table 3.3).

Table 3.3 - Service Guarantee

Service Criteria	Performance Indicator	Service Guarantee for exceeding the time-frame
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem	\$50
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected due to the nature of the problem	\$50
Notification of planned service interruption	Missing notification of planned interruption	\$20 per ICP per missed communication

If, as a result of a general network failure, supply has not been restored within four hours (urban areas) or six hours (rural areas) of notification of the failure, then Aurora will pay the Electricity Retailer:

- \$50 (including GST) for 8 kVA and 15 kVA standard domestic connections;
- one month's use-of-system charges for other connections.

The actual spend on service failure payments over the past 10 years is shown in Table 3.4. While variable, there is a general increasing trend in the number of events and therefore total paid.

Table 3.4 – Historic Service Failure Payments

Year to 30 June	Events	Consumers Affected	Total Paid	% of Line Revenue
2003	11	1148	\$63,336	0.119%
2004	16	415	\$25,410	0.048%
2005	24	896	\$51,553	0.091%
2006	14	324	\$21,435	0.036%
2007	15	246	\$13,210	0.021%
2008	16	1171	\$61,717	0.092%
2009	14	671	\$36,094	0.044%
2010	24	794	\$48,653	0.068%
2011	33	1897	\$143,366	0.195%
2012	26	1183	\$79,275	0.103%

The survey results presented in Section 3.1 indicate that consumers appear to be accepting a longer timeframe for restoration in both Dunedin and Central and this trend has been increasing since 2006. However, results for 2012 indicate a shift in this trend. Central consumers appear less tolerant of longer restoration times compared to Dunedin. However, consumer feedback also tells us that there still appears to be some level of dissatisfaction with the response being provided.⁶

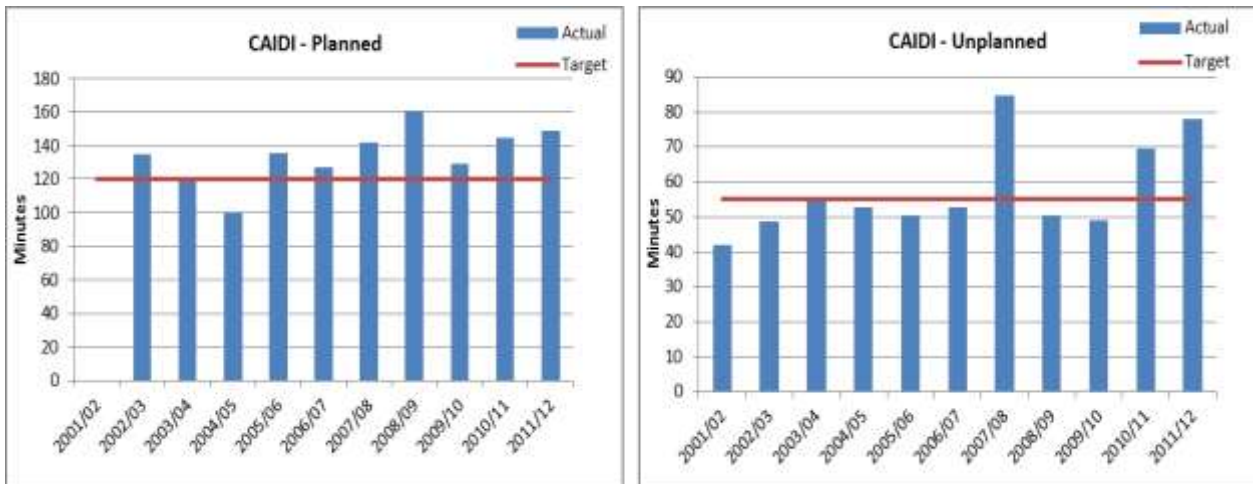
For 2013, Aurora will continue with its commitment to respond to enquiries regarding power quality or service interruption investigations within 7 working days.

3.2.4.1 Restoration

CAIDI (Customer average interruption duration index) represents the average duration of an interruption to supply for consumers that have experienced an interruption. CAIDI is used by Aurora to measure restoration performance which tracks the average duration of an interruption to supply for consumers that have experienced an interruption. Results over the past 10 years indicate that unplanned CAIDI is generally below target, but

⁶ Note, that it is currently unclear whether the survey results for length of interruptions definitively correlate with Aurora's service performance for 'responsiveness', as the means to adequately monitor and record such information is still being determined.

planned CAIDI is frequently above (see graphs below). Overall, there is an increasing trend in CAIDI, reflecting the trend seen in SAIDI and SAIFI. CAIDI results for 2011/12 exceeded target.



Of the 484 unplanned interruptions on the network in 2011/12, approximately 73% were restored within 3 hours. These results are still well under Aurora's current service level response times for restoring supply in urban Dunedin and Central, discussed in Section 3.2.4.

For consumer groups, restoration target levels are shown in Table 3.5, and provide a more practical explanation of service level delivery. Aurora uses restoration information to provide a comparison between urban and rural network performance. Results show that there is an increasing trend of interruptions occurring in urban areas versus rural over the whole network (see graphs below).

In the year ended 2011/12, (16.4%) urban consumers experienced more than four interruptions and 6.6 % rural consumers experienced more than 10 interruptions. This was similar to the previous year. The 10 worst performing feeders are outlined in the following section and this information shows that the majority of these feeders are located within the Central network.

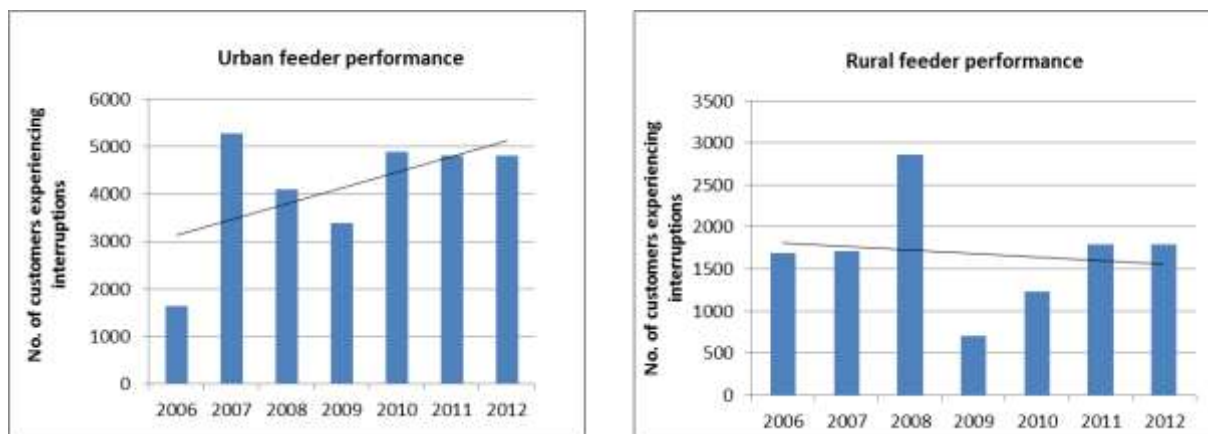


Table 3.5 Number and Duration of Outages by Consumer Location

General Location	Performance Measure	Target
Dunedin Network		
Otago University, Hillside Workshops	Outages no longer than 4 hours every 5 years	≤ 1
Dunedin urban CBD	Outages no longer than 4 hours every 5 years	≤ 1
Dunedin urban suburbs	Outages no longer than 4 hours per year	≤ 2
Taieri Plains, Otago Peninsula	Outages no longer than 4 hours per year	≤ 4
Central Otago Network		
Major urban areas in Central *	Outages no longer than 4 hours per year	≤ 2
Smaller towns in Central **	Outages no longer than 6 hours each year	≤ 4
Rural areas in Central	Outages no longer than 6 hours each year	≤ 10
Remote rural areas in Central	No. of outages each year	< 20

*Alexandra, Queenstown, Cromwell, Wanaka

**Arrowtown, Roxburgh, Clyde, Ettrick, Omakau, Lake Hawea, etc

Worst Performing HV Feeders

Feeders assessed as being the 'worst performing' over the past 4 years are shown in Table 3.6. Those in the first column have more frequently been reported as worst performing (based on SAIDI minutes). Of these, nearly 80% are located within the Central network (predominantly rural areas). The feeders highlighted in green are those that were associated with significant outages in 2010/11 and 2011/12.

Table 3.6 - Worst Performing Feeders

Location Description	Feeder no.	Location Description	Feeder no.	Location Description	Feeder no.
Closeburn/Glenorchy	QT5202	Lake Hayes	AT7632	Mosgiel East	ET8
Omakau West/Poolburn	OM679	Gibbston Valley	AT765	Fernhill	FH5308
Lower Peninsula	PC3	Arrow Junction	AT7652	Ladies Mile, Lake Hayes Estate	FK704
Luggate	WK2752	Springvale	AX168	Remarkables Park	FK7783
St Bathans	OM634	West Cromwell	CM832	Waldronville	GI11
Bannockburn	CM821	Pisa Moorings	CM891	Omakau West	OM669
Hawea Flat	MA244	Dalefield	DA7828	Arrow Junction	OT7652
Hawea	MA260	Saddle Hill, Chain Hill	ET2	Sawyers Bay	PC4
Aramoana	PC5	Brighton, Taieri Mouth	ET3	Glenorchy	QT910

In response to these results a targeted capital investment programme for the worst performing feeders has commenced and remote switching for rural areas has also taken place in the recent past. Last year, the feeders in Table 3.7 were identified for attention; and the results from work carried out on the network to address these are presented. Refer to Sections 5 and 6 of this plan for further detail on related projects and expenditure.

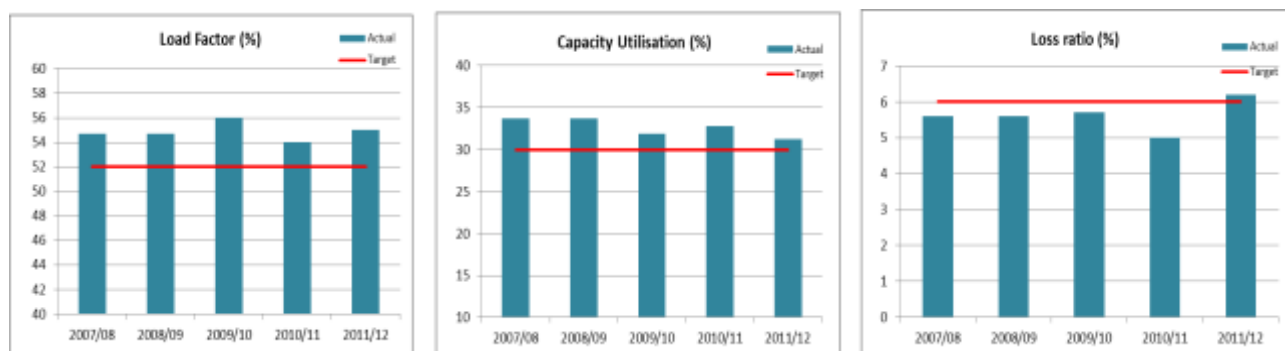
Table 3.7 - Targeted Improvement in the 10 Worst Performing Feeders

Area	Improve Reliability	Measure	Target Level	Results	Achieved Y/N
Closeburn	QT5202	Reduce SAIDI and No. of Interruptions	Reduce by 25%	73% SAIDI reduction 50% Interruption reduction	Y Y
Fernhill	FH5308	Reduce SAIDI minutes	Reduce by 15%	83% SAIDI reduction	Y
Dalefield	DA7828	Reduce SAIDI minutes	Reduce by 15%	54% SAIDI reduction	Y

Remarkables park	FK7783	Reduce SAIDI minutes	Reduce by 10%	47% SAIDI reduction	Y
Sawyers Bay	PC4	Reduce SAIDI minutes	Reduce by 10%	58% SAIDI reduction	Y
Hawea	MA260	Reduce SAIDI and No. of Interruptions	Reduce by 10%	56% SAIDI reduction 92% Interruption increase	Y N
Luggate	WK2752	Reduce SAIDI and No. of Interruptions	Reduce by 10%	51% SAIDI reduction 77% Interruption reduction	Y Y
Pisa Moorings	CM891	Reduce SAIDI and No. of Interruptions	Reduce by 10%	86% SAIDI reduction 69% Interruption reduction	Y Y
Gibbston Valley	AT765	Reduce SAIDI and No. of Interruptions	Reduce by 10%	80% SAIDI reduction 36% Interruption reduction	Y Y
Omakau west	OM679	Reduce SAIDI and No. of Interruptions	Reduce by 10%	36% SAIDI reduction 54% Interruption reduction	Y Y

3.2.5 Efficiency

Aurora's energy efficiency is measured through load factor, loss ratio and capacity utilisation. Table 3.2 presented the results for Aurora's efficiency targets. Overall, Aurora achieved results for network efficiency that were on or near target (see graphs below)



Load Factor

Better utilisation of capacity in the network can be gained through optimising the load factor, which is a measure of the average load that passes through the network divided by the maximum load experienced in a given year. A high load factor means power usage is relatively constant. Low load factor indicates that occasionally a high demand is set; however in order to service that higher demand, capacity is under-utilised for extended periods, increasing system costs. Aurora achieved a load factor of 53% in 2011/12 against a target of 52%. Aurora's load factor has been slightly above target each year over the past 5 years and there is merit in revising the target to 54%.

Capacity Utilisation Ratio

This ratio measures the utilisation of transformers installed on Aurora's network and is calculated as the maximum demand experienced divided by the distribution transformer capacity on the network. For 2011/12, capacity utilisation was 32.9% against a target of 30%. Over the past 5 years this has been slightly above target each year, but trending downwards. However it is expected that better utilisation may start to occur within the Central network due to emerging irrigation demands which may see increased use in summer.

Energy Loss Ratio

Energy losses mainly occur due to heating of lines, transformers and cables. Theft can also be an issue. In general, losses cannot be avoided and therefore all electricity networks experience losses to some degree. For 2011/12, Aurora's energy loss ratio was 6.4% against a target of 6%. This the first year it has been above target over the past 5 years and appears to be the result of retailer energy reconciliation reporting, particularly in the Clyde and Cromwell GXP's. Reconciliation issues are expected to be resolved over time and, accordingly, Aurora has retained a target loss ratio of 6%.

Pricing policies

Aurora encourages improvement in the above ratios through its congestion period demand pricing policies, which strongly incentivise the use of electricity during off-peak periods. The congestion period is approximately 150 to 250 hours per year, during May to August.

Despite this pricing signal, the limited use of gas for heating purposes coupled with the location of several ski-fields in the Central Otago area, results in high loads occurring during winter. Aurora continues to promote the use of electricity during off peak periods through strongly signalling the high cost of delivery during peak periods compared to off-peak periods. Refer to the Use-of System pricing methodology on Aurora's website.

3.2.6 Compliance

There are a variety of regulatory compliance requirements that Aurora must meet when planning for and delivering services. These cover environmental, health & safety, hazards to name a few. Section 2 covered the main pieces of legislation that Aurora aims to achieve material compliance with when managing the electricity distribution network.

Along with targets for compliance with safety and safety standards (Section 3.2.1), Aurora aims to minimise or eliminate the risk of discharges to the environment from oil spills, PCB's and SF6. More recently, the risk of this has been further reduced through the use of oil filled circuit breakers ceasing in favour of vacuum circuit breakers. However, the oil-based distribution switchgear used by Aurora is being discontinued and SF6 is likely to become the insulation medium.

In some parts of the network ester-based oil is used. This is considered as posing less of a risk to the environment in the event of a spillage. A review of on the policy for the type of oil used within different parts of the network is planned.

No significant environmental incidents occurred in Aurora's network areas for the 2011/12 year.

3.2.7 Financial Performance

Over the past 8 years, actual capital expenditure has been variable with respect to budget. Maintenance expenditure has been less variable and mainly comes in above budget. Table 3.8 presents results for 2011/12. The text below identifies the causes of variance and the major items under construction as at 31 March.

Table 3.8 Financial Performance Results for 2012

Category	Budget 11/12 \$000	Actual 11/12 \$000	Variance	
			\$	%
Maintenance Expenditure				
Routine and Preventative Maintenance	3,540	3,236	304	9%
Refurbishment and Renewal Maintenance	1,310	1,521	-211	-16%
Fault and Emergency Maintenance	4,270	4,536	-266	-6%
Total	9,120	9,293	-173	-2%
Capital Expenditure				
Customer Connection	5,600	3,517	2,083	37%
System Growth	7,090	5,396	1,694	24%
Asset Replacement and Renewal	2,020	1,834	186	9%
Reliability, Safety and Environment	8,490	4,979	3,511	41%
Asset Relocations	400	788	-388	-97%
Total	23,600	16,514	7,086	30%

Progress of maintenance initiatives and programmes

The causes of variances in the Maintenance budget can be attributed to fault response requirements and additional requirements for refurbishment and renewal spend.

Progress of development projects

The main causes of variances in the CAPEX budget are outlined below:

- Customer Connections - The effects of the global financial crisis continues to suppress consumer initiated development work.
- System Growth - Wanaka HV interties delayed.
- Asset Replacement and Renewal - Roxburgh substation upgrade deferred until 2012/13. Now total substation renewal.

- R, S & E - First stage of line renewal projects required time to complete designs, approvals and mobilisation delaying start until four months into year.
- Capital Expenditure: Asset Relocations - Greater than expected level of requests to move works by LTAs and third parties.

The table below shows the major Aurora works items under construction as at 31 March 2013.

Item	Value (\$000)	Status
Andersons Bay 33kV Cable replacement	\$3,200	Works have commenced with trenching and ducting completed.
Roxburgh Substation	\$2,100	Commissioning to commence in March
Queenstown 11kV Switchgear	\$1,100	Construction to commence in March
Line Renewals	\$3,000	In progress

3.2.7.1 Economic Efficiency

Economic efficiency reflects the level of asset investment required to provide network services to consumers and the operational costs associated with managing these assets.

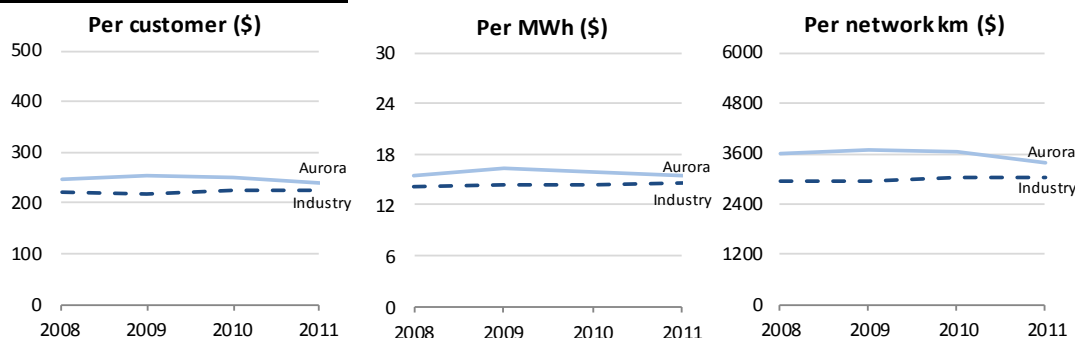
Aurora's consumer surveys indicate that consumers perceive price as being more important than quality, and they are generally less willing to pay more for an improvement in quality (reliability), but at the same time also do not want to pay less if it means there may be more interruptions. As such, providing a cost effective, reliable and secure network for electricity delivery is a primary focus for Aurora.

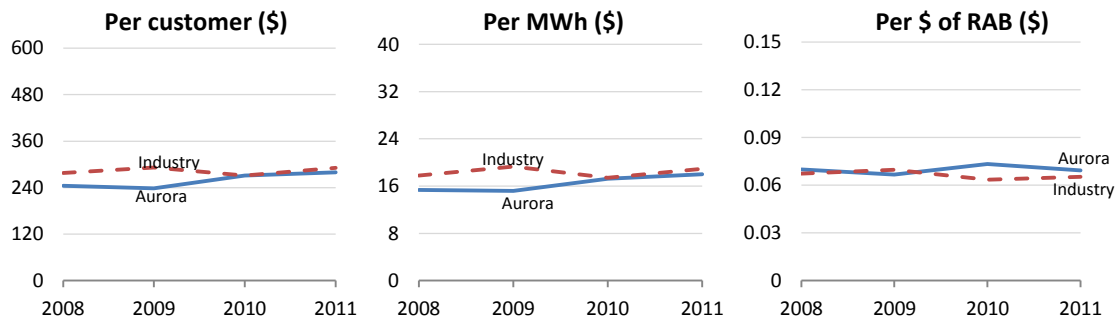
The Commerce Commission places emphasis on measuring and reporting both capital and operational expenditure. As such, Aurora tracks progress against the industry average through the benchmarking information collated by PricewaterhouseCoopers on an annual basis (PwC 2011, Electricity Lines Business (2011) Information Disclosure Compendium) as well as referring to the Commerce Commission's performance report for EDB's.

A sample of Aurora's trends in operating and capital expenditure over the period 2008-2011 are shown in the graphs that follow. For Opex, Aurora has been slightly above the industry average but is also shown to be trending towards this. For Capex, Aurora has been slightly below the industry average but is also shown to be trending towards this.

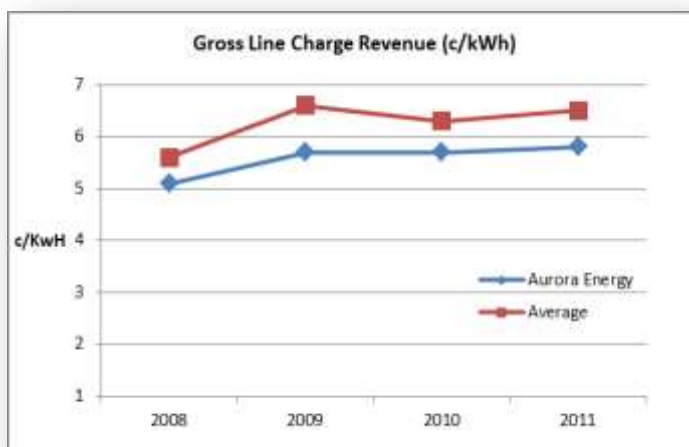
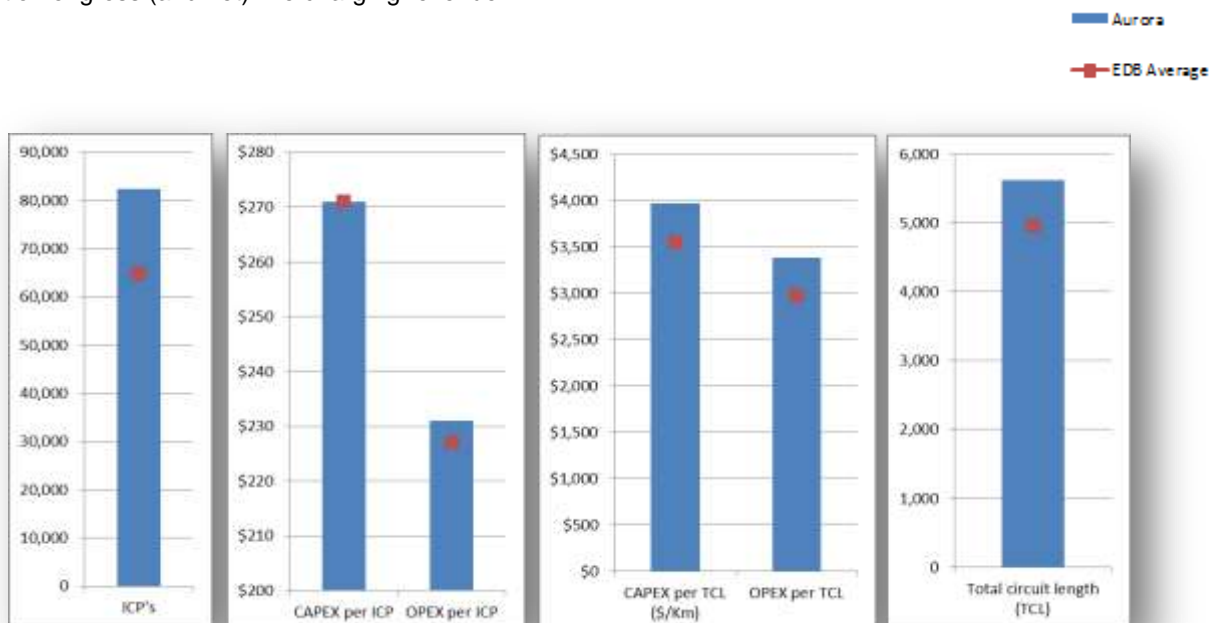
Most of Aurora Energy's revenue is collected from residential and smaller commercial customers. Revenue from line charges increased by around 3% from 2008 to 2011, over and above inflation. Distribution line charge revenue from residential and smaller commercial customers stayed flat, but increased for medium-sized customers by around 20%.

Operating Expenditure trends



Capital expenditure trends

The graphs below provide an indication of where Aurora sits against the industry average against some of the other measures for 2011 (PwC 2011, Electricity Lines Business (2011) Information Disclosure Compendium). These also indicate that Aurora is generally aligned to the industry average albeit slightly above, with the exception of gross (and net) line charging revenue.



3.3 Service Level Targets & Justification

Service level targets for 2013 are shown in Table 3.9, including the proposed average annual targets for the next 5 years. A discussion on the reasons for the service level targets has been provided in Section 3.2, which forms the basis on which each service level target has been determined for 2013/14. In setting these, Aurora has given consideration to the customer feedback/surveys, historic trends in network performance, knowledge of current network health/risk areas, economic viability and funding availability, with safety-first being paramount.

While the results outlined in the previous section as well as the benchmarking information generally support the proposed service level targets, they have also identified areas that need attention; and include: reliability, responsiveness/restoration. Proposed performance improvements for the network are therefore covered in Sections 5 and 6; and asset management practice and process improvements are discussed in Section 7.

In summary, the main drivers that influence Aurora's service levels are related to business and stakeholder/consumer needs and legislative requirements; as these influence decisions about the range, quality and quantity of services provided.

Table 3.9 – Future service levels and targets

Service Criteria	Performance Indicator	Targets (2012/13)	Avg Annual (2013-2017)
Safety			
Safety of public	No. of incidents per year	0	0
Safety of personnel	No. of incidents per year	0	0
Safety of network assets	Compliance with standards	Compliance	Compliance
Reliability / Quality			
Network Reliability	SAIDI (Planned)	14.0	13.6
	SAIDI (Unplanned)	70.0	68.4
	TOTAL	84.0	82.0
	SAIFI (Unplanned)	1.27	1.24
Faults per 100 km HV	No. per year	10.5	10.4
Faults per 100 km HV UG	No. per year	2.5	2.5
Faults per 100 km HV OH	No. per year	13.5	13.5
Customer Complaints	No of proven voltage complaints per 10,000 consumers per year	<10	<10
Network Restoration	CAIDI (unplanned)	55	55
Responsiveness			
Restore supply following general network failure	Within 4 hours of notification (Dunedin)	<4hrs	<4hrs
	Within 4 hours of notification in urban areas (Central)	<4hrs	<4hrs
	Within 6 hours of notification in rural areas (Central)	<6hrs	<6hrs
		Valid claims	Valid claims
Response to customer enquiries	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	0	0
Response to power quality or voltage	Within 7 days Aurora will investigate and respond in detail or advise when a final response can be expected	0	0
Notification of planned service interruption	Missing notification of planned interruption	0	0
Efficiency			
Load factor (%)	Energy into network/peak kW hours per year	54%	54%
Loss ratio (%)	Energy into network less energy delivered / energy into network	6%	6%
Capacity utilisation (%)	Peak network kW / installed distribution transformer capacity kVA	30%	30%
Environmental / Compliance			
SF6	No. of incidents per year	0	0
PCBs	No. of incidents per year	0	0
Oil spills	No. of incidents per year	0	0

3.4 Capability to Deliver

The AMP planning process intends to ensure that on-going and annual reviews of policy, process and performance informs asset management requirements and associated resource needs. While the targets are generally achievable given the current network configuration, condition and planned expenditure levels, there are some areas that do require further analysis to clearly understand how practical the current asset management objectives are, particularly as trends in actual expenditure against budget to date have been variable for capital, with maintenance being mainly above budget.

Recent changes to organisational structures, roles and responsibilities outlined in Section 2 have allowed for improved means of authorisation and business capabilities to support the implementation of asset management plans. However, skill shortages and current resource (personnel) limitations are acknowledged as a key factor influencing the timeframe required to plan and deliver the quantum of work programmed over the 10 year period. These risks along with others are discussed further in Section 4. While prioritisation processes assist to focus on areas considered to be high risk, further work is required to more accurately quantify and prepare for future needs (including training and development). Aurora will continue to work on gaining a better understanding of these needs over the coming year.

The following section discusses risks associated with the network and network performance as well as business risks that are being managed by Aurora.

4 Risk Management

4.1 Introduction

Aurora has contracted Delta to undertake asset management services for Aurora under a performance related contract. Delta recognises that risk management is fundamental to asset management and as such has undertaken risk management and business continuity planning for all the services and assets that Aurora is responsible for. Note that where references are made to Delta in this section, that reference by implication also includes Aurora as a result of the contracting arrangement in place.

4.2 Context

A review of risk management philosophy, framework and approach has been undertaken as part of a Risk and Business Continuity Project. The outputs from this are being used to introduce more robust risk management objectives, processes and systems so that Aurora can identify and plan for acceptable levels of risk. The approach to this is based on the AS/NZS ISO 31000:2009 Risk Management Standard and the risk management framework is demonstrated in the following diagram (Figure 4.1).

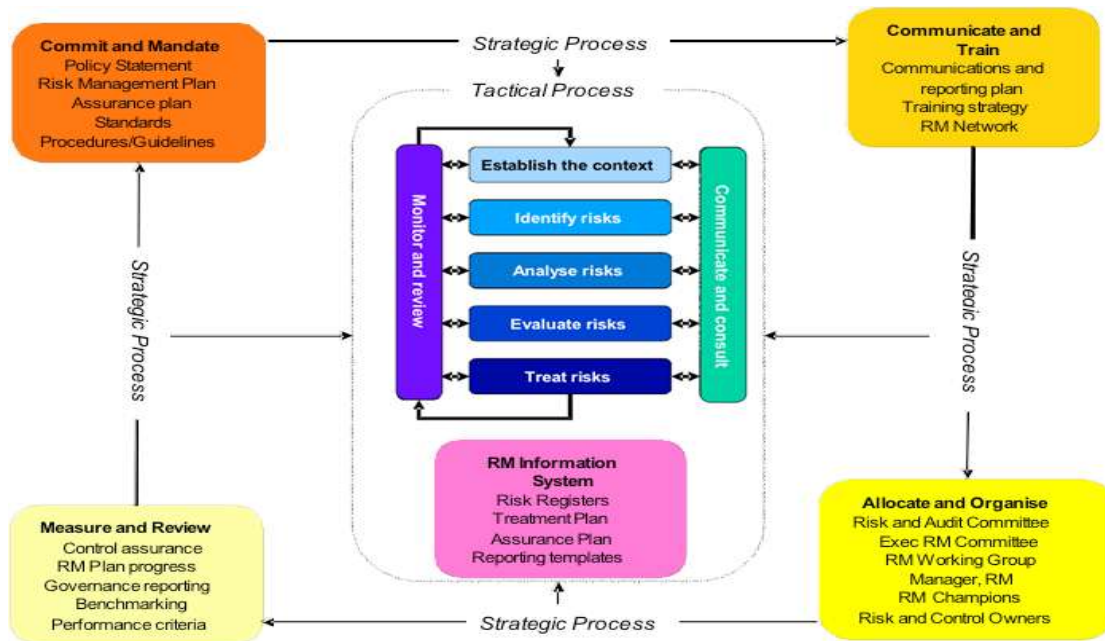


Figure 4.1 - Risk Management Process (AS/NZS ISO 31000:2009)

4.3 Responsibilities for Risk Management

Figure 4.2 sets out the responsibilities for risk management and is followed by commentary on risk responsibilities.

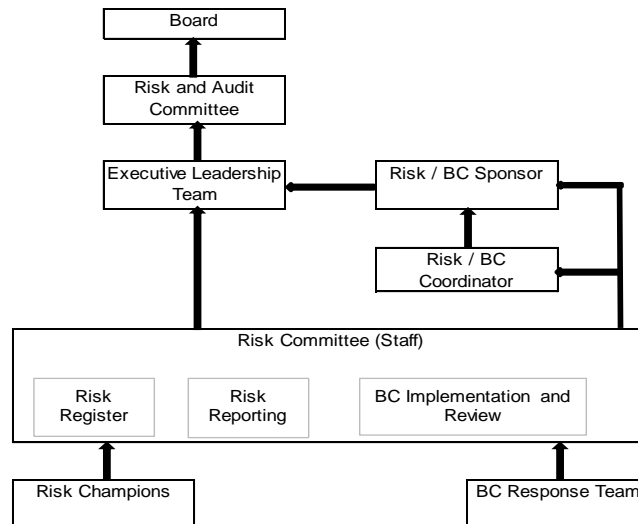


Figure 4.2 - Risk Management Responsibilities

Board

The Board have overall responsibility for risk management. Significant risks are reported to the Board. The Audit and Risk Committee is delegated the governance responsibility for risk management.

Audit and Risk Committee

The Audit and Risk Committee provides oversight of risk and assurance framework and performance.

The Audit and Risk Committee meets monthly to review the risk context, key risks and key controls.

Executive Leadership Team

All Executive Leadership Team members and their Managers are responsible for ensuring the implementation of the risk management process through implementation of risk plans / tools and processes; risk identification analysis and management within their function; risk analysis and evaluation at the leadership team level; staff capability and training for risk management.

Managers

Managers are responsible for managing risks within their portfolios through the application of risk management process and systems including training, risk identification, risk analysis (risk register), risk treatment and risk monitoring / reporting.

Project/Asset Managers and Staff

Project Managers and staff are responsible for the day-to-day management of project risks that affect the achievement of project / programme objectives through risk identification and analysis, risk management intervention (treatment plans) and monitoring, and risk reporting.

Suppliers/Contractors

Where an activity is outsourced, the supplier/contractor is to ensure that risk management plans, processes, systems and tools (e.g. risk register) are implemented, risk reporting to the manager responsible project being delivered by the supplier / contractor, and mitigation of risks in accordance with direction from the Principle.

Business Continuity Overview

A business continuity programme has been developed that supports risk management. Senior management have committed to leadership and sponsorship of the business continuity programme. This will help ensure that the organisational culture recognises that business continuity is an important part of normal business practice, and

therefore an operational responsibility for all staff. To enable this to occur a Business Continuity Policy and Framework document has been adopted.

A Business Continuity Plan and a Business Continuity deployment plan (ready response guide) have been written to address major business interruptions.

4.4 Risk Process & Methodology

Risks are analysed in terms of treatment using the following methods:

- **Actively accept** – accept the risk and consider options for the treatment of the risk;
- **Passively accept** – accept the risk as it is, i.e. no further treatment is appropriate or possible at this time;
- **Transfer/share** – pass the risk in whole or part to others e.g. through contractual agreements or insurance. Appropriate where others are best able to manage the risk;
- **Avoid** – change parts of the activity so that there is no longer any exposure; and/or
- **Active treatment strategies:**
 - **Minimise** – reducing the likelihood of experiencing the threat; and / or;
 - **Mitigate** – reduce the consequence of experiencing the threat by means such as establishing 'post occurrence' contingency and disaster plans to reduce the consequence of experiencing the risk.

Risks need to be controlled and managed within acceptable limits to achieve the most satisfactory outcome. Where risk cannot be eliminated, training, competency, safe work practices and asset design / maintenance are used to control risks.

Risk also includes opportunities. Opportunities for network improvement, capital / operating expenditure spend (efficiency and effectiveness) and workplace practice efficiency need to be identified and where appropriate, accepted and implemented.

Risk is measured by likelihood / consequence as set out in the following table. The context in which each risk is addressed is the significance of the risk on the activity in question.

Table 4.1 Likelihood and Consequence Matrix

Likelihood of Frequency	Almost certain (5)	Class 2 Moderate	Class 2 Moderate	Class 3 High	Class 4 Critical	Class 4 Critical
	Likely (4)	Class 2	Class 2	Class 3	Class 4 Critical	Class 4 Critical
	Possible (3)	Class 1 Low	Class 2 Moderate	Class 2 Moderate	Class 3 High	Class 3 High
	Unlikely (2)	Class 1 Low	Class 1 Low	Class 2 Moderate	Class 3 High	Class 3 High
	Rare (1)	Class 1 Low	Class 1 Low	Class 1 Low	Class 2 moderate	Class 3 High
		Insignificant	Minor (2)	Moderate	Major (4)	Extreme (5)

The level of risk acceptability and the management of the classes of risk set out above are explained in the following table:

Table 4.2 - Acceptability / Management Required

Risk Level	Significance	Level of Risk Acceptability	Extent of Management Required (e.g. Prevention, Mitigation, Reporting, Auditing)
Class 1	Low	Tolerable if improvement is uneconomic.	Low-cost prevention or mitigation where justified. Should be periodically reviewed.
Class 2	Moderate	Most likely unacceptable; but may be tolerable if the cost of risk elimination or reduction is greater than the improvement gained.	Preventive measures and mitigation measures required, where practicable. Requires routine review.
Class 3	High	Unacceptable without further control or treatment; may be tolerable if the cost of elimination or reduction is significantly greater than the improvement gained.	Preventive measures are required where practicable. Mitigation measures required in all cases. Requires regular review. Reported immediately to the Divisional Manager.
Class 4	Critical	Intolerable. Risk reduction must be implemented.	Prevention and mitigation measures reported immediately to the Chief Executive.

4.4.1 Risk Management Policy

Aurora endorses and implements the following risk management policy statements. :

- That a risk management framework and process in compliance with good practice (using the AS/NZ ISO 31000:2009 Risk Management Standard) developed and maintained;
- All risks will be recorded, captured and maintained in the Risk Register;
- Significant risks must be identified, analysed, assessed and reported on a timely basis to the appropriate level of management;
- Project managers will ensure project risks are identified and captured in risk reports to management and the Audit and Risk Committee / Board;
- Risk controls or mitigations are current, tested and remain effective;
- Learning from incidents, investigations or other sources will be part of continuous improvement;
- Staff are adequately trained, skilled and resourced for managing risks;
- Risk management is part of the culture of operations of Delta and Delta's contractors;
- Risk performance measures will be used in management reporting processes;
- The risk management process outlined in the framework document is to be used at all times, except when management determines that because it has low levels of uncertainty or is less complex that it realises little or no value.

Risk Assessment

A risk assessment worksheet is used to capture detailed data on each risk. The worksheet identifies the following information:

- Risk assessment number
- Activity
- Risk description and hazards
- Risk category
- Consequence and likelihood assessment
- Worst foreseeable outcome
- Risk analysis
- Management / Effectiveness of controls
- Treatment options
- Risk action plan

The risk register contains the following data:

- Risk assessment number

- Risk type
- Risk name
- Description
- Status – active / dormant / closed
- Threat or opportunity
- Existing controls
- Consequence and likelihood assessment
- Score (out of 25)
- Treatment plan summary

Risk categories

The following list outlines the risk categories that are used to categorise the types of risks that Aurora has (or will identify) as part of its risk management programme:

- **Health and Safety** – a risk that threatens the physical safety of staff, contractors or the public.
- **Operational Capability** – a risk that reduces or prevents the company being able to successfully deliver its services or manage its assets.
- **Skills and Knowledge** – a risk that is created because the level of skills and knowledge about systems processes and asset management is not available.
- **Cultural/Community** – a risk where there is a direct impact to the community as a result of a system, process or asset failure.
- **Legal Compliance** – a risk where the company is found to have breached an existing regulation / compliance requirement, or where regulatory requirements impact on the ability and capacity of the company to manage its assets and services to meet the community requirements in a cost effective manner.
- **Financial** – a risk where the company will suffer a direct financial loss or fail to take advantage of an opportunity to generate a financial benefit.
- **Reputation** – a risk that could or does result in serious damage to the reputation of Aurora
- **Environment** – a risk that could or does result in a negative impact on the environment because of an activity being undertaken by Aurora.
- **Time (projects)** – a risk where failing to achieve time deadlines will result in a negative impact on assets and services.

The following section covers details on these categories under the headings of ‘network’ and ‘business’ risks.

4.5 Network Risks

The following section provides information regarding the main network-related risks linked to the asset management attributes of safety, reliability, quality and security.

4.5.1 Safety

The Health and Safety in Employment (HSE) Act is a key item of safety legislation impacting on Aurora’s contractors. While not overriding safety requirements found in the Electricity Act and Regulations, the HSE Act has far reaching impact; requiring all hazards associated with assets to be identified, assessed, and controlled, if found to be significant.

A healthy and safe environment is achieved by duties set by all parties associated with design, construction, maintenance and operation of Aurora assets.

Hazards are controlled through training, guidelines and standards. Potential hazards, in particular electrical hazards, must also be considered when new network installations are being designed and constructed.

Hazards have been included in the risk register under specific risk headings.

All operation and maintenance work performed on Aurora network assets must be performed in accordance with “Safety Manual, Electricity Industry”, which is a set of safety rules for the New Zealand Electricity Generation, Transmission and Distribution Industry.

This publication is an industry-accepted standard, and provides a means of complying with the safety requirements of the HSE Act, the Electricity Act, Electricity Regulations, and subsequent amendments.

The “Southern Power Companies’ HV Safety Procedures” complement the Safety Manual by specifically detailing and standardising methods of compliance with those rules.

The Building Act 1991 impacts on various Aurora facilities, requiring that buildings are safe, sanitary, and offer adequate means of escape from fire.

Staff

Aurora requires Delta’s line managers to take responsibility for themselves and their staff to manage hazards which may be present in their work areas. A risk based hazard assessment has been implemented and Delta uses a systematic approach to identify, assess and manage potential hazards in the work place. The Safety Action Groups (SAG) provides the mechanism for delivering and monitoring health and safety practices including reporting. Support from health and safety practitioners are also important.

Contractors

Contractors are responsible for ensuring that they meet all necessary safety requirements and obligations for working on Aurora assets. Under the HSE Act contractors are responsible for safety and competency of their employees working on Aurora assets. Contractors must have their own documented health and safety management systems and they are further reminded of their health and safety obligations when they sign a new contract. Regular site audits are carried out to ensure compliance. Since almost all work associated with Aurora’s network is carried out by contractors (and the main asset management contract being with Delta), a risk register has been developed of specific known hazards along with recommended actions to control hazards. Most hazards can be managed if access to hazardous areas is restricted to competent personnel, and industry recognised safe working practises are used.

Public

In 2010, new safety regulations came into force which introduced new standards for public safety management systems to prevent harm to people and property from electricity and gas supply systems. In response to this a Public Safety Management System (PSMS) has been developed and implemented by Aurora, which provides a framework to:

- report and fix any potential hazards from electricity and gas equipment;
- maintain a hazards register;
- undertake regular audits to confirm compliance with the safety legislation.

Anyone who identifies a potential hazard must report it via existing safety systems. The safety page on Aurora Energy’s website (www.auroraenergy.co.nz.) can also be used by contractors and the public to report potential hazards.

Legacy assets

With long life networks there are inevitably a number of legacy assets that do not meet improved operational or safety standards. When staff become aware of assets or safety issues that do not meet modern expectations, a process to prioritise mitigation measures to reduce the risk to both the general public and staff / contractors is implemented. These actions may include full replacement over time or may include strategies to reduce risk until replacement can be achieved.

Examples of where those types of risk are being managed by Aurora are: zone substation buildings (in terms of fire protection, security and earthquake strengthening), legacy issues related to historic design and management of the central network; glass tube fuses; Andelect fuse boxes and older link-boxes; cast-iron pot heads and poles that are in poor condition preventing safe network operation.

Earthquake prone buildings

The Canterbury earthquakes of September 2010 and February 2011 raised awareness levels of the fragility of a large number of older buildings in New Zealand to withstand earthquake forces. Dunedin is susceptible to similar type damage to older buildings and to utility services in general, not just electricity supply.

Asset planning and emergency response procedures are being developed to take into account this specific risk.

4.5.2 Reliability

Risks that potentially impact on reliability include:

- Loss of staff / contractor capacity and / or capability
- Capacity to meet demand
- Funding for asset development / maintenance
- Skills and knowledge for new assets / restoration of faults
- Access / knowledge of staff / contractors of equipment and process manuals
- Adequacy of asset management programme
- Adequacy of equipment replacement programme

Reliability is a function of:

- equipment duplication, which either avoids an interruption or shortens restoration times (i.e. security of supply);
- asset condition, which affects the likelihood of failure of a component;
- operational practices, which reduce restoration time.

Probabilistic analysis is used for major plant items to determine the likelihood of equipment failure and the consequential effects of lost load.

The probability of failure is assessed by using engineering judgement in considering past and likely future failure rates.

A “deterministic filter” to highlight areas of the network that require further economic analysis is shown in Appendix B.

Expenditure is presently planned to achieve the supply reliability targets set out in Section 3. See Sections 5 and 6 for detail on expenditure for project related to reliability.

Probabilistic analysis is also used to justify small scale projects, such the installation of reclosers to improve SAIDI. Also refer to Section 6 for an outline of the planning criteria used by Aurora.

4.5.3 Quality & Capacity

A key element for planning risk management strategies for assets is an understanding of the short, medium and long term requirements for maintenance of existing assets and the development of new assets.

The capacity requirement for the life of assets needs to address growth (positive and negative as noted in the above list) requirements for the consumer.

Key risks that potentially impact on quality include:

- Growth (negative and positive)
- Supply reliability
- Systems failure or inadequacy (information technology, systems knowledge)
- Loss of facilities
- Legislative / regulatory changes
- Investment in asset development and maintenance
- Third party supplier availability / default / competence
- Lack of standard procedures & work instructions

The following information relates to growth specifically:

Capacity increases to cater for existing and predicted growth are step-like in nature. For example, the provision of the new Commonage substation increased the capacity of the Queenstown CBD and surrounding area by 15 MVA, or 75%. Similarly, the upgrading of the Frankton substation has increased the n-1 capacity in this area by 50%.

Where problems are identified in relation to short-term voltage variations, Aurora works with individual network users to identify and implement the optimum solution.

There is a risk that growth could slow, or stagnate, and lead to a short term view that there has been over-investment in this region. However, given the lead times required under the RMA and the time required for equipment to be sourced from overseas; the risk of non-supply and the resulting consequential effects is greater than that of over-investment and, as such, is the predominate risk to be managed.

Over-capacity due to consumers no longer needing a power supply, or a high capacity power supply is an on-going second order risk. Equipment is relocated if it is economic to do so.

4.5.4 Security

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances where electrical equipment fails or where an incident compromises service delivery. Security of supply differs from reliability which has been addressed earlier in this section.

Key risks that potentially impact on security include:

- Natural disasters
- Critical supplier failure
- Aurora infrastructure failure – poles, substations, generators, lines
- Single-point dependencies
- Staff / contractor availability for extended outages
- Rural isolation of sites
- Reliance on the mobile substation

Providing the acceptable level of security (cost versus the customers 'willingness to pay' to provide a certain standard of security) is part of project planning requirements when developing new assets or considering maintenance requirements for existing assets.

Developing the network to meet future demand growth requires significant capital expenditure. Before spending capital on the network, Aurora considers a number of options including those available in demand side management and distributed generation.

The amount spent on the network is influenced by existing and forecast consumer demand for electricity and the number of new consumer connections to the network. Other significant demands on capital include:

- safety and environmental compliance requirements
- maintaining security of supply standards
- meeting reliability of supply targets.

Supply availability and reliability to zone substations is dependent upon both the security of supply from the five GXPs within the network areas, and the security and level of distributed generation connected into those GXP systems. The following table identifies areas of network security. Waipori generation would be able to maintain supply to the Halfway Bush GXP. The risk of non-supply from Transpower is, therefore, assessed to be very low – even though when this happens the effects are likely to be major.

GXP Area	n-1 Transpower Capacity MVA	Distributed Generation MW	n-1 Security
Halfway Bush	107	95.8	No
South Dunedin	81	2.2	Yes
Clyde	27	23.3	Yes
Frankton	66	3.9	Yes
Cromwell	50	5.5	Yes

Also see Planning Criteria in Section 6.2.

Hazard mapping

Aurora's network has been mapped against the hazard areas identified through work being carried out by the Otago Regional Council as part of lifelines planning. Aurora will be building on this information in 2013/14 through further assessment on:

- Critical sites/routes.
- Risk interdependency issues, including off-grid critical assets.
- Robustness/vulnerabilities to each hazard risk identified.
- High-level preparedness and plans for enhancement and further risk reduction.
- Emergency response dependencies and priorities, especially in relation to other lifelines.

This work will both inform and be informed by the risk management activities discussed in Sections 4.2 - 4.4

4.5.5 Criticality and Network (Asset) Risk Analysis

Over the recent past, Aurora's focus has turned to assessing and understanding critical assets and the risk profile of the distributed electricity network. The approach taken to identify areas of the network that are vulnerable to high impact, low probability events will be further developed in 2013/14 with the outputs contributing to a more robust risk-based approach to asset management and subsequent capital, renewal and operational investment requirements. The following provides a summary of some of the asset and network risks that Aurora is working through. Critical assets that have the potential to give concern, such as the oil and gas insulated 33 kV cables, are closely monitored and will be subject to further investigation and risk assessment. Sections 5 & 6 also contain detail on projects to address these issues.

Poles

Poles are assessed for their condition based on a scale of 0-6, with zero being very bad condition. Condition 0 means an overhead line structures which is 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.

Of the 34,000 wooden poles on Aurora's network, 4% are condition 0. Under the Electricity (Safety) Regulations (2010) these must be repaired or replaced not later than 3 months after finding the risk of failure. Based on this, there are currently 1367 condition 0 poles (as at February 2013) pending replacement, with replacement costs in the order of several millions of dollars. Amongst the 1367 condition 0 poles, some have assets on them that require manual operation or hold other network assets, such as transformers; and some may have assets from other utilities (e.g, Telecom) attached.

At present, funding has been allocated for pole replacement; with a maintenance budget available of \$0.8M per annum; and a renewals budget of \$3M per annum out to 2015/16⁷. Options are being considered for technology to enable direct measurements of pole strength to support revised condition ratings and cost estimates. This is because up to 40% of poles have been labelled condition 0 as a precaution due to constraints on being able to assess the pole thoroughly. Revised condition assessments will assist to rationalise the number of poles requiring replacement within the 10 year planning period

The above will be supplement with the work that Delta is doing to develop and implement a more robust risk assessment framework that collates condition based observations and consequence of failure to produce an asset health index for each structure. This will also assist to improve the risk-based prioritisation process used to inform the replacement and maintenance programmes.

Vegetation Management

Vegetation has been assessed (2011) for proximity to Aurora's lines using a rating of 0-7, with zero being vegetation that represents an immediate danger to person or property through to a rating of 7 where the vegetation has been removed.

Under the Electricity (Hazard from Trees) Regulations 2003, Aurora must attend to the vegetation with a rating of 0 without delay. Based on this rating, there are currently 6,059 condition 0 areas that require cutting, at an estimated cost of many millions of dollars. The budget available for this is currently \$1.3M per annum. Over a third of Aurora's planned maintenance budget has been spent on vegetation management annually to date. Anecdotal evidence suggests there has been apposite improvement in network reliability due to spend in this category, although more time is required to see real trends.

Aurora is working with it's contractors to improve the vegetation management process developing a more robust risk assessment framework which will also assist to improve the risk-based prioritisation process used to inform the vegetation management programme

Zone Substation buildings

Aurora has 36 zone substations and many (particularly in Dunedin) are housed in buildings that are up to 70 years old and likely require significant upgrades given the requirement to ensure buildings are of today's standards. Comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out in 2013/14. Significant investment may be required for earthquake strengthening.

⁷ A holistic approach has been established with financial resources secured to target complete feeders for pole and pole hardware renewal in conjunction with vegetation management – see Section 5 and 6 for further detail.

Capacity risks

The table below combines 4 sets of information: (i) substations potentially at risk of capacity issues in the short, medium and long term based on predicted demands against firm load capacity, (ii) the highest ranked 'load at risk' substations; (iii) substations with the highest percentage of domestic customers potentially affected as a consequence of an outage and (iv) the substations that have priority 1 customers as well as highest number of priority 2 customers within that supply area. Priority 1 customers include organisations such as hospitals and Priority 2 comprise of water/drainage utilities and other emergency service organisation (based on the ANZSIC codes and priorities).

It is clear that, in Dunedin, Andersons Bay, Green Island and Halfway Bush substations reflect critical parts of the network and are therefore presenting as a priority for Aurora to focus on. Halfway Bush GXP area contains most of these substations. In Central, Wanaka, Cromwell, Frankton and Arrowtown are presenting as priority. Altogether, there are 12 zone substations that do not have n-1 security and currently rely on the availability of the mobile substation for back-up in an emergency. This dependency is of concern to Aurora and options to reduce this risk are being considered. See Section 6 for projects proposed to address these issues.

GXP area	Capacity Issues	Load at Risk MW range (6-18)	% Domestic ICP's (70-95%)	Priority 1 and 2 ICP's (ANZSIC)
Clyde	Omakau	Alexandra		
Cromwell	Cromwell, Queensberry, Wanaka, Maungawera	Wanaka, Cromwell	Wanaka	
Frankton	Arrowtown Dalefield, Frankton, Remarkables	Frankton, Commonage, Arrowtown, Queenstown	Arrowtown, FernHill	
Halfway Bush	Smith Street ,Halfway Bush	Port Chalmers, Green Island	Green Island, Halfway Bush, NEV, East Taieri,	Halfway Bush, Green Island, East Taieri, Kaikoari Valley, Smith Street, Willowbank
South Dunedin	Andersons Bay, South City	Andersons Bay, North City	Andersons Bay, Corstophine, St Kilda	North City

Within the HV and LV distribution network there are also particular single-point dependency sites that only have one source of incoming supply. When failures occur on these parts of the network, mobile generators are required to assist with providing back-up supply, at a cost to Aurora (as they are leased). This dependency is another concern to Aurora and options to mitigate this may include purchase of a mobile generator.

Interdependence with other services

Many service organisations rely on the services of others to perform. In particular communication systems are of critical importance to all lifeline utilities. It is important to understand this interdependence in the recovery phase of any natural disaster or event that triggers a major business interruption.

As a member of the Otago Engineering Lifelines Group, Aurora recognises the importance of being part of a wider lifelines network to contribute to regional planning, preparedness and response capability.

4.6 Business Risks

4.6.1 Strategic

The operating environment for Aurora will remain challenging in the face of uncertain economic conditions and on-going pressure on local government expenditure.

Key issues that Aurora faces in the short / medium future include:

- Development and growth leading to demand growth (or lack of growth)
- Global influences on pricing / costs and service standards
- Investment and affordability – business competition; aging infrastructure
- Significant investment in upgrades and replacement
- Customer affordability for services and development requirements
- Cleaner energy
- Smarter energy

- Changing energy requirements – alternatives to electricity
- Changing shareholder (Council), regulatory and government environment (local and central government)
- District and Regional Planning documents – development controls, enforcement of consents
- Geographic spread of operational locations - isolation
- Safety – injury / death related to the asset development and delivery of services
- Organisational capability and capacity
- Natural disasters and climate changes – e.g. lake storage levels

Property Related Risk – Leased Land / Easements

Aurora lease land for radio sites and other network related uses. Rent reviews could significantly increase the cost of leasing land. For future security of land required currently under lease Aurora needs to consider whether a property purchase programme is needed to secure the land and ensure financial security.

Aurora has a number of easements for network services particularly over land owned by the Dunedin City Council (the shareholder). Council has started to charge a one off fee for future easements; and depending on the size of the easements, these costs are potentially significant. Aurora needs to consider other mechanisms such as designating the land in the District Plan.

4.6.2 Compliance

A key risk to Aurora is non-compliance with legislative and regulatory requirements. Aurora aims to achieve material compliance with all relevant legislation, regulations, standards and codes of practice that relate to how the electricity distribution network is managed and maintained, including any relevant environmental legislation. A list of the main pieces of legislation is provided in Section 2.4 and Aurora's business/quality management system provides the tool to ensure compliance is monitored and achieved. The following on provides further commentary.

Environmental

Aurora's policy is to act in an environmentally responsible manner, and as required under legislation.

The Resource Management Act is the major legal driver. The provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise, and the duty to avoid, remedy or mitigate any adverse effect on the environment are of particular relevance.

The Local Authority District Plan requires appropriate consents for new work, and requires management systems (mainly for environmental and public safety issues) in relationship to existing works. Aurora develops practices on the basis of being a reasonable and prudent operator, to ensure that both environmental and public safety issues have been addressed.

The main environmental risk from Aurora operations is the accidental discharge of insulating oil into waterways. Oil spill kits are provided at all zone substations, and contractors are required to carry oil spill kits in vehicles used to transport oil filled equipment. Where practicable, zone substations have adequate bunding to contain potential oils spills.

The use of equipment with SF6 is actively discouraged where economic alternatives exist, due to its potential to act as an ozone depleting agent if it is accidentally released into the atmosphere. However, it is noted that SF6 used for Aurora's distribution switchgear is likely to increase in response to the existing oil-based options being discontinued.

Disclosure Requirements & Price-Quality

Aurora is subject to regulation under Part 4 of the Commerce Act 1986, for price-quality regulation and information disclosure. As such, Aurora is required to provide an audited self-assessment (compliance statement) to the Commerce Commission against the DPP on an annual basis as well as disclose other information related to asset management (performance statements) and other measures such as financial statements, through to technical measures such as transformer utilisation. See the Aurora website for more detail.

In 2012, the Commerce Commission published new determinations for information disclosure requirements (these supersede the 2008 requirements). This AMP has been revised from earlier versions to align with the regulatory requirements of the new Electricity Information Disclosure Determination 2012 and provides more comprehensive

information on for Aurora's asset management practices and expenditure forecasts; (see Appendix C for compliance matrix).

Civil Defence

Aurora is defined as a utility under the Civil Defence Emergency Management Act and is required to ensure that it can operate to the fullest extent even if at a reduced level, during and after an emergency. Delta staff have roles within the Civil Defence structures in Otago. Delta staff take part in Civil Defence exercises as required.

Other

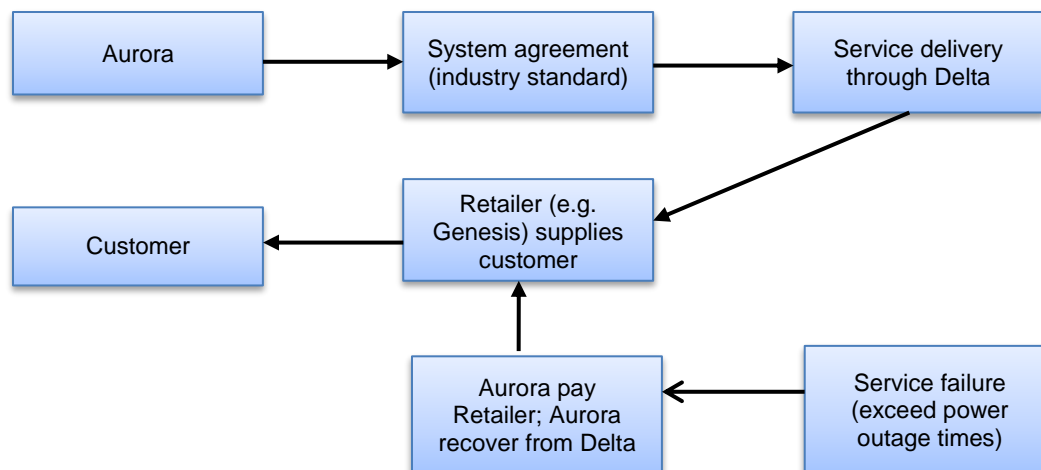
Recommendations from the Royal Commission report into earthquake-prone buildings and seismic strengthening may lead to changes in building legislation and related requirements are already driving the need for Aurora to allocate expenditure (e.g. zone substation buildings).

4.6.3 Commercial

Key commercial risks that Aurora has identified include:

- Finance
- Pricing
- Insurance
- Contracts
- Industry Submissions
- Optimisation & Sustainability

Section 3.2.4 discussed responsiveness and service failure payments. Aurora has agreements with retailers in terms of the supply of energy. The following diagram illustrates the linkages:



Use of System Agreement

Customer Service (Reputation)

Some of the risks that potentially impact on reputation and service include:

- Damage to Aurora assets by third parties affecting supply of power
- Speed of response to incidents / outages
- Staff / contractor skills and knowledge
- Customer-relations
- Not meeting level of service commitments

Customer / stakeholder interests are addressed in detail in Section 2.3 and 2.4 of this AMP.

Feedback has been sought from both customers and stakeholders through surveys, open requests for feedback, safety reviews, industry forums, and through day to day customer engagement (e.g. phone complaints).

4.6.4 Human Resources

In reviewing the progress of capital works, in particular over the three years, the ability of the supply industry to meet what have been historically reasonable deadlines has declined. Consulting staff are not as available as they have been in the past, and equipment procurement, particularly power transformers, requires long lead times as mentioned in recent AMPs.

The risk of not obtaining adequate competent human resources for timely design and construction is an industry-wide risk. Longer lead times are, therefore, required to minimise the possibility of industry peak workloads causing unacceptable pricing of works. This situation, compounded with the need to design and order items such as power transformers before finishing detailed design such as substation layouts required for resource consent, with its own possibility of objector delays is creating further uncertainty of being able to complete projects on time.

4.6.5 Information & Process

Information and Technology Services and Equipment

Key risks have been identified in the areas of:

- Information services equipment (hardware and software)
- Telephony equipment
- SCADA
- Site information e.g. underground wiring plans

A key dependency of all staff in delivering service is access to reliable, effective and efficient information and technology services and equipment. This includes access to systems and data. A disaster recovery plan for IT related information and services that has been deployed and tested in the past.

Risk Programme

The risk management programme includes information and processes for the risk policy and framework, risk register, risk data collection sheet, and risk reporting.

Further work is planned for 2013 to continue to develop the risk register, risk assessment and information analysis, and risk reporting.

Post Incident Reviews

A process has been developed and implemented to undertake reviews after incidents that cause the activation of the business continuity plan or where the incident has a high potential or actual impact on Aurora services

The incident review process includes hot debriefs, cold debriefs and incident reports.

A report is provided on the findings of the review. Depending on the type of incident and the findings of the review the report may be reported to a line manager, general manager, Chief Executive, Audit and Risk Committee or the Board.

4.7 Risk Mitigation

4.7.1 Procedures and Plans

A risk management framework and implementation plan has been developed to identify and address risks to the business.

A risk register has been developed to capture data on each risk, any existing controls to treat the risk, the consequence and likelihood of the risk and a treatment plan summary.

The risk register is supported by a more detailed risk assessment worksheet that is designed to capture more detail about the risk including the effectiveness of current controls and the risk action plan for that particular risk.

Risk management documents developed include:

- Pandemic Planning
- Risk Management Policy
- QN20, Risk Management for Electricity Networks
- QP2001, Civil Defence Policy re Electricity Supply
- QP2002, Emergency Preparedness Plan
- QP2003, Emergency Communications policy

4.7.2 Business Continuity and Emergency Response Planning

Emergency response planning is based on the concepts of the Four “R’s” used by emergency services, Civil Defence Emergency Response Organisations and many utility operators in New Zealand. This terminology is included in readiness and response documentation and training.

The Four “R’s” are:

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 – The coordination of the organisation (and potentially external organisations) to return the business to full capability (recovery can take weeks, months or years depending on the severity of the incident e.g. Canterbury earthquakes).

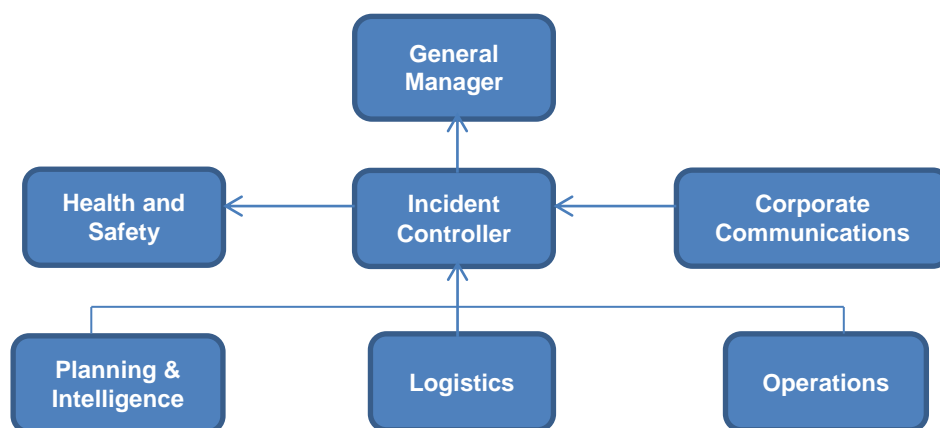
The company has a business continuity programme in place to respond to major incidents. The programme includes:

- Business continuity plan for response
- Response guide for use in an incident
- Responder training
- Plan exercise and testing programme to demonstrate capability and competence.

Operational incidents (e.g. asset breakage) are part of normal business operations and staff are trained to deal with those day to day situations as part of their training and development plans.

For major incidents business continuity planning is in place to respond to those incidents.

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 to respond on site and escalate incidents to senior management. The model is:



Coordinated Incident Management System Model

Aurora's contractor, Delta, responds regularly to routine emergencies, such as network system outages. Restoration of supply is co-ordinated via the System Control Centres, which are staffed during normal business hours. After hours, standby rosters are in place with the on-duty Controller attending the Control Centre as necessary. Standard Operating Procedures are covered in a variety of quality control documents including QP1601, QP1602, QP1603, QP1604, QP1605, QP1606, QP1607 and QP1609.

Civil Defence

Civil Defence Emergency Management Act

Aurora is defined as a utility under this Act and is required to ensure that it can operate to the fullest extent even if at a reduced level, during and after an emergency.

A plan is in place for response to emergency situations and for liaison with local Civil Defence organisations for the effective use and co-ordination of resources within Aurora's electrical supply area in emergencies. The details are in documents QP2001 Civil Defence and QP2002 Emergency Preparedness Plan. These documents are updated every two years. Aurora has installed a generator at the Cromwell base to enable this hub, like Dunedin, to be fully operational during an emergency. Satellite phones are kept at these hubs and Queenstown for emergency use.

Staff also have roles within the Civil Defence structures in Otago and take part in Civil Defence exercises as required. Several Delta staff assisted in damage assessment activities immediately after the September 2010 Christchurch (Darfield) earthquake and have passed on lessons learnt to key staff.

Contingency Plans

Contingency plans have been developed 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 offload peak loads at most substations for potentially rare "n-2" events; i.e. transfer a complete substation's load for a combined failure, such as both subtransmission circuits or both transformers at the larger substations. Reviews of how well the plans worked during major events have been completed within the last 2 years.

Other contingency plans include: QP1501, Oil Spill Control; Incident Reporting and Investigation

A Participant Outage Plan details how Aurora would manage severe energy shortages if the Electricity Commission declared that savings are required.

4.7.3 Conclusion

This section has highlighted the main network and business risks related to Aurora's activities. The following sections cover the lifecycle management practise and programmes as well as network development projects that are planned to minimise or mitigate many of these risks.

5 Life Cycle Asset Management

5.1 Introduction

The following section provides an overview of Aurora's network, details of the assets by asset category, the approach taken for management throughout their life cycle and associated expenditure forecasts.

5.2 Network Overview

An assets lifecycle commences with the identification of the need for an asset and terminates with the decommissioning of the asset or any liabilities thereafter (IIMM, 2011⁸). Aurora manages electricity assets throughout their life cycle in three geographically separate networks (Dunedin, Central Otago and Te Anau), with both rural and urban characteristics, as shown in Figure 5.1 below. Delta operates the network, carries out network planning and develops the maintenance plans and programmes on behalf of Aurora; and Aurora is committed to enabling the implementation of these.

Approximately 60% of Aurora's overhead circuit length is located in rural/rugged terrain and approximately 40% in urban areas.

- The Dunedin network includes - urban areas of Dunedin, Mosgiel, and the inner reaches of the Taieri Plains, supplying 53,777 customer connections. The Dunedin area is supplied from two Grid Exit Points (GXPs), between which Aurora has significant interconnection at 6.6 kV and 11 kV.
- The Central Otago network - stretches from Raes Junction in the south to Lakes Wakatipu and Wanaka in the north-west, and St Bathans and Makarora in the north-east; and supplies 29,050 customer connections. The Central region is characterised by its separate river valley areas, mandating a radial network supplied from three transmission GXPs. Aurora has no high voltage interconnections between the Central GXPs.
- A small embedded network, connected to The Power Company network, was installed in Te Anau in 2005; and supplies 81 customer connections.



Figure 5.1 – Aurora Network

⁸ NAMS and IPWEA (2011) International Infrastructure Management Manual v4.0

Large Consumers

The largest consumer within the Dunedin network that has a significant impact on network operations is the University of Otago with a peak load of 5 MW. In Central Otago, the consumers that have the most significant effects on the network are the ski fields (e.g. Coronet 4.4 MW) (also see Section 3.1.1)

Load Characteristics

The load in all areas is dominated by residential and commercial load. All GXP areas have their peak demand in winter. For each GXP the daily peak loads for 2012 are shown in Figure 5.2.

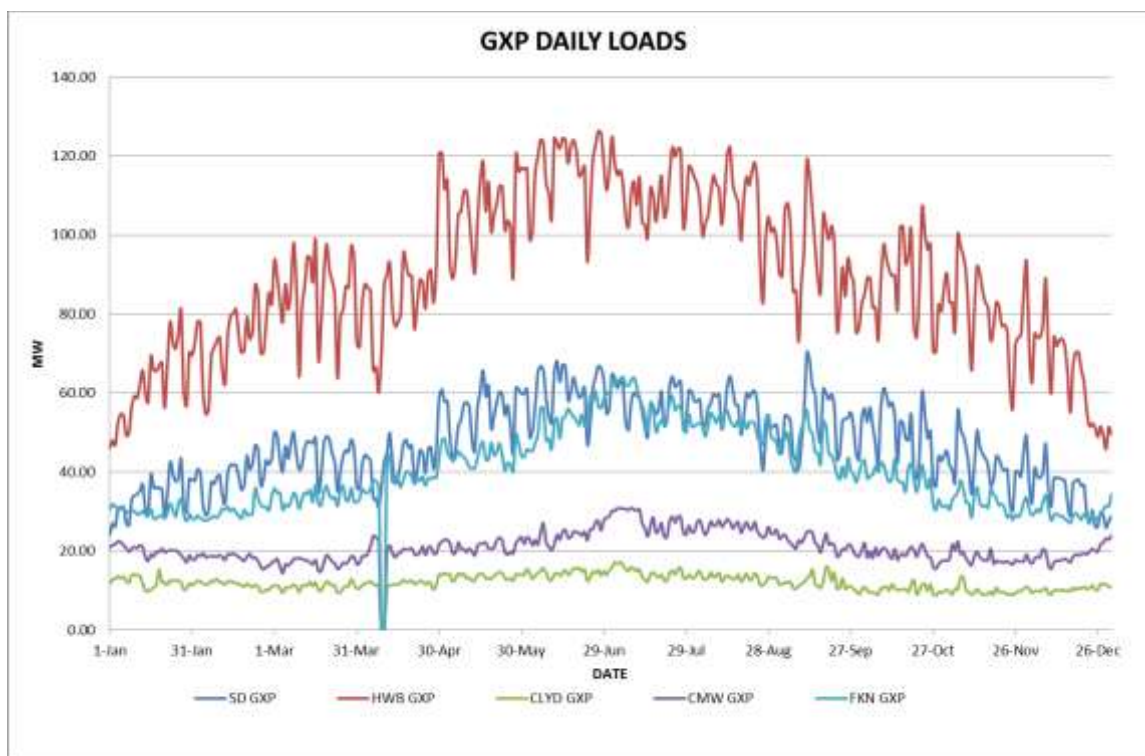


Figure 5.2 – Graph of Grid Exit Point Daily Load Peaks (2012)

The Frankton and Cromwell GXP peak loads usually occur during the July school holidays, due to the influx of skiers into the area, which drives three components of demand – ski field load, normally vacant holiday houses are occupied, and hotels, motels and café's experience higher occupancy. There has been significant growth in summer irrigation load on the Cromwell GXP leading to summer peaking at the Queensberry zone substation.

The Clyde GXP serves Alexandra, Roxburgh, and surrounding areas, with load also peaking in winter. In some areas supplied from Clyde (such as Omakau, Roxburgh and Ettrick), orchard frost-fighting pumps put a large demand on the system for a short time during September and October.

Dunedin peak loads are very weather dependent and generally occur during a snowfall event in the city which can be anytime from May to September. A peak load event is unlikely to occur during school holidays or at a weekend. The Dunedin load has a larger variation between weekend and week day loads than that observed in Central – due to a higher proportion of industrial and commercial load. However, the Berwick Zone substation load is driven by dairy activities and as such has summer peaking.

Sections 6.3 and 6.5 contain further detail on demand forecasting and predictions.

2012 Load Data

The key load and distributed generation statistics for the 2012 year are presented in Table 5.1

Table 5.1 – GXP Load and Capacity Summary

(y/e 31 March 2012)

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2012 peak MW including distributed generation	16.4	29.9	48.7	128.7	72.2	
2012 energy transported GWh	82	134	217	594	310	1338
Total number of ICPs	6,663	10,574	11,813	36,922	16,855	82,524
Off take n-1 capacity (24 hour winter post contingency) MVA	27	40.9	80	112	81	

Distributed Generation

Aurora has a total of 130.9 MW of distributed generation connected to its networks. 118 MW is associated with generation dedicated to export and 12.9MW is associated with consumer installations connected behind load. See Table 5.2 for a schedule of distributed generation by GXP and owner. Table 5.3 provides a summary by energy source.

Most consumer generation is diesel powered with the primary purpose of providing a standby supply, but can be operated in parallel with the Aurora network to reduce congestion period demand (CPD). There is a small quantity of consumer photovoltaic (PV) generation, a single small wind generator and two micro hydro connections. In the last year there has been a marked increase in applications to install small domestic PV units.

Table 5.2 – Schedule of Distributed Generation Dedicated to Export

(y/e 31 December 2012)

GXP	Generation Owner	kW
Clyde	Consumer	77
	Pioneer Generation Ltd	21,125
	Talla Burn Generation Ltd	2,150
Clyde Total		23,352
Cromwell	Consumer	2,021
	Pioneer Generation Ltd	3,550
Cromwell Total		5,571
Frankton	Consumer	1,828
	Pioneer Generation Ltd	2,131
Frankton Total		3,959
Halfway Bush	Consumer	6,658
	TrustPower	89,200
Halfway Bush Total		95,858
South Dunedin	Consumer	2,168
Grand Total		130,907

Table 5.3 – Summary of Distributed Generation Behind Consumer Load

(y/e 31 December 2012)

Energy Source	Count	Rated kW	Proportion
Hydro	23	79,873	61.0%
Wind	5	38,302	29.3%
Diesel	18	10,033	7.7%
Process heat	1	2,240	1.7%
Wood	1	230	0.2%
PV	58	229	0.2%
Total		130,907	100.0%

5.2.1 Dunedin Network

The Dunedin network area is supplied from the Halfway Bush and South Dunedin GXPs at 33 kV. There are 19 feeder outlets at Halfway Bush and 11 at South Dunedin (one spare). The main Dunedin urban area is supplied by transformer-feeder zone substations, with each substation having two 33/6.6 kV transformers. The North East Valley zone substation is teed off the Port Chalmers zone substation 33 kV circuits. The Taieri Plain area, including Mosgiel, is served by four zone substations which are supplied from the three parallel 33 kV lines between the Halfway Bush GXP and the TrustPower's Waipori power scheme. An overview of the network is shown in Figure 5.3 and zone substation details are in Table 5.4.

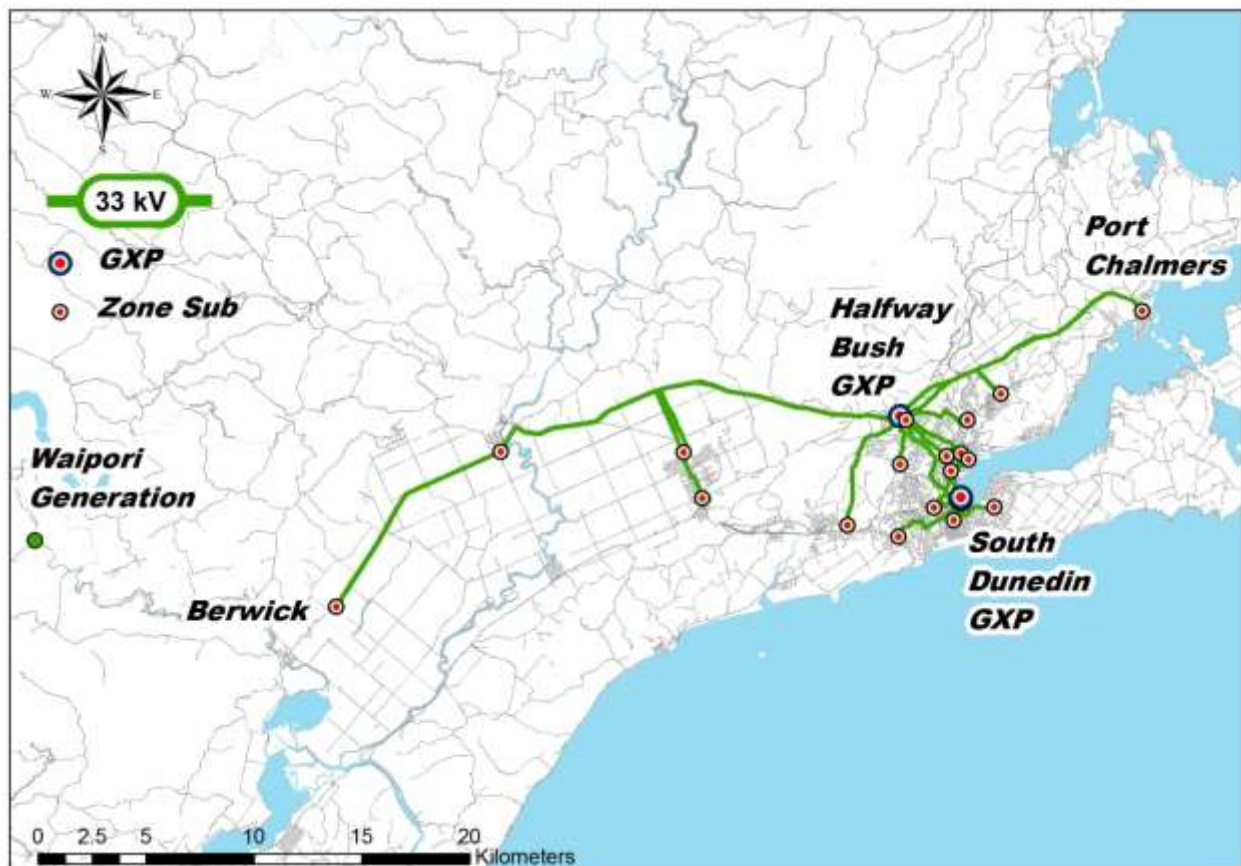
**Figure 5.3 – Dunedin Subtransmission Network**

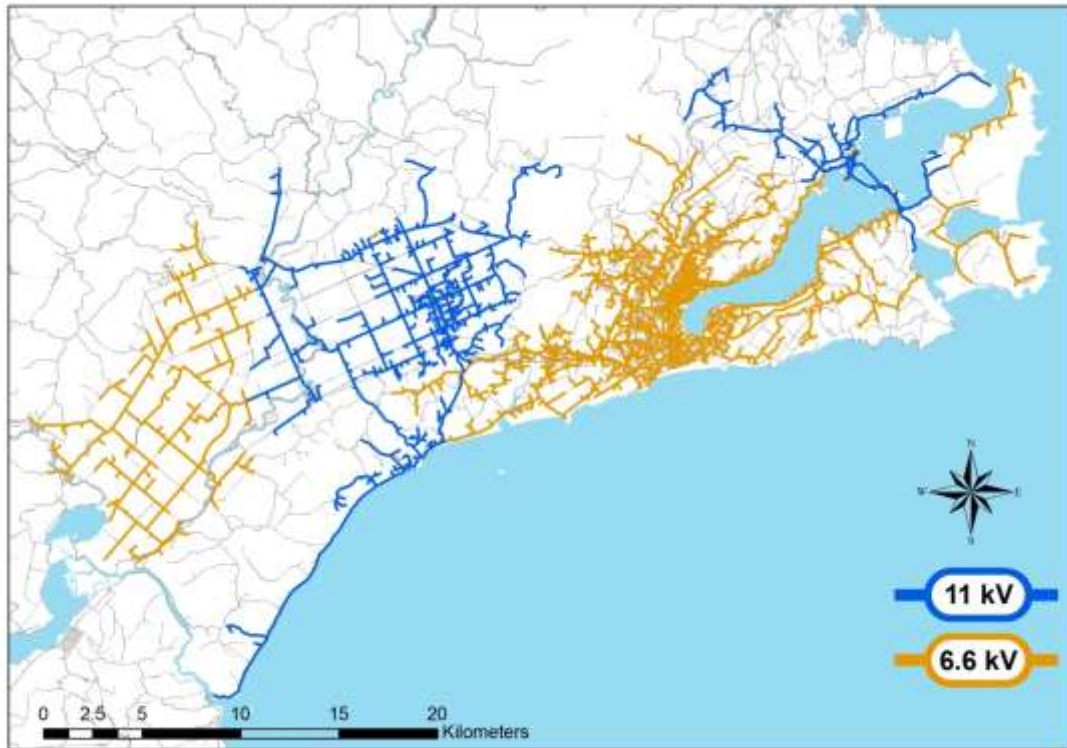
Table 5.4 – Zone Substations in the Dunedin Area

Grid Exit Point	Zone Substation	Transformer Capacity MVA	Subtransmission	n-1 Security
Halfway Bush	Berwick	3	Selectable to any of the three Taieri 33 kV subtransmission lines	N
	East Taieri	12/24 + 12/24	Two 33 kV oil cables via Mosgiel and Taieri subtransmission circuits	Y
	Green Island	15 +15	Two 33 kV lines from HWB GXP	Y
	Halfway Bush	17/24 +17/24	Two PILC cables from HWB GXP	Y
	Kaikorai Valley	24 +24	Two PILC cables from HWB GXP	Y
	Mosgiel	10 +10	Selectable to any of the three Taieri 33 kV subtransmission lines	Y
	Neville Street	15 +15	Two gas cables from HWB GXP plus a PILC tie cable to Ward Street	Y
	North East Valley	9/18 + 12/18	Two 33 kV lines and PILC cable circuits teed off Port Chalmers lines	Y
	Outram	3 +3	Selectable to any of the three Taieri 33 kV subtransmission lines	Y
	Port Chalmers	7.5 +7.5	Two 33 kV lines from HWB GXP	Y
	Smith Street	15 +15	Two 33 kV gas cables from HWB GXP	Y
	Ward Street	12/24 + 12/24	Two 33 kV gas cables from HWB GXP plus a tie cable to Neville Street	Y
	Willowbank	15 +15	Two 33 kV gas cables from HWB GXP	Y
	Andersons Bay	15 +15	Two 33 kV gas cables from Sth Dn GXP	Y
South Dunedin	Corstorphine	12/24 +12/24	Two 33 kV oil cables from Sth Dn GXP	Y
	North City	14/28 + 14/28	Two 33 kV oil cables from Sth Dn GXP	Y
	South City	9/18 + 9/18	Two 33 kV oil cables from Sth Dn GXP	Y
	St Kilda	12/24 +12/24	Two 33 kV oil cables form Sth Dn GXP	Y

Dunedin Network – HV Distribution

HV distribution in the Dunedin area is via 187 HV feeders. Four zone substations; Mosgiel, East Taieri, Outram and Port Chalmers have 11 kV feeders and the remaining fourteen have 6.6 kV feeders. The HV distribution voltage by location in Dunedin is shown in the map below.

All feeders are radial with a high degree of meshing in the metro areas, except for the supplies to Otago University and the Hillside Workshop site which have dedicated paralleled feeders. There is an additional 9 km of 11 kV SWER that supplies the north western extremity of the Dunedin HV network. All new transformers installed are dual ratio 11/6.6 kV to facilitate eventual conversion to 11 kV.



Dunedin HV Distribution by Voltage

5.2.2 Central Network

The Central network is supplied via Frankton, Cromwell and Clyde Grid Exit Points. Further detail on these areas is provided in the sections that follow.

Frankton

The Frankton area is supplied via seven 33 kV feeder outlets from the Frankton GXP. Two circuits supply the Wakatipu Basin via a ring, and there are three parallel lines from Frankton to Queenstown. A further two circuits supply the Frankton zone substation. A tee off the Wakatipu Basin ring supplies the Remarkables ski field and the Wye Creek generating station (see Figure 5.4 and Table 5.5).

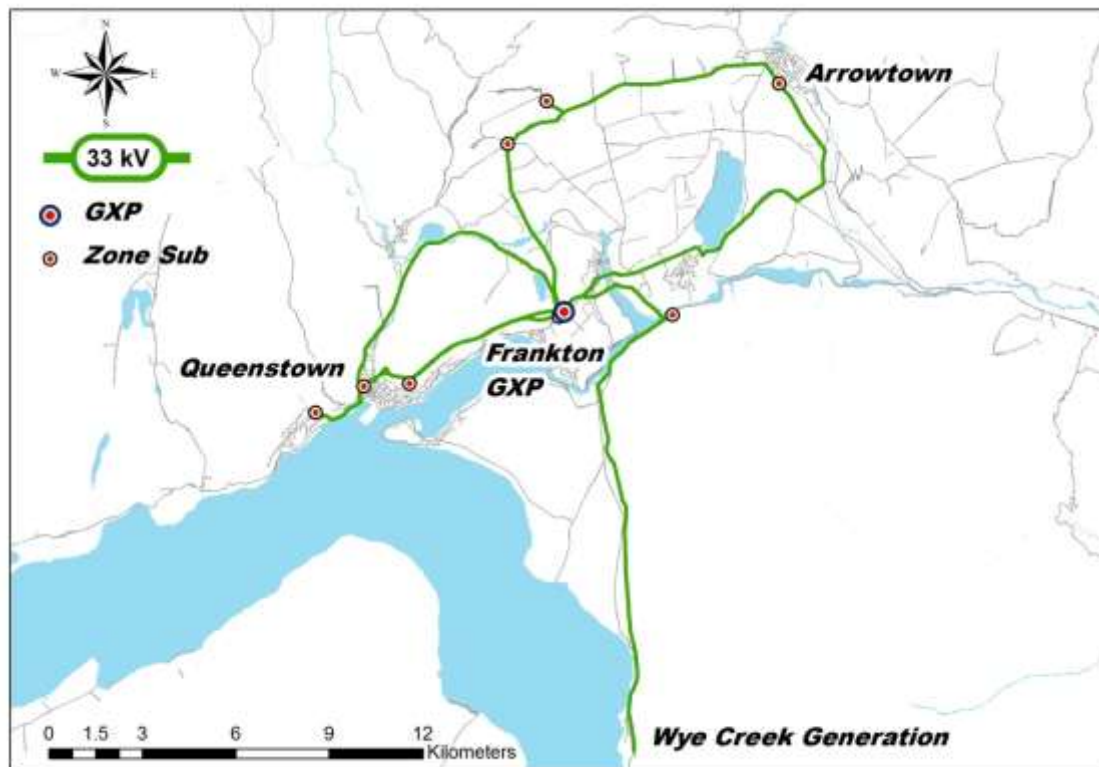


Figure 5.4 – Frankton Subtransmission Network

Table 5.5 – Zone Substations in the Frankton Area

Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Arrowtown	5 + 5	Supplied from Wakatipu Basin 33 kV ring	Y
Dalefield	3	Supplied from Wakatipu Basin 33 kV ring	N
Queenstown	10/20 + 10/20	Three 33 kV lines from Frankton GXP	Y
Commonage	15/17 + 15/17	Two 33 kV lines from Frankton GXP	Y
Fernhill	10 + 10	Two 33 kV XLPE cables from Queenstown	Y
Frankton	12/24 + 7.5/15	One 33 kV XLPE cable and one 33 kV line from Frankton GXP	Y
Remarkables	3	Tee off from Wakatipu Basin 33 kV ring	N
Coronet Peak	5	Tee off from Wakatipu Basin 33 kV ring	N

Cromwell

The Cromwell area is supplied via four 33 kV feeder outlets at the Cromwell GXP. Two of the circuits supply two Aurora-owned, 33/66 kV, 30 MVA, auto transformers, adjacent to the GXP, which supply the Wanaka area via two parallel 66 kV transmission lines. The other two circuits supply the Cromwell zone substation, and provide a connection to the Roaring Meg generation. The transformers at Wanaka are three winding, 66/33/11 kV units, with the 33 kV windings supplying the Maungawera and Cardrona zone substations (Figure 5.5 and Table 5.6)

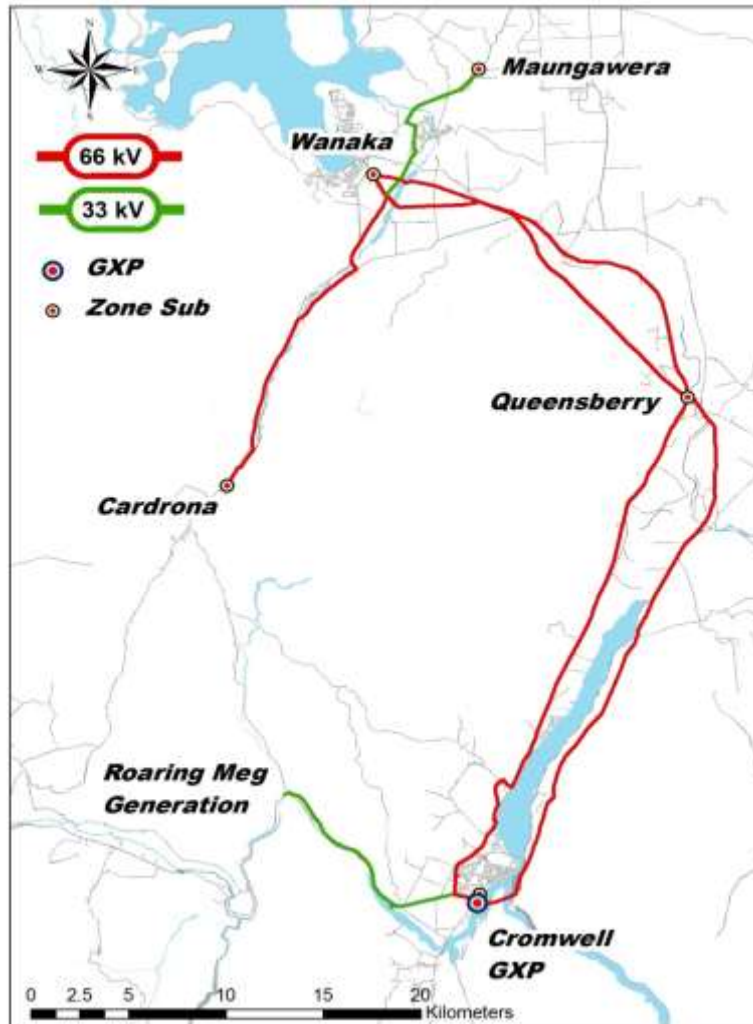


Figure 5.5 – Cromwell Subtransmission Network

Table 5.6 – Zone Substations in the Cromwell Area

Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Cromwell	7.5 + 5/10	One 33 kV line and one cable from Cromwell GXP	Y
Queensberry	3	Tee from either Wanaka to Cromwell 66 kV lines	N
Wanaka	30/10/24 + 30/10/24	Two 66 kV lines from Cromwell GXP with isolated sections of 66 kV cable	Y
Maungawera	3	Single 33 kV line from Wanaka	N
Cardrona	5	Single 33 kV line tee from Wanaka to Maungawera Line	N

Clyde

The Clyde area is supplied via two 33 kV feeder outlets at the Clyde GXP. These circuits supply Alexandra via a parallel pair of overhead lines. A significant amount of the Clyde area load is supplied from the Teviot, Horseshoe Bend and Fraser generation stations. There are two parallel 33 kV lines between Alexandra and Roxburgh that deliver generation output to Alexandra from the South, Omakau to the north-east of Alexandra and Ettrick to the south of Roxburgh with Omakau and Ettrick supplied by a single 33 kV line. An overview of the network is shown in Figure 5.6 and zone substation details are in 5.7.

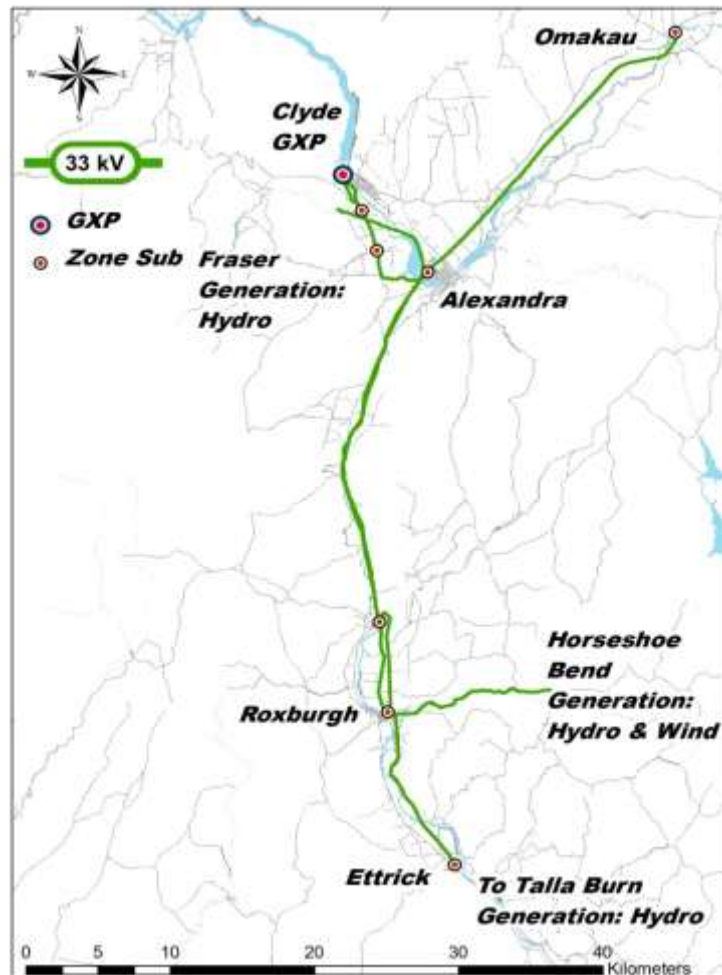


Figure 5.6 – Clyde Area Subtransmission

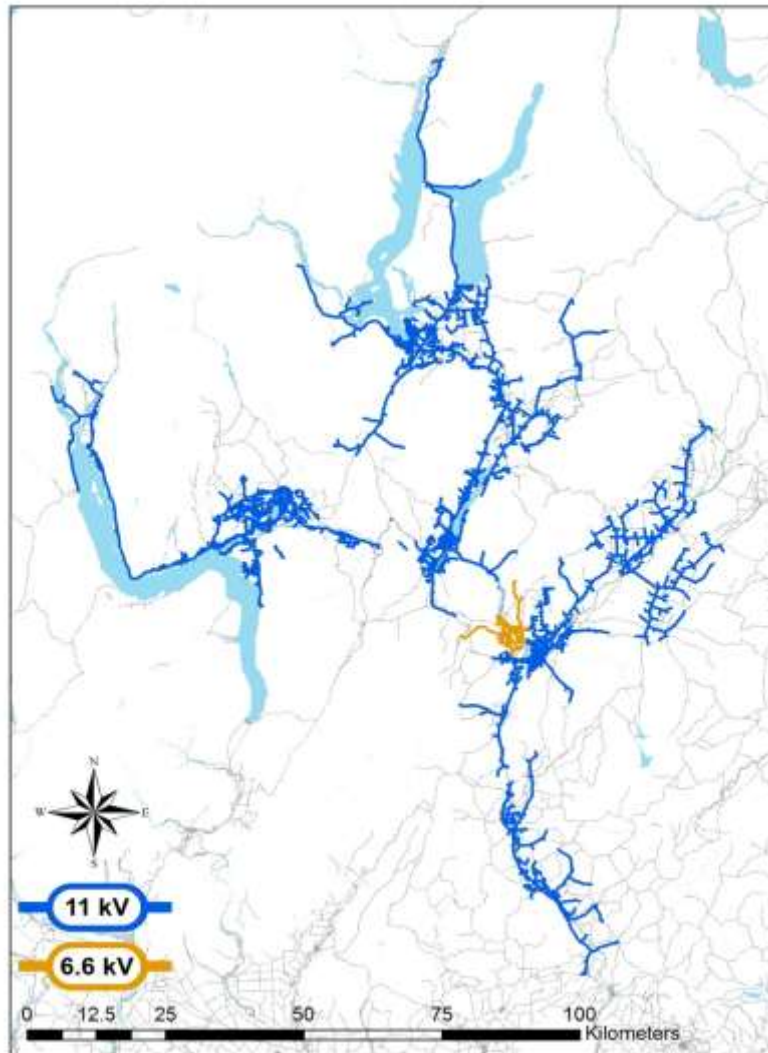
Table 5.7 – Zone Substations in the Clyde Area

Zone Substation	Transformer MVA	Subtransmission Configuration	n-1 Security
Ettrick	3	Single 33 kV line from Roxburgh	N
Roxburgh	1.5**	Via two 33 kV lines from Alexandra	N
Alexandra	7.5/15 + 7.5/15	Two 33 kV lines to Clyde GXP	Y
Omakau	3	Single 33 kV line from Alexandra	N
Earnsclough	2	Tee off Alexandra to Clyde No. 1 33 kV line	N
Clyde/Earnsclough	2 + 5/4	Tee off Alexandra to Clyde No. 2 33 kV line	N

**** Roxburgh Zone Station** is in the process of being converted from a 2 x 1.5MVA Transformer configuration to a single 5MVA Transformer, with a spare bay for a Mobile substation to be connected installed as and when required. While n-1 security does not exist as a permanent feature, the flexibility to install a mobile substation has been added. During the construction period the Mobile Substation is on site along with Roxburgh Hydro Zone Substation (1 x 1.5MVA Transformer) being reinstated for a finite period.

Central Network - HV Distribution

HV distribution in the Central area is via 73 feeders. All HV feeders are 11 kV except for those in the Clyde area which are 6.6 kV. All feeders are radial with limited interties to other feeders. The HV distribution voltage by location is shown in the map below as are the quantities by voltage. HV cable insulation in the Central area is predominantly XLPE, with some PILC. In Central, there is a significant quantity of rural HV cable, due to local authority requirements and the high number of rural lifestyle subdivisions.



Central HV Distribution by Voltage

Central HV Distribution Quantities

Voltage	% Overhead	% Underground
11 kV	26	74
6.6 kV	15	85
Total	26	74

5.3 Asset Details by Category

The quantity and value of Aurora's assets by category (based on the information provided for the 2012 Electricity Distribution (Information Disclosure) Requirements) is presented in Table 5.8 and 5.9. Further information on age, condition and performance is provided in the following section. See Section 2.4 for comments on data completeness and accuracy.

Table 5.8 - Asset Categories and Quantities

Voltage	Asset category	Asset class	Units	Quantity
All	Overhead line	Concrete poles / steel structure	No.	19,833
		Wood poles	No.	33,392
		Other pole types	No.	537
HV	Subtransmission			
	Subtransmission line	Subtransmission OH up to 66kV conductor	km	513
	Subtransmission cable	Subtransmission UG up to 66kV (XLPE)	km	16
		Subtransmission UG up to 66kV (oil pressurised)	km	25
		Subtransmission UG up to 66kV (gas pressurised)	km	41
		Subtransmission UG up to 66kV (PILC)	km	12
	Zone substation Buildings	Zone substations up to 66kV	No.	27
	Zone substation switchgear	22/33kV CB (Indoor)	No.	15
		22/33kV CB (Outdoor)	No.	35
		33kV Switch (Pole Mounted)	No.	194
		50/66/110kV CB (Outdoor)	No.	3
		3.3/6.6/11/22kV CB (pole mounted)	No.	27
		3.3/6.6/11/22kV CB (ground mounted)	No.	334
	Zone substation	Zone substation transformers	No.	67
HV	Distribution			
	Distribution line	Distribution OH open wire conductor	km	2,326
		SWER conductor	km	9
	Distribution cable	Distribution UG XLPE or PVC	km	478
		Distribution UG PILC	km	424
		Distribution submarine cable	km	1
	Distribution switchgear	3.3/6.6/11/22kV CB (PM)-reclosers and sectionalisers	No.	43
		3.3/6.6/11/22kV CB (Indoor)	No.	17
		3.3/6.6/11/22kV Switch and fuses (pole mounted)	No.	6,328
		3.3/6.6/11/22kV Switch (ground mounted)	No.	439
		3.3/6.6/11/22kV RMU	No.	1,031
	Distribution transformer	Pole mounted transformer	No.	4,202
		Ground mounted transformer	No.	2,438
		Voltage regulators	No.	37
	Distribution substations	Ground mounted substation housing	No.	2,438
LV	Low Voltage			
	LV line	LV OH Conductor	km	1,037
	LV cable	LV UG Cable	km	825
	LV streetlighting	LV OH/UG Streetlight circuit	km	1,269
	Connections	OH/UG customer service connections	No.	84,609
Secondary assets	Secondary assets			
	Protection	Protection relays (electromechanical, solid state and numeric)	No.	474
	SCADA and communications	SCADA and communications equipment including single systems	No.	118
All				
	Capacitor banks	Capacitors including controls	No.	6
Other assets	Other			
	Load control	centralised plant	Lot	6
	Load control	Relays	No.	2,195

Table 5.9 – Asset value by Category

Asset Category	RC	% by \$
Subtransmission	\$56,225,175	8.6%
Zone substations	\$106,405,460	16.3%
Distribution and LV lines	\$138,766,783	21.3%
Distribution and LV cables	\$193,748,491	29.7%
Distribution substations and transformers	\$97,288,303	14.9%
Distribution switchgear	\$54,025,963	8.3%
Other	\$6,466,821	1.0%
Total (rounded)	\$652,927,000	100%

5.4 Lifecycle Policies and Strategies

This section covers key information on maintenance, replacements/renewals and new capital across Aurora's asset categories. For clarification, the following expenditure definitions are provided:

Maintenance/Operational Expenditure - Ongoing day to day work required to keep the asset serviceable and prevent premature deterioration or failure. The main categories of maintenance are Service Interruptions and Emergencies, Routine and Corrective Maintenance and Inspection; and Vegetation Management. This also includes expenditure for minor renewals/replacements.

Renewal Capital - Major works that do not increase the asset's design capacity or performance capability (to deliver its original level of service or agreed alternative) but restore, replace or renew an existing asset to its original capacity and therefore may include the complete replacement of an asset that has reached the end of its life. Section 6 also contains detail on the major renewals projects.

New/Growth Capital (Asset Creation/Acquisition) - Capital work that creates a new asset or improves an existing asset beyond its existing capacity. This may be driven by a change in demand or generation on a part of the network resulting in the need for extra capacity or additional investment to maintain current security and/or quality of supply standards due to increased demand. Section 6 contains detail on projects related to network development.

5.4.1 Maintenance Policy and Strategy

5.4.1.1 Policy

The maintenance policy for Aurora's network sets requirements associated with maintenance and refurbishment of electricity network assets. This policy requires Aurora's contractors, Delta, to prepare maintenance plans and programmes for all asset categories, maintain records, carry out analysis, manage contractors, ensure resources are available and effective work management systems are established.

5.4.1.2 Strategy

Aurora's maintenance strategy is based on monitoring of asset condition to balance the risks. Aurora network maintenance is conducted in line with the risk management policy described in Section 4 and is reflective of customer, community, legislative requirements and efficiency drivers, which act against the background of safety and environmental responsibility in addition to fulfilling Aurora's business objectives. Effective maintenance management involves balancing these with the cost of maintenance against the cost of replacement, after including the consequences of failure in both scenarios.

Routine procedures for maintenance specific to each asset category have been developed. These define the frequency of servicing/inspection and the scope of work that must be covered. They are based on a combination of manufacturers' recommendations, industry practice, and Delta's own experience; which, in turn, is based on the incidence of faults and defects for each asset design, type, make or model, and factors such as its operating environment (salt-laden atmosphere, wind, etc). Aurora continues to refine its maintenance management systems by reviewing practices and policies regularly.

Maintenance Work Types

Aurora's maintenance work comprises the following elements:

Planned Maintenance comprises of work carried out to a predetermined schedule and allocated budget. It comprises routine/preventative and corrective maintenance, inspections, refurbishment/renewals/replacement. This includes the following:

Routine and Corrective Maintenance and Inspections:

- fault rectification work that is undertaken at a time or date subsequent to any initial fault response and restoration activities
- routine inspection and condition assessment
- functional and intrusive testing of assets, plant and equipment including critical spares and equipment
- helicopter, vehicle and foot patrols, including negotiation of landowner access
- asset surveys
- environmental response
- painting of network assets
- outdoor and indoor maintenance of substations, including weed and vegetation clearance, lawn mowing and fencing
- maintenance of access tracks, including associated security structures and weed and vegetation clearance
- customer-driven maintenance
- notices issued
- vegetation management

Note that if a fault involves major refurbishment work, it may be that the faulted unit is renewed by a serviceable unit; for example, a spare transformer unit. The faulted unit can then be placed on a planned programme of work to be refurbished later, or may in-fact be disposed of if refurbishment cannot be justified.

Replacement/Renewal

This is carried out in response to the need to maintain network asset integrity for current security and/or quality of supply standards and includes expenditure to replace or renew assets incurred as a result of:

- the progressive physical deterioration of the condition of network assets or their immediate surrounds;
- the obsolescence of network assets;
- preventative replacement programmes, consistent with asset life-cycle management policies;
- the need to ensure the ongoing physical security of the network assets;

and includes replacement or refurbishment of components of an asset class (e.g. seals, bushings).

At present about 33% of total maintenance expenditure is allocated to routine and corrective maintenance and inspection, with 12% allocated to asset replacement and renewal.

Unplanned Maintenance - Unplanned maintenance is usually carried out in response to an unplanned instantaneous event or incident that impairs the normal operation of network assets (e.g. service interruptions and emergencies). It is corrective (reactive) work, either temporary or permanent, required in the immediate or short-term to restore an asset to working condition so it can continue to deliver the required service or maintain its level of security. As such, this comprises work that must be performed outside the predetermined schedule as identified through defect reports, faults and emergency situations.

Unplanned maintenance also includes operational support such as mobile generation used during an outage or emergency response, plus any necessary response to events arising in the transmission system.

Identification of unplanned maintenance can come from a variety of sources such as the general public, Delta employees, emergency services. A network service request form is used to identify and record this information; and formally report network defects.⁹

⁹ A defect is where an asset is no longer in a state or if left uncorrected will end up in state where it can no longer adequately perform its expected function.

Once a defect has been identified and reported it is logged on a defects register. A review is carried out to determine associated risk and the remedial action required, which is subsequently prioritised in a programme of planned works; however some defects may require immediate or urgent action.

Defect 'criteria' have been defined and these vary between asset types. For some, the key aspect is safety (for example - risk of explosion, fire or electrocution); for others, it is maintaining a reliable supply, while others are driven by the economic consequences of allowing components to deteriorate past the point where corrective action is desirable (for example - distribution transformer corrosion and power transformer insulation embrittlement).

Other related maintenance activities include evaluating faults to predict maintenance or renewal requirements; and service disconnections.

At present approximately 41% of total maintenance expenditure is spent on service interruptions and emergencies.

Vegetation Management

Under the Electricity (Hazard from Trees) Regulations 2003 Aurora, along with vegetation owners, is jointly responsible for protecting the security of the supply of electricity and the safety of the public by ensuring vegetation does not encroach on Aurora's electrical conductors.

Vegetation management involves felling, removing or trimming vegetation (including root management) that is in the proximity of overhead lines or cables. It includes expenditure arising from the following activities:

- inspection of affected lines and cables where the inspection is substantially or wholly directed to vegetation management (e.g., as part of a vegetation management contract). Includes pre-trim inspections as well as well as inspections of vegetation cut for the primary purpose of ensuring the work has been undertaken in an appropriate manner;
- liaison with landowners including the issue of trim/cut notices, and follow up calls on notices;
- the felling or trimming of vegetation to meet externally imposed requirements or internal policy, including operational support such as any mobile generation used during the activity.

At present approximately 13% of total maintenance expenditure is spent on vegetation management.

5.4.2 Asset Renewal Strategy and Policy

Asset Renewal Policy

Renewal or replacement of equipment is scheduled when the annual cost to own, operate and maintain existing equipment plus the average annual cost of consequential failure exceeds the annual cost to own, operate, and maintain new equipment. Replacements are also scheduled when the design or condition of equipment is a significant hazard to operating staff or the public.

Asset Renewal Strategy

Asset renewal strategy encompasses three main approaches, each of which is appropriate for the different asset categories on Aurora's network.

A risk- and condition-based replacement strategy is applied where there is a significant implication due to failure, such as major health and safety risk, significant reliability of supply consequence or a major expense in repair. This strategy is applied where ongoing condition inspections are needed to comply with regulations or where the costs of condition monitoring are small compared with the costs associated with failure.

A run-to-failure strategy is applied to assets where the consequences of failure are not major and where the costs of ongoing condition monitoring may outweigh the costs of failure.

An age and obsolescence-based replacement strategy is applied to assets with a high level of technical complexity or a high level of interconnectedness with other network assets (that is, the operation of a system as a whole is dependent on the integrity of several assets). It includes the need to replace equipment because of the availability of spares, or for standardisation or changes in technology.

5.4.3 Decommissioning Policy

A policy on Site Decommissioning for Aurora's assets has been drafted. This standard sets out the requirements for site decommission of Aurora's electrical assets to ensure public safety, avoid environmental damage and avoid property damage.

The scope of this standard covers both overhead and underground assets. Major assets and any item that represents an elevated environmental risk, risk to property damage or risk to the public have been separately identified. For assets that fall outside this criteria, the standard must still be followed.

It is proposed that decommissioning of Aurora's electrical assets follow an environmentally sustainable process that considers certain steps for removing, assessing, remarketing and recycling. It is anticipated that the policy will be finalised and adopted in 2013/14.

The following section provides detail on Aurora's key asset categories and associated strategies for each.

5.5 Lifecycle Asset Management Strategies

5.5.1 Introduction

This section describes Aurora's existing assets by category. These categories are: Subtransmission, Zone Substation, Distribution, Low Voltage and Other/Secondary. For each category, the asset and its management approach are discussed under the headings below.

Asset description

A brief description giving an idea of the type, function and location of each asset category.

Asset capacity/performance

Design capacity and utilisation with any constraints, failure modes and deterioration specific to this asset.

Asset Data & Condition

A summary of the asset's current condition including an age profile and comments on asset information
See Section 2.6 for further detail on data completeness and accuracy

Maintenance plan

The ongoing work plans required to keep the asset serviceable and prevent premature deterioration or failure. The main types of maintenance carried out on Aurora's network are outlined in the previous section.

Replacement plan

These are work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity; major renewals/replacements are covered in Section 6.

Creation/acquisition plan

This is capital work that creates a new asset or improves an existing asset beyond its existing capacity. Aurora produces development reports(DR) for major projects; these provide detailed appraisal of issues, options and recommended solutions.

Disposal plan

This is any of the activities associated with disposal of a decommissioned asset.

Standards, policies, plans and other documentation relating to the management of these assets over their life cycle are presented in Appendix D. Budgeted costs for each maintenance activity type as well as asset category is provided in Section 5.6.

5.5.2 Poles

Asset Description

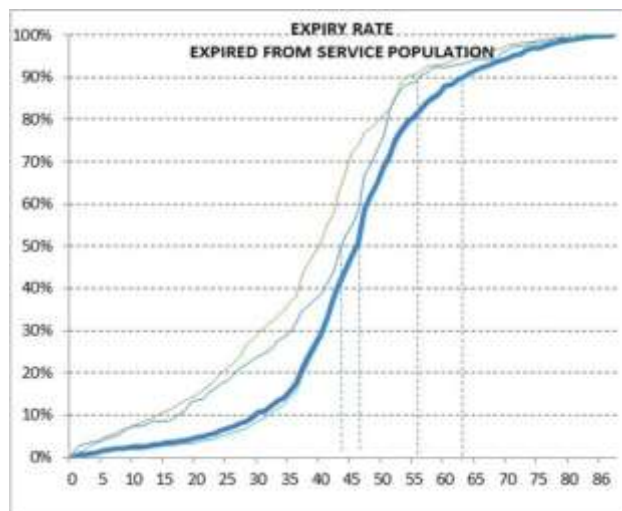
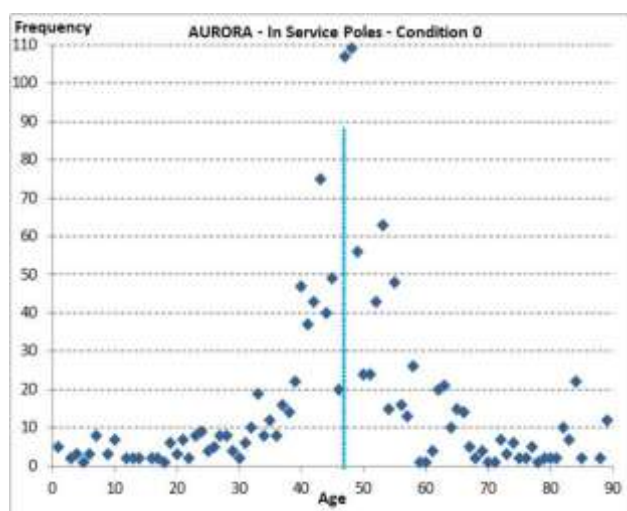
Aurora has approximately 53,760 poles, which have a material type of either concrete/steel, wood or other. These poles support subtransmission, distribution and low voltage conductors. Over 60% of Aurora's poles are wooden and approximately 37% are concrete/steel. The Dunedin network contains more concrete poles than Central (25% and 12% of the total, respectively); and both have similar quantities of wooden poles (ranging from over 15,000 to over 18,000 respectively).

Asset Capacity/Performance

From the 1990's and up until recently, softwood poles have been used as replacements for both concrete and hardwood poles, but questions arose as to their longevity in the Central Otago environment due to excessive twisting. Poles in rural areas, particularly Central, have also been subject to wear due to interference from stock where lines run through farmland (see photo).



The graph on the left below illustrates the age profile of in-service condition 0 poles (all material types) and indicates that the population is normally distributed, with most being in the 45-55 age bracket. The graph on the right illustrates the expiry rate of poles on the Aurora network.



Age

Previous AMP's have stated that in coastal areas poles tend to last over 45 years. Further detailed analysis of hardwood poles in both Dunedin and Central (across all condition ratings) has found that on average poles in

Dunedin have tended to last longer (around 60 years) compared to those in Central, which appear to be more aligned with the 45 year assumption (see graphs on following page).

Investigations into regional differences will continue in 2013/14 with the intention of informing renewal assumptions and associated expenditure programmes. Assumptions on unit costs are being reviewed and updated in preparation for the generation of revised pole renewal profiles.



Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for poles. Data currently held includes location, date installed, voltage class, material, condition, year manufactured. Figure 5.6 below shows the age profile for poles associated with distribution. Figure 5.7 presents the age profile by material type. Nearly 50% of Aurora's wooden poles are at or past their theoretical life and require replacement. (Note: EHV represents Subtransmission 66kV and 33kV; HV represents Distribution voltages of 11kV and 6.6kV; LV represents 0.4kV)

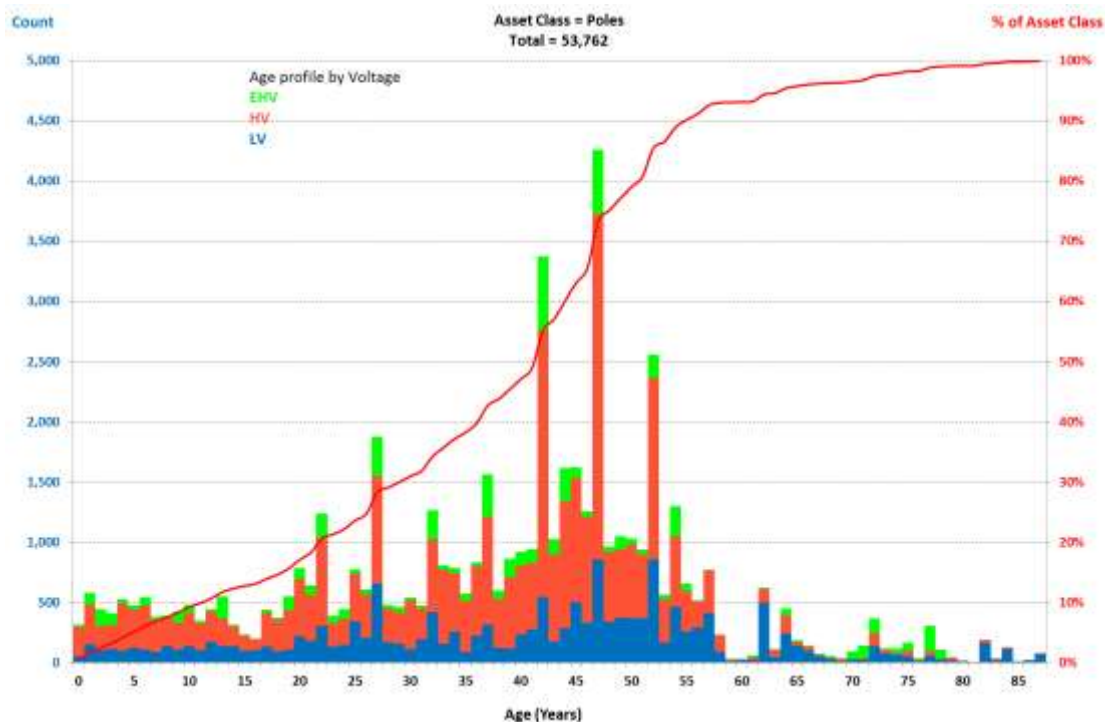


Figure 5.6 – EHV, HV and LV Poles Age Profiles

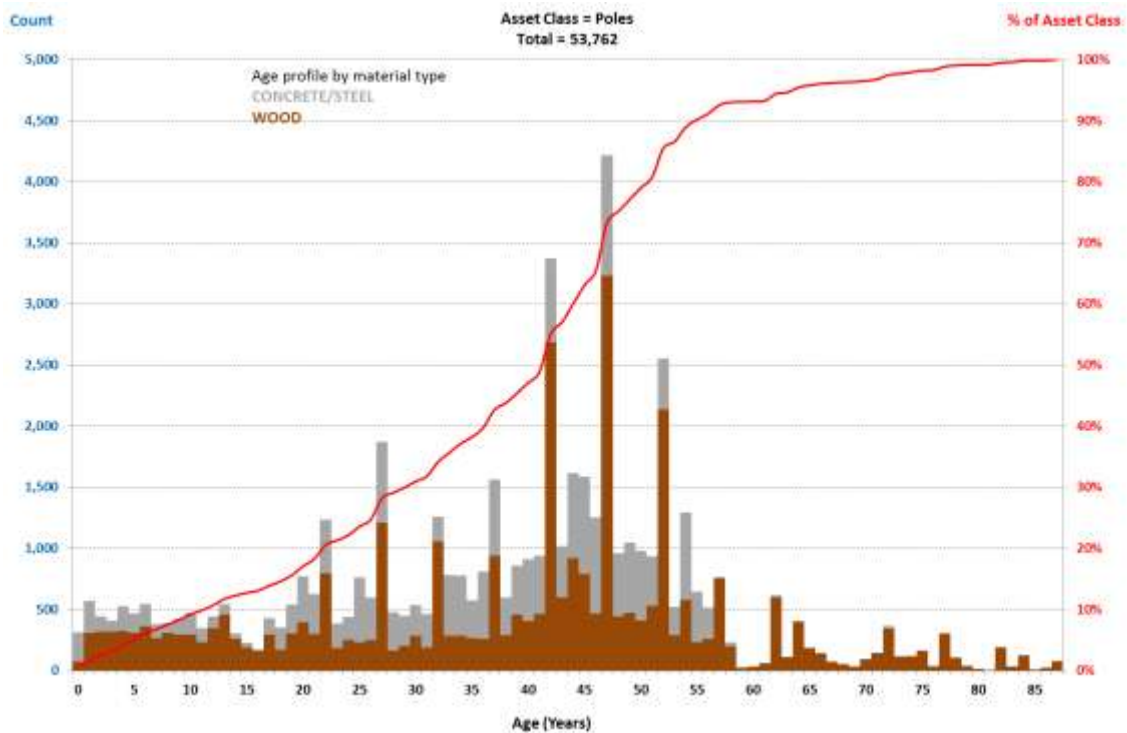
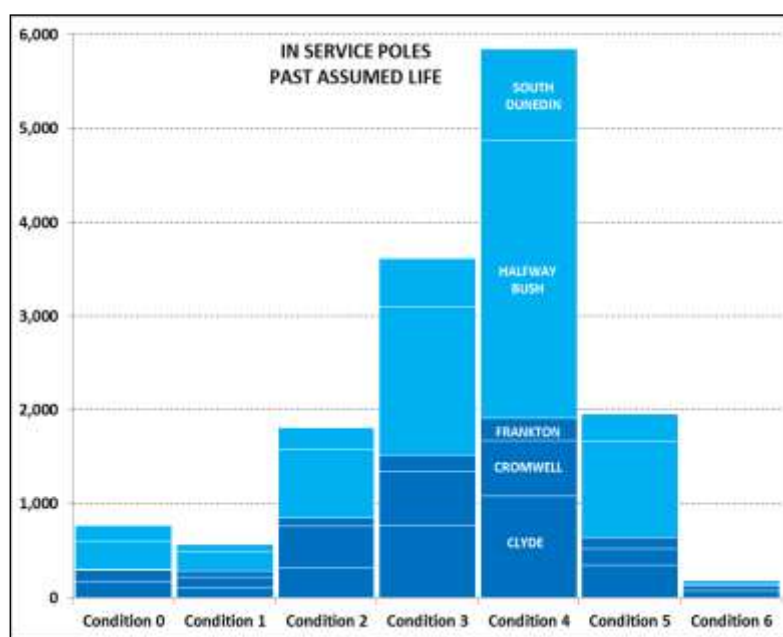


Figure 5.7 – Age profile for Wooden and Concrete poles

The number of condition 0 poles on the network is a concern for Aurora and focus is being placed on addressing this risk. Condition 0 means an overhead line structure that is at risk of failure (under certain conditions described in the (Electricity Safety) Regulations (2010) must be marked and repaired or replaced not later than 3 months after finding the risk of failure. The graph below provides an indication of the quantity of poles within each condition rating that are past their assumed life, for Dunedin and Central; sub-categorised by each GXP. It is important to mention here that pole failure through deterioration can occur within all asset condition ratings. Options for pole testing technology are currently being considered to assist in providing more objective and accurate condition assessments.



Maintenance Plan

All overhead poles are closely inspected on a regular basis, and condition assessments made and recorded, with priorities established for maintenance planning. In addition:

- Annual drive-by patrols are carried out on the larger subtransmission lines to provide a visual check on such aspects as leaning poles
- Subtransmission poles undergo detailed inspection at intervals predetermined by their last condition assessment with the interval ranging from two years for a pole that is considered to have three to five years of remaining life and ten years for a pole that is considered to have more than twenty years of remaining life.

At present, hardwood poles are being renewed at the rate of about 1.5% per year. The pole age profile implies that the renewal rate will gradually increase over the next 20 years, and then decline again.

Approximately \$0.8M per annum is allocated to pole maintenance expenditure. A further \$3M of capital (see below) has been allocated for major renewal/replacements associated with poles.

Replacement Plan

A program is underway to replace poles that are in poor condition. A holistic approach has been established that combines the pole, pole hardware and vegetation condition data to develop targeted programmes, with financial resources secured to carry out works on complete feeders for pole and pole hardware renewal in conjunction with vegetation management.

A sum of \$3 million was allocated for the 2012/13 year and a similar quantum of work is proposed for the next two years, with \$2 million per annum currently allocated from 2015/16 onwards. A review and update of pole renewal requirements will be carried out in 2013/14 in light of new assessment criteria and better data becoming available as it is likely that funding for renewal requirements for this asset category will be required to increase over the coming years.

A framework for risk assessment and prioritisation has been developed and will be rolled-out in 2013/14. This will enable better prioritisation of at-risk areas in the network so that renewals and maintenance programmes are more effective at attaining a balance between, performance, risk and cost against budget allocations.

Disposal Plan

As per proposed decommissioning policy outlined in Section 5.4.3.

5.5.3 Subtransmission

5.5.4 Subtransmission Lines (66 kV and 33 kV)

Asset Description

Subtransmission lines provide important security to Aurora's network, conveying electricity from GXP's to zone substations. A description of Aurora's subtransmission network, including capacity information, is provided in Section 5.2 and Tables 5.4-5.7.

Asset Capacity/Performance

Nearly 50% of Aurora's overhead subtransmission is over 40 years old. The number of faults has averaged approximately 5.5 per 100 km per year for subtransmission lines over the last 5 years.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission lines. Data currently held includes conductor size, age and nominal and operating voltage. Other paper-based records such as as-builts are also available. Updated data generally comes from routine inspections (as outlined in the maintenance plan in the following section) or related works.

The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses, and its maintenance history. The 33kV and 66kV lines are considered to generally be in good condition. Based on

existing loading, no significant expenditure is expected within the planning period, with the exception of the projects being driven through system growth.

The age profile of subtransmission lines (33kV and 66 kV) is shown in Figure 5.7. There are lines that are 105 years old. These are the Halfway Bush to Berwick “A” and “B” lines. The lines have solid copper conductor and the short spans have contributed to its long life.

It is currently assumed that a line located on the coastal areas near Dunedin may have a life of about 30 years, limited by salt corrosion; however, the same line located in Central will often be in excellent condition after 70 years. Generally in coastal areas, insulators will last about 30 years, conductors 40 years.

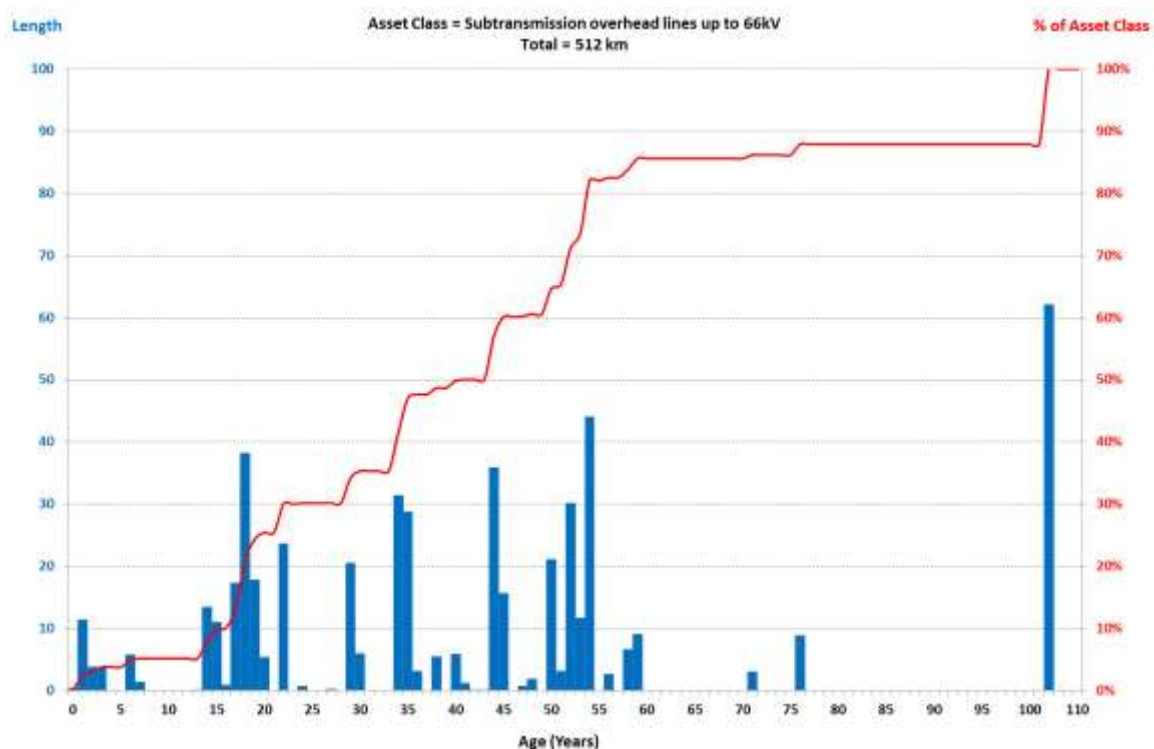


Figure 5.7 - Subtransmission Lines age profile – up to 66kv

Maintenance Plan

Along with poles, all overhead lines are inspected on a regular basis, and condition assessments made and recorded, with priorities established for maintenance planning. In addition annual drive-by patrols are carried out on the overhead 66 kV and 33 kV lines to provide a visual check on such aspects as tree growth, leaning poles, or broken insulators and so on.

Maintenance forecasts are projected using the assessed condition where the assessed condition of each major component of each line is coded against condition criteria which are used to set maintenance priorities.

Patrols are also carried out, on request, if a line trips out on earth or over current fault of unknown source.

Creation/Acquisition and Disposal Plan

For planned projects related creation/disposal of assets in this asset category see Section 6.6 – Network Development.

5.5.5 Subtransmission Cables

Asset Description

A description of Aurora's subtransmission network, including capacity information, was provided in Section 5.2. Aurora has 33kV subtransmission cables, which are mainly found on the Dunedin. Additionally there are pockets

of 66kV subtransmission cables in Central where a section of overhead line has been undergrounded through new subdivisions.

Cables are characterised by their insulation system and the types installed for Aurora's subtransmission are PILC, gas-filled, oil-filled and XLPE. XLPE are considered the most economic choice for subtransmission cables. Aurora uses single-core XLPE cables, as opposed to three-core, as this facilitates the effective application of water blocking tapes. The cable conductors are copper or aluminium.

Dunedin's central city subtransmission cable network consists of 10 pairs of 33kV transformer feeder circuits, from the Halfway Bush and South Dunedin GXP's and a tie cable between the Ward Street and Neville Street substations. The geographic layout for Dunedin is shown in Figure 5.9



Figure 5.9 – Dunedin Subtransmission 33kV cable network

Asset Capacity/Performance

In Dunedin, the PILC cables suffer from oil draining from the paper (particularly if installed on steep slopes). This phenomenon has been the cause of several faults on the Kaikorai Valley subtransmission. Gas cables have been more prone to outages that are difficult to locate, mainly due to gas leaks. In Central Otago, thermal resistivity is an issue so site specific requirements are set for new subtransmission cables.

Leaks have also been observed to occur regularly at cable joints, particularly after a shock load event. A shock load will occur when one cable of a pair trips causing the doubling of the load on the cable left in service. This increases the chance of having a complete loss of 33 kV supply to a zone substation.

The cause of leaks has also been linked to corrosion of bronze tapes due to deterioration of the cable rubber sheath, which allows moisture to enter the cable (see photos). Investigations and analysis have identified that gas cables in particular have had a high failure rate development report DR12). Historic performance indicates that over the last 20 years, there have been outages due to gas cable failures nearly every year.



Failed Bronze Tape



Degraded Rubber Sheath

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and operating voltage; other paper-based information is also available.

The age profile for all 33kv subtransmission cable types is presented in Figure 5.10; the majority were installed in the 1950's, 60's and 70's. With a theoretical useful life of 70 years, nearly 60% of Aurora's underground subtransmission is over 40 years old. In 2011 partial discharge testing of the cables in Kaikorai Valley was carried out and the results were satisfactory, however routine partial discharge testing of these cables needs to be established.

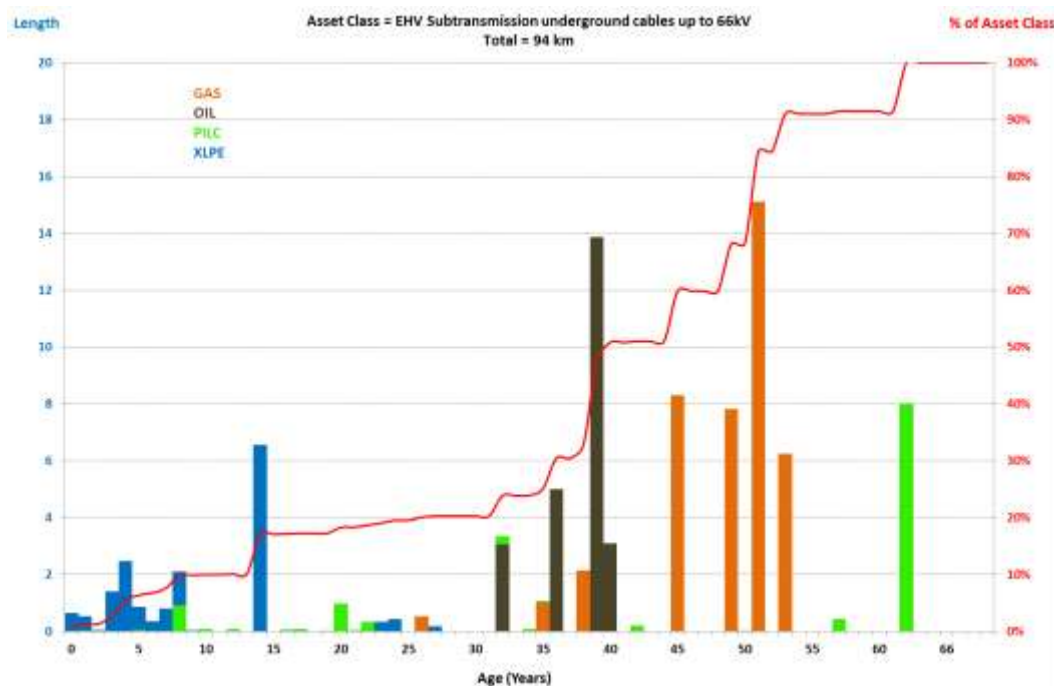


Figure 5.10 – Subtransmission Cables (33kv) age profile

Maintenance Plan

An above-ground visual inspection programme is in place, which involves inspecting the route of each cable for ground disturbance or ground movement, providing suspect areas for further detailed investigation.

Pressure gauges and alarms are installed on the gas and oil-filled cables. The gauges are read monthly and the alarms are tested at six-monthly intervals, and the outer sheath electrical integrity on most cables is tested annually.

The 33 kV underground cables do not have a planned refurbishment programme. The cables are relatively maintenance free with the exception of issues previously described. However, when a fault does occur, it is expensive to repair, being very labour intensive. For example, the average time to locate and fix a gas leak approximately 400 hours. Damaged by third parties (for example - road openings) also drive reactive maintenance needs.

With limited routine testing and maintenance carried out in the recent past, gas cables are of concern to Aurora and as such many are scheduled for replacement within the next 10 years.

Replacement Plan

The proposed timing of replacement for 33kv cables in Dunedin is highlighted in the table below. This is an initial program and performance of the cables could alter priorities. Initial cost estimates are shown in Table 6.13, with proposed costs being spread over two years due to the large scale of each project. The Andersons Bay cable replacement commenced in 2012 and is programmed to be finished in mid 2013.

GXP	Cable Name	Type	Installed	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Halfway Bush	Neville St*	Gas	1961							
	Willow bank	Gas	1963							
	Smith St	Gas	1959							
	Ward St	Gas	1967							
	Kaikorai	PILC	1950							

**Part of Neville St Substation upgrade (Project ID 2324) - it is proposed the replacement of the Neville Street 33 kV gas cables be carried out at the same time as the substation upgrade; and the connection be moved from the HWB GXP to the South Dunedin GXP.*

The rationale for the priority is as follows:

- The Neville Street and Smith Street cable upgrades are scheduled to be replaced in conjunction with the upgrade of the associated substation outlined on the following page.
- Willowbank has a moderate priority as it will be possible to fully off-load Willowbank but the cable is the unreliable bronze tape type.
- Kaikorai Valley cables have had partial discharge testing carried out and the results were satisfactory, however past performance indicates recurring issues due to cable paper drying out through oil migrated as previously described. As such, replacement is scheduled for 2018/19
- The Ward Street cable is last on the list as it is the youngest cable and has an aluminium sheath which is more reliable than the bronze tape cable.

Creation/Acquisition & Disposal Plan

Delta has recommended that the long-term configuration of Dunedin 33 kV subtransmission network retains the existing transformer feeder configuration but with the Neville Street substation supplied from the South Dunedin GXP.

5.5.6 Zone Substations

5.5.6.1 Zone Substation Buildings

Asset Description

There are 36 zone substations on the Aurora network. The majority of the buildings consist of concrete, brick, plaster materials, with a few wooden. The age of these buildings ranges from 2-70 years old, with most of the structures being established in the 1950's-1990's. Fences around the buildings also comprise of various materials including wood and metal.

Maintenance Plan

Buildings, Grounds, Fences

There is regular maintenance of zone substation buildings, grounds and fences: buildings are serviced by contract cleaning staff at fortnightly intervals. Grounds maintenance is also outsourced. Corstorphine, South City and Ward Street substations have asbestos materials installed in some areas. Tests are carried out at 5-year intervals to monitor air-borne fibres. A number of buildings will have exterior paint work carried out within the planning period.

The buildings were assessed by external consultants in 2009 and a 10-year building maintenance plan (2010-2020) was developed. This plan details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services, and the interior. This information has been incorporated into Aurora's maintenance programme and prioritised as necessary.

Replacement Plan

Buildings, Grounds, Fences

The wooden gates into the switchyard at North City substation have reached the end of their life. It is proposed they be replaced with metal gates similar to the units used for the Frankton substation upgrade.

Creation/Acquisition Plan

Several zone substations are programmed for significant upgrade of transformer and switchgear equipment within the AMP planning period. In addition, new buildings will be constructed where new substation assets are established (see Section 6 and Table 6.13).

The major substation projects are Neville Street, Roxburgh (underway) and Outram. Soil tests at the existing Neville Street site indicate the land is very vulnerable to liquefaction during an earthquake and any structures on the site should have piled foundations and investigations have identified that the most economic upgrade option is to completely rebuild the substation on land adjacent to the existing site. The site for this has been identified and is currently leased to an external party; the lease for this site ends in 2015. This new site also contains significant trees on the Dunedin City Council register and as such Aurora will liaise with the DCC regarding this issue.

In response to recommendations from the Royal Commission for changes to the building legislation, more comprehensive assessments of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out. Outputs from this will inform the revision of the building maintenance and/or upgrade programmes for 2014/15 onwards.

5.5.6.2 Zone Substation Switchgear

Asset Description

Switchgear (circuit breakers) are installed to provide safe interruption of both fault and load currents during power system faults. They are placed in the network to aid with protection of line, cable, transformer and ripple injection assets. Aurora has both outdoor and indoor 33kV switchgear.

Asset Capacity/Performance

There are 18 VVVE breakers on the network and moisture ingress has been a problem with other units. Failures have been attributed to moisture in the oil due to the failure of the bushing extension seals causing corrosion of

the aluminium extension tubes. A full investigation is underway on the condition and management of the remaining VWVE units in service on the network.

In 2012/13 switchgear at one zone substation failed and work has been carried out to replace these assets.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute information for switchgear. Data currently held on this database includes age, location, type/model. Other information available includes that collected through routine maintenance programmes, as outlined in the following section.

The age profiles for 66 and 33 kV circuit breakers and 11 kV/6.6 kV circuit breakers are shown in Figures 5.11 and 5.12 respectively. A significant proportion of the 33kV switchgear (40%) is older than 40 years which is nearing the end of its theoretical life. Around 35% of the 6.6kV and 11kV ground mounted switchgear is older than 40 years.

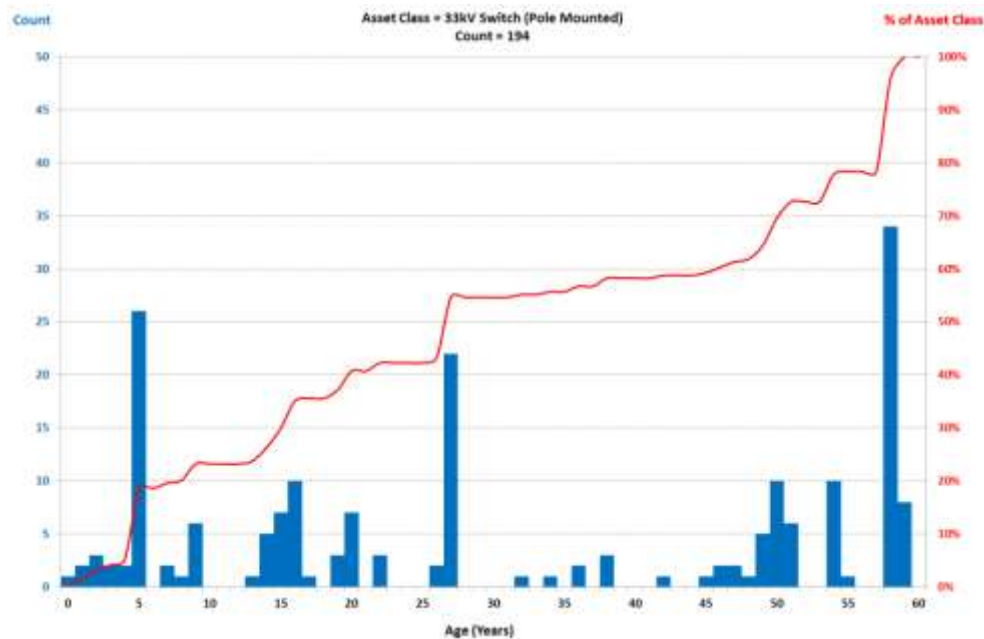


Figure 5.11 – 66 and 33 kV Zone Circuit Breakers age profile

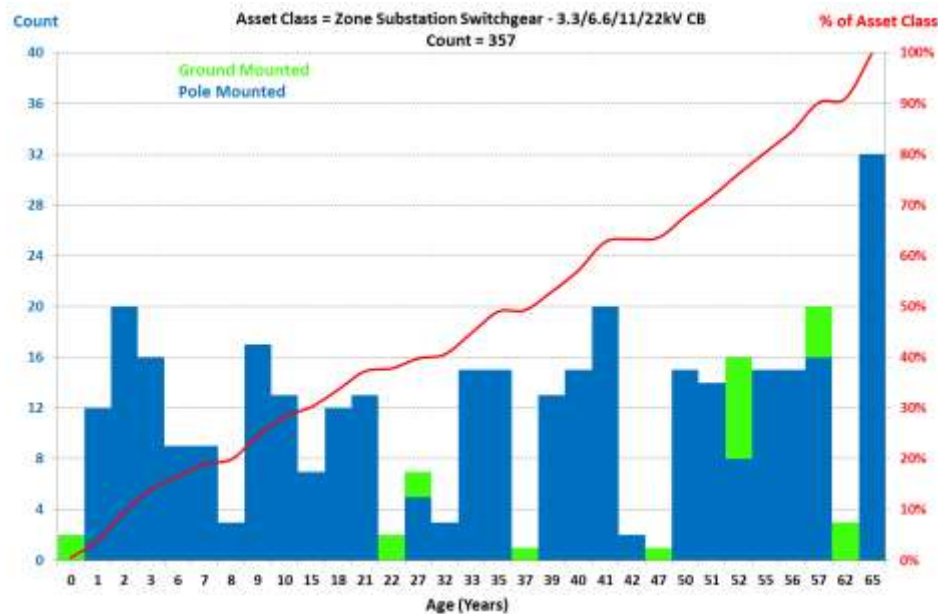


Figure 5.12 – 11 kV and 6.6 kV Circuit Breakers Age Profile

Maintenance Plan

Intervals for minor and major services (and the type of work to be carried out) are defined for each type, make and model, with the interval monitored against failure rates. These services vary from annual servicing to infrequent major overhauls, costing in the order of a few hundred dollars per breaker to several thousand dollars respectively.

Servicing expenditure for circuit breakers is determined through an analytical model, whereby individual circuit breaker servicing frequencies, together with average costs per service, enables the model to calculate the annual servicing cost based on the population of circuit breakers in each year.

Greater emphasis is being placed on in-service diagnostic testing as techniques for this become better developed. This can be a cost-effective means of identifying defects and items that are at risk of failure. It includes the use of thermographic cameras to identify "hot spots".

Specifically, maintenance includes:

Circuit Breakers - oil circuit breakers are given an overhaul at 4-year intervals or after operation under severe fault conditions.

Isolators - are checked for operation and condition in conjunction with the 4-year routine overhaul for the circuit breakers.

Painting of outdoor circuit breakers is undertaken on a rolling basis with, major repaints at 10-year intervals.

Renewals/Replacement Plan

A review of Aurora's replacement programme for switchgear is being carried out. This review builds on previous analysis undertaken for programming circuit breaker renewals, which was based on data for individual circuit breaker types, make and model, together with an assessment of the expected economic service life of each circuit breaker, and its current rating. This replacement programme is still subject to confirmation via further economic analysis, however Port Chalmers and Alexandra 33kV switchgear replacement is programmed for 2013/14.

The majority of the zone substation 6.6/11kV switchgear replacements are being done in conjunction with major substation upgrades, however the proposed timing of this package work is illustrated in the table below (see Section 6.5 for detail).

Substation	Number CBs	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Neville Street	14								
Halfway Bush	16	Monitor							
Green Island	15	Monitor							
Smith Street	15								
Earnsclough	1								
Roxburgh T1 & T2	2								
Clyde-Earns. T1 & T2	2	Monitor							
Andersons Bay	15								
Willowbank	15	Monitor							
Outram	8								
Maungawera	1								
Arrowtown T1 & T2	2								
Roxburgh feeders	2								

Zone substation 6.6/11 kV switchgear replacement

5.5.6.3 Zone Substation Transformers

Asset Description

In order to transform sub-transmission voltages (e.g. 33kV) to distribution voltages (e.g. 11kV), power transformers are installed at zone substations. These have tap changers to assist with maintaining the required delivery of voltage on the network. Most zone substations have two power transformers which have bunds to contain any oil spill and fire walls between the transformers to minimise the risk of fire spreading in the event of catastrophic failure.

Asset Capacity/Performance

The transformers are capable of operating continuously at their rated capacity or at a higher rating for shorter periods depending on the ambient air temperature.

While the 33kV and 66kV transformers have been relatively trouble free some recent failures have resulted in a review of the suite of transformers. In recent years there have been two transformer failures. A more intensive monitoring and maintenance program is being developed to mitigate the possibility of further failures.

There have been problems with slow operation of the 11 kV switchgear and the transformers which were manufactured in 1952 have a history of tap changer mechanical problems. The transformers have a nominal 31 kV voltage which forces the 11 kV to be operated higher than normal which requires non-standard distribution transformers.

Asset Condition

All transformers have had their insulating oil refurbished in the last few years, and most transformers now have less than 0.1 mg KOH/g acid level, good breakdown resistance, and low moisture content. Some transformers have higher than optimum moisture content and this is being rectified by using mobile "Trojan" plant to dry the oil out. The communications and software for the Trojan is being updated in 2013/14.

It is assumed that transformers subject to moderate loading, minimal through faults, prudent monitoring and maintenance practices should last for at least 60 years. The age profile of zone substation transformers is shown in Figure 5.13. The oldest four transformers are at the Neville St and Outram substations

Although the age profile is getting high, most of these transformers have not been heavily loaded during their life.

The seals on the older breathers at the substations have deteriorated and are scheduled for upgrade.

Asset Data

Aurora's geo-database contains the main asset attribute information for zone substation transformers. Data currently held includes location, type, installation date, manufactured date, purchase date, serial number and rating. Records on the loading on the transformers are obtained via the SCADA system and analysed regularly. Section 6 contains further detail on loads.

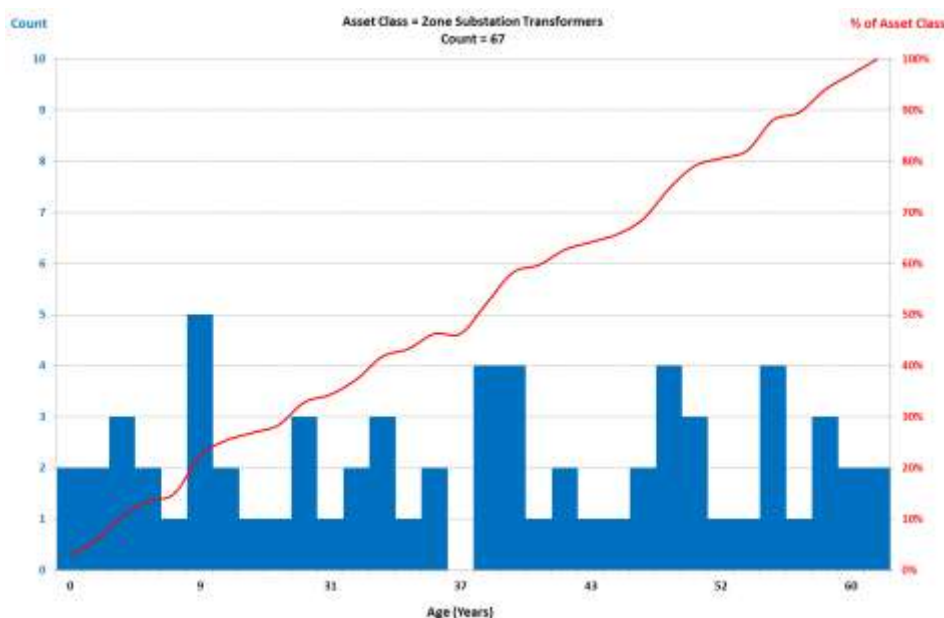


Figure 5.13 – Zone Substation Transformers 66 and 33 kV Age Profile

Maintenance Plan

Aurora is taking a prudent approach to works programming for these assets, with enhanced assessment criteria and condition based monitoring techniques being reviewed and determined. Asset criticality will be used to inform the frequency, type and level of assessment required. The outputs will be used to establish and initiate a better managed program for transformer renewal.

Similar modelling to that used for circuit breakers is utilised for assessing renewal or refurbishment of transformers. The analysis is conducted based on the total number of units in service, and an assessment of when and how many of the transformers may be removed from service for refurbishment each year. This analysis includes winding, core, and internal connection repairs, oil refurbishment, painting and radiator renewal.

Routine scheduled work on transformers and tapchangers is undertaken on a contract basis.

All transformers have their insulating oil tested annually for acid level, breakdown resistance, and moisture content. While DGA testing has been completed on an annual cycle some transformers that have been identified as requiring closer monitoring are likely to have a more frequent DGA testing regime.

Tapchangers are refurbished at intervals based on a predetermined number of operations or time interval depending on which threshold is first triggered. The usual work required is the dressing or replacement of contacts, and filtering of oil, but springs and driving mechanisms are also checked. The intervals for overhaul of tapchangers is dependent on type based on industry knowledge and historical performance.

Buchholz relay operation tests are conducted, along with tests of winding and oil temperature alarms, from source. These occur at four-year intervals, and are carried out in conjunction with associated circuit breaker maintenance. A program is underway to fit de-hydrating breathers to older transformers. A project to eliminate mercury switches from transformer Buchholz relays is underway to prevent these relays operating during earthquakes.

Painting of outdoor 33 kV transformers is undertaken on a rolling basis, with major repaints at 10-year intervals.

Replacement Plan

There is a replacement plan for breathers on older transformers to be upgraded from conventional silica gel breathers with maintenance free dehydrating made by Messko (Type MTraB). These breathers have a built-in heating unit that dries the desiccant thus eliminating the need for periodic desiccant replacement.

Major transformer replacement is occurring in conjunction with zone substation upgrade projects. Outram Zone Substation and Neville Street Zone Substation are programmed for replacement within the next 3 years. The Outram zone substation is nearing the end of its economic life. It is proposed the substation be rebuilt with one 5 MVA transformer with a parking bay for the mobile substation. Further detail on Neville Street zone substation is contained in Section 6.

Creation/Acquisition Plan and Disposal

See Section 6.6 – Network Development for further detail. Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.6.4 Other Zone Substation Equipment

Battery banks

Battery banks at substations include flooded and sealed lead acid cells with various life expectancies, several that have exceeded their nominal life of 20 years. Replacement and new banks will consist of sealed recombination lead acid cells which have low maintenance requirements, lower initial cost, and a 10 year rated life. A replacement program is underway.

Earthing

Portable earthing equipment is kept at all zone substations and is maintained to a high standard to ensure safety of maintenance personnel. Only routine maintenance is necessary.

5.5.7 Distribution

5.5.8 Distribution Lines (11kV and 6.6kV)

Aurora's overhead distribution system consists of 2335km of HV lines, taking supply from zone substations as 'feeders' which form a network to supply distribution transformers (including SWER) totalling approximately 40% of Aurora's total network. Of this, 70% of overhead HV line is located on the Central network and 30% on the Dunedin network.

Within Aurora's distribution network there are in the order of 5,000 potheads (mixture of high voltage and low voltage). Analysis to date indicates that in the order of 10% of the potheads are cast iron, although this is currently being reviewed and validated. Failure of these pose significant health and safety risk to both public and staff and a thorough assessment of these has commenced with the intention to develop a prioritised renewal programme. In the interim operational methods have been issue to mitigate the potential hazard of staff working in close proximity of cast iron potheads.

Asset Performance

Section 3 outlined that Aurora's 2011/12 performance results for overhead line faults were slightly above target and that there appeared to be a slight increasing trend. It is currently assumed that a line located on the coastal areas near Dunedin may have a life of about 30 years, limited by salt corrosion; however, the same line type located in Central will often be in excellent condition after 70 years. Generally in coastal areas, insulators will last about 30 years, conductors 40 years.

Asset Condition and Data

Aurora's geo-database contains the main asset attribute information for distribution lines. Data currently held on this database includes conductor size, length, age and nominal and operating voltage. Other information available includes that collected through construction and routine maintenance programmes outlined in the following section. Figure 5.14 details the age profile of HV lines by conductor age and pole age. Approximately 40% of conductor is aged more than 45 years.

Maintenance Plan

A rolling inspection of approximately 600 km of overhead lines occurs each year (covering LV, HV, and combinations of both), to establish priorities for the maintenance programme; and the procedures in the Electricity (Hazards from Trees) Regulations 2003 are followed.

A complete survey of the overhead network was completed in 2011. This assessed the impact of vegetation with the data recorded in Aurora's GIS. This information has been used to develop a programme of works targeting specific feeders on an annual basis, which combines vegetation, pole inspection and performance (reliability) information. It is expected that maintenance expenditure on HV lines will rise over the planning period, being predominantly driven through pole replacement needs and vegetation management as opposed to conductor replacement (also see Section 5.5.2).

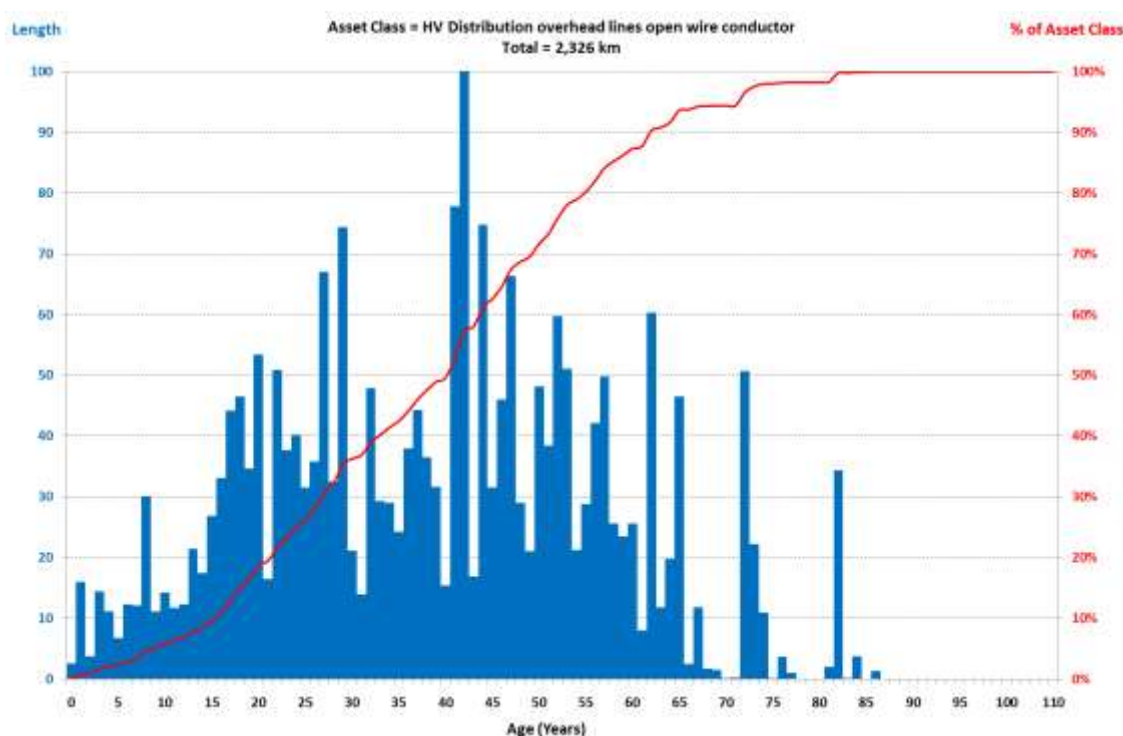


Figure 5.14 – Distribution Lines (11 kV and 6.6 kV) Age Profile

Replacement Plan

At present there is no HV conductor and cross-arm renewal programme, in both the Dunedin and Central areas. The sufficiency of this will be reviewed in 2013/14 as Aurora further develops its targeted feeder replacement programme for pole and pole hardware renewal in conjunction with vegetation management permitted under the Electricity (Hazards from Trees) Regulations 2003.

Creation/Acquisition and Disposal Plan

For planned projects related the creation of assets in this asset category see Section 6.6 – Network Development. Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.9 Distribution Cables (11kv and 6.6kV)

Asset Description

Aurora's underground cable distribution system is 904km of circuits totalling approximately 15% of Aurora's total network (including a submarine cable). Of this, 47% is PILC and 53% XLPE/PVC. HV cable insulation in the Dunedin area is predominately PILC with some XLPE. For many years, all new cable has been rated for 11kV operations even when it operates at 6.6kV.

Asset Capacity/Performance

Deterioration of HV distribution cable has not been a particular problem to date, apart from several kilometres of aluminium sheath paper insulated cable installed in 1954, where sections of this cable have been replaced as the need arose due to corrosion of the aluminium sheath. Most repairs are due to either faults at joints or terminations, or due to third party damage. In recent years there have been failures of paper lead cables at bridge abutments believed to be caused by bridge movement when heavy vehicles cross the bridge. There is also a submarine cable across the harbour that has been trouble free since the early 1990's.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute data for subtransmission cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and operating voltage; other paper-based information is also available. The age profile of HV cables is shown in Figure 5.15.

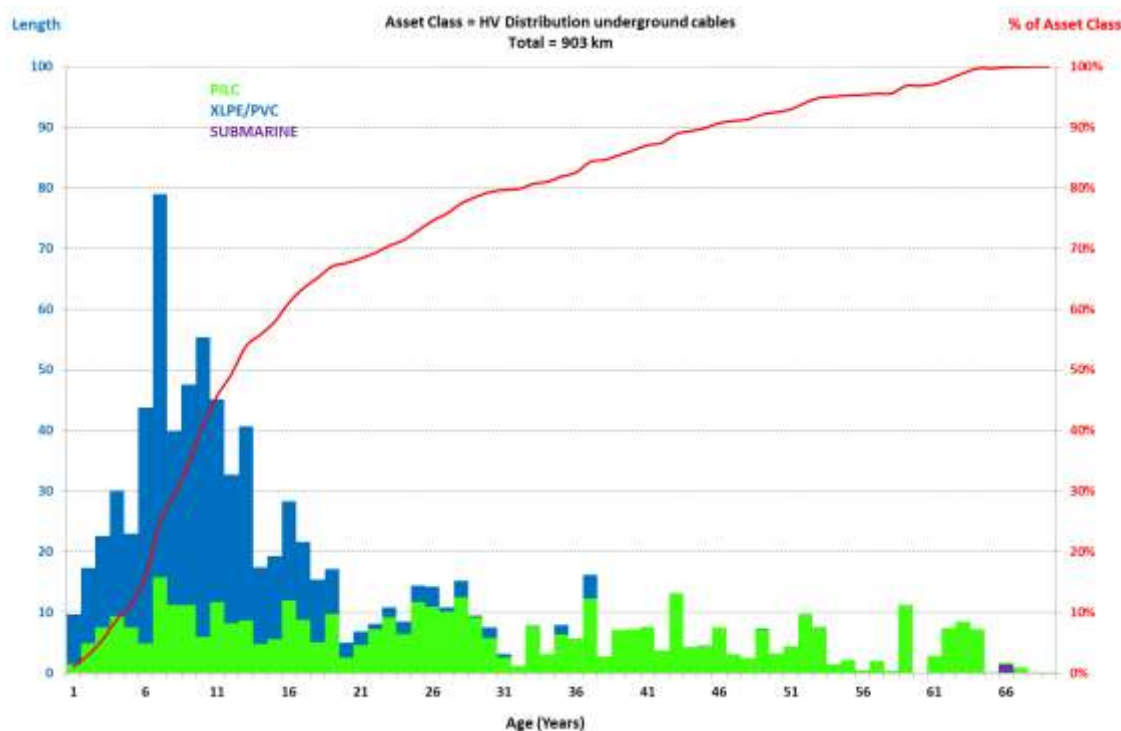


Figure 5.15 - Distribution Cables (11 and 6.6 kV) Age Profile

Maintenance Plan

No routine inspections of cables or associated equipment are made.

General distribution system earths are tested at six-yearly intervals; however earths on the single wire earth return systems are inspected at three-yearly intervals.

Replacement Plan

There is currently no programmed replacement expenditure allocated to this asset category.

Creation/Acquisition and Disposal Plan

Additional cables are installed in response to overhead to underground conversions (driven by Local Authorities) or are developer-driven as a result of new connections and subdivisions; or through other growth or upgrade plans (see Section 6.6 – Network Development). No plans to dispose of this asset other than minor disposal associated with changes and rearrangements in the network.

5.5.10 Distribution Switchgear

Asset Description

Switchgear is the combination of switches, fuses or circuit breakers. Aurora has various classes of switchgear including ground-mounted, pole-mounted, reclosers and sectionalisers and those which are associated with RMU's; located both indoor and outdoor. Together, these assets help to provide protection for primary equipment on the distribution network and assist with network reliability. A circuit breaker is the primary component that interrupts faults and there are four main types: oil, gas (SF6), vacuum and air. The main type of switchgear on currently Aurora's distribution network is oil, however this switchgear is being discontinued by its suppliers and Aurora is considering other options, which looks likely to be SF6 switchgear.

Asset Capacity/Performance

Switchgear associated with ring-main units has been relatively maintenance free, and checks on oil levels and general condition are included in the substation inspection round. However, given the associated age profile of some oil-based switchgear, focus will be given to this asset category for determining revised maintenance and renewals needs.

Fuse switch

Within the central network there are particular fuses that have limited fault rating. These are found on distribution pole top substations and are glass tube "Pacific" fuses, which are being progressively replaced as part of Aurora's expenditure programme.

Within Dunedin's CBD (including South Dunedin), Andelect fuse boxes were installed in the 1950's and 1960's when these areas were converted from overhead to underground distribution. See Figure 5.20 for a typical example. Many of these boxes are installed on consumers' premises and can be down alleyways, inside buildings or mounted high on external walls. It can be difficult to gain access to the boxes and spare parts for them are no longer available



Figure 5.20 – Typical Andelect box

Reclosers

Aurora has two KF and 8 KFE reclosers installed in the field. These reclosers cannot be operated remotely and it is not economic to convert them for remote control. The ability to remotely control reclosers can speed up fault location and/or reduce man power requirements during permanent faults downstream of reclosers.

Also, a number of distribution substations have oil circuit breakers. The Reyrolle Type C switchgear on Aurora's network is now over 60 years old, obsolete and expensive to maintain.

Asset Data and Condition

Aurora's geo-database contains the main asset attribute information for switchgear. Data currently held on this database includes age, location, type/model. Other information available includes that collected through routine maintenance programmes outlined in the following section.

Many switches and fuses were installed in the 1940's-1990's and many are therefore near to or past their theoretical useful life (of around 35-40 years) and require replacement. The age profiles for ground and pole mounted plus ring main distribution switchgear is shown in Figure 5.16.

Note that due to the age profile of oil switchgear, the maintenance procedures and intervals are being reviewed and benchmarked against industry peers and manufactures recommendations to ensure a robust and consistent regime is followed. From this, an updated maintenance plan will be established. Risk and condition assessments are underway in order to better understand current state of these assets and to help further prioritise maintenance spend.

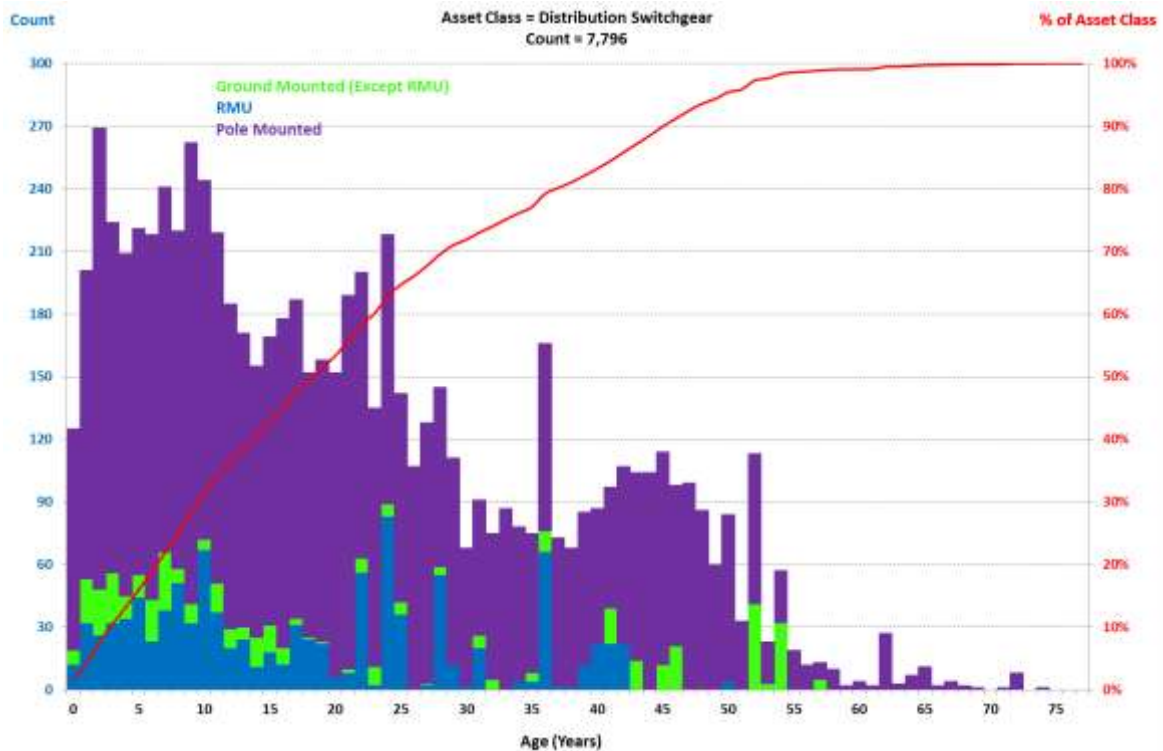


Figure 5.16 – HV Switchgear Age Profile

Maintenance Plan

Inspection expenditure for this asset category is presented in Section 5.6.

For each type, make and model of circuit breaker, intervals for minor and major services, and the type of work to be carried out is defined, with the interval monitored against failure rates. These services are infrequent major overhauls, costing up to several thousand dollars.

Checks on oil levels and general condition for ring-main switchgear are included in the monthly substation inspection round.

Greater emphasis is now also being placed on in-service diagnostic testing, as techniques for this become better developed. This can be a cost-effective means of identifying defects and items that are at risk of failure. It includes (for example) chemical analysis of transformer oil, and use of thermographic cameras to identify "hot spots".

Replacement Plan

Aurora's budgeted maintenance expenditure for renewals and replacement costs are shown in Section 5.6; capital expenditure is presented in Section 6.7. Provision has been made for replacement of some oil-based switchgear on an annual basis.

Note that the HV oil circuit breakers installed in some substations supply critical circuits and are reaching the end of their physical life. These will be renewed within the planning period, and expenditure on these will gradually reduce over the duration of the planning period.

The Reyrolle Type C switchgear is proposed to be replaced within the planning period and Pacific fuses are also being progressively replaced over the next 10 years.

A budget of \$36,000 per year over the next 10 years has been set for the replacement of Andelect fuse boxes based on an average estimated cost of \$6000 each. It is present policy for Aurora to fund the removal of these boxes and the re-establishment of the connection point in a ground mounted pillar box on the property boundary if the consumer mains are being upgraded.

Creation/Acquisition & Disposal Plan

For planned projects related creation/disposal of assets in this asset category see Section 6.6 – Network Development.

5.5.11 Distribution Transformers

Asset Description

Distribution transformers are installed on our network to transform voltage to a suitable level for customer connections. The main types of distribution transformers on Auroras network are pole and ground mounted as well as voltage regulators (of which there are 24). There are over 4200 ground mounted transformers and over 2400 pole mounted transformers. Auto-transformers are used in some parts of the network to also enable the interconnection of 11 kV and 6.6 kV sections.

The types of ground-mounted distribution transformers include.

- **Cable Box/Cable Box (standard)** - this configuration is generally used when the transformer is dedicated to one consumer, with the consumer's LV mains directly connected to the LV terminals of the transformer.
- **Package** - this configuration consists of a specially configured transformer accommodated in a fibreglass enclosure, with associated HV switchgear and LV distribution board. This configuration is no longer used for new substations.
- **Mini (standard)** - these substations are proprietary units that include an LV distribution board and can include HV switchgear. They range in size from 100 to 1000 kVA.
- **Micro (standard)** - these substations are used for low visibility. They range in size from 15 to 100 kVA, have limited space for LV distribution facilities and do not accommodate any HV protection.
- **Underground** - these substations are only used in the Dunedin CBD area and consist of an underground vault that contains a transformer and associated HV and LV switchgear. They were constructed in the 1960s and 1970s, generally have a 1000 kVA capacity, and are not a modern standard option.
- **Cubicle** - these substations consist of a standard, pole mounting, bushing/bushing transformer, mounted on the ground with cable connections to the bushings and fitted with a metal cover. They range in size from 15 to 50 kVA. This configuration is no longer used for new substations.

Asset Capacity/Performance

Pole mounted transformers range in size from 5 to 400 kVA. Transformers up to 100 kVA are accommodated on a single pole but larger sizes require a two pole support structure. Ground mounted transformers range in size from 15 to 1000 kVA.

Transformer utilisation is measured as the ratio of maximum demand in kVA to installed rating. Total system demand to total distribution transformer capacity gives an indication of overall distribution transformer capacity. For the 2012 year, this was 817MVA for the Aurora network, which was 2MVA more than the previous year.

Asset Condition and Data

Data currently held in Aurora's information systems for this asset category includes: location, type, age, maintenance history, test results, inspections. For transformers and regulators updated condition and performance data comes from routine or reactive inspections.

Figure 5.17 details the age profile of in-service Aurora-owned distribution transformers. Approximately 34% of the pole mounted transformer population is past the theoretical asset life of 45 years, with several being installed before 1940. An investigation into pole-mounted transformer structure clearance requirements is being carried out in 2013/14 to ascertain compliance status with respect to legislation. Where anomalies are identified, further investigation to identify appropriate solutions may be required.

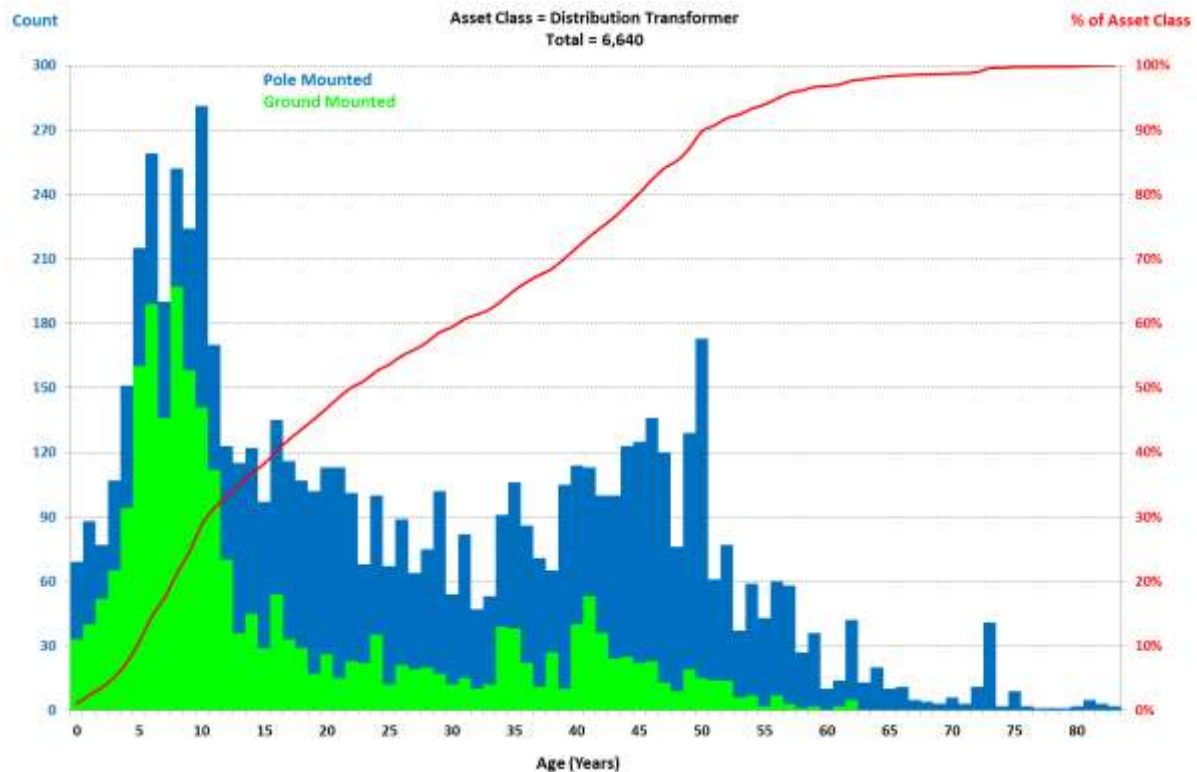


Figure 5.17 - Distribution Transformers Age Profile

Maintenance Plan

Aurora's budgeted maintenance costs are provided in Section 5.6

Similar modelling to that used for circuit breakers is utilised for assessing renewal or refurbishment of transformers. Where proactive refurbishment is required, the analysis has been conducted based on the total number of units in service, and an assessment of when and how many of the transformers may be removed from service for refurbishment each year. This analysis includes winding, core, and internal connection repairs, oil refurbishment, painting and radiator renewal.

Replacement Plan

Aurora's budgeted maintenance replacement costs are provided in Section 5.6; and capital replacement costs are presented in Section 6.7.

Distribution Transformers

Provision has been made to replace distribution transformers that are damaged or deteriorated such that they are uneconomic to repair. A budget of \$120,000 per year has been established for this.

Voltage Regulators

The 6.6kV voltage regulator at Otakou on the PC3 feeder is an old Ferranti moving coil unit manufactured in 1947 and is programmed to be replaced in 2013/14 at a cost of \$100,000. An alternative solution is to convert the supply beyond Otakou to 11kV which may eliminate the need for a regulator. Further investigation is required to determine the most appropriate solution.

Creation/Acquisition and Disposal Plan

For planned projects related to the creation of assets in this asset category see Section 6.6 – Network Development. Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.12 Distribution Substations

Distribution substations comprise the transformer (sub-categorised in the previous section), transformer pad, HV and LV fusing, and an earth mat. The main types of distribution substations on Auroras network are pole mounted, ground mounted and underground. In addition, many distribution substations are housed in structures that also require maintaining.

Asset Capacity/Performance

Dunedin

A significant rainfall event in Dunedin in February 2005 lead to five underground distribution substations flooding. During this event these had to be off-loaded, with the subsequent failure of one transformer after the event.

Central

In the Central area, many distribution pole top substations are fused with glass tube “Pacific” fuses. These fuses have limited fault rating and are undergoing replacement as outlined in previous sections.

There are approximately 65 distribution substations in the Central Otago network which had pilot wire control circuits installed between 1970 and 1988. These have been suffering from decreased reliability, and it has been standard practice, after failure of these circuits, for the retailer to renew the pilot wire relay on the consumer’s switchboard with a modern ripple receiver. This pilot wire system, controlled by interfacing Decabit relays installed at distribution substations, supplies approximately 2,000 consumers. Refer to Section 5.5.18 for further detail.

Asset Data and Condition

Data currently held in our information systems for this asset group includes: location, type, age, maintenance history, test results, inspections.

Ground Mounted Substations

In Central, there are some ground mounted substations that consist of BU-BU or CB-BU transformers in a Central Electric designed enclosure. Some of these substations are a hazard due to HV terminals being accessible behind ventilation mesh and there are also safety issues with the LV distribution boards. A programme to replace these is being rolled out.

Two-pole substations are also of concern to Aurora and a programme to replace these is also being rolled out.

Maintenance Plan

Aurora’s budgeted maintenance costs are provided in Section 5.6

Depending on the level of maintenance required, refurbishment may occur within the year (for minor items), placed on the maintenance programme or may require further assessment to determine the level of intervention required.

All ground mounted substations are inspected at three yearly intervals. Those that have HV circuit breaker equipment installed, have their tripping batteries checked three monthly and, where applicable, alarms are tested six monthly. Some ground-mounted substations have HV circuit breaker equipment installed, which helps Aurora to reduce the consequence of tripping.

Distribution substation buildings (75) are inspected at six-monthly intervals for safety, security, and miscellaneous repairs.

Substations identified as requiring refurbishment during the annual inspection will be refurbished as required.

Buildings and grounds identified as requiring refurbishment during the six monthly inspections will be refurbished as required.

Replacement Plan

Aurora's budgeted maintenance replacement costs are provided in Section 5.6; and capital replacement costs are presented in Section 6.7.

Underground substations

A programme is underway to seal and mechanically ventilate underground substations vulnerable to surface flooding or replace them with ground mounted substations if practicable.

"Two Pole" Substations

When the poles supporting "two pole" substations become unsafe, the substation is re-established on the ground when practical. An allowance has been made to replace three substations a year from 2010 to 2019 at an estimated Cost \$250,000 per year

Creation/Acquisition Plan

The Network Development section of this AMP (Section 6) contains projects relating to the establishment of new or upgraded assets on the network.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.13 Low Voltage (0.4 kV)

Aurora has a total of 1863km of LV circuit (overhead and underground) and 1269km street-lighting circuit (overhead and underground). The following sections cover low voltage lines, cables, street lighting and connections.

5.5.14 LV Lines

Asset Description

Aurora has 1037 km of LV line (55% of total circuit length). LV distribution is via radial feeders. In central business districts, LV intertie capability is provided by link boxes. In urban residential areas, there is limited LV intertie capability.

There are two types of LV overhead on the network, being predominantly open wire with only a few kilometres of Aerial Bundled Cable (ABC).

Central area has a greater proportion of underground LV compared to Dunedin is due to the growth experienced in Central since it became mandatory to underground in new subdivisions. Although growth has slowed in the recent past, it is still continuing at a higher rate when compared to Dunedin which is steadily reducing the relative proportion of overhead LV.

Asset Capacity/Performance

While significant renewal of conductor might become necessary beyond the current planning period (i.e. when the lines installed from 1965 approach 50 years of age) no significant condition based expenditure increase is expected in the current planning period.

Asset Condition

Figure 5.18 shows the age profiles for LV lines, cables and street-lighting. Approximately 40% of LV conductor is over 40 years.

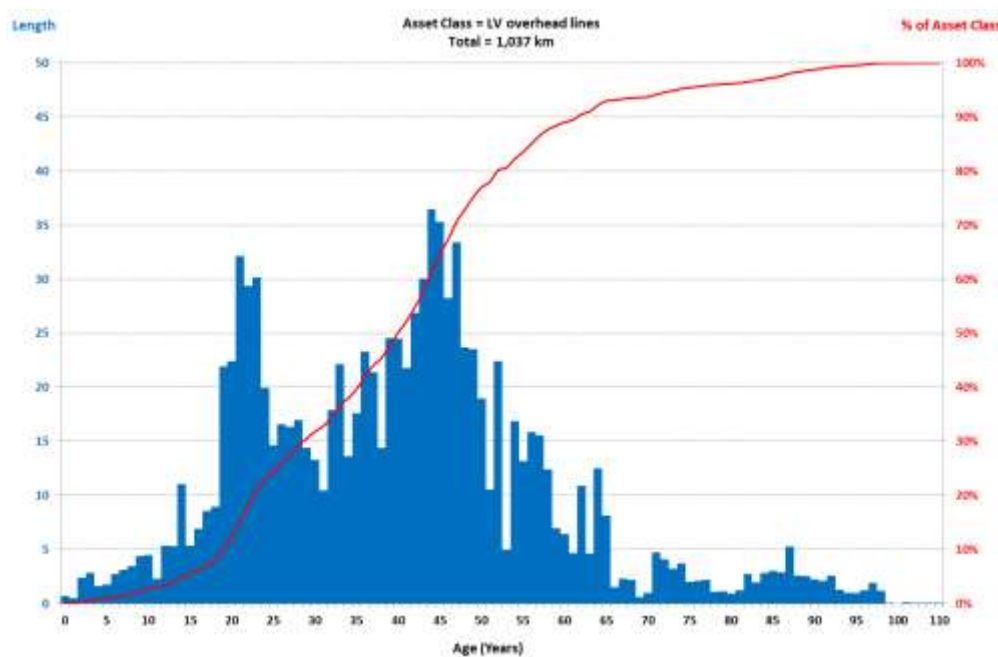


Figure 5.18 – LV Distribution Lines Age Profiles

Asset Data

Data currently held in Aurora's geo-database for this asset category includes: location, conductor type, size and age; and information collected via network inspection rounds.

Maintenance Plan

Maintenance activity is generally aligned with the pole inspections where observations are made on a routine basis as the network undergoes inspection rounds.

Replacement Plan

As well as condition based renewal work, renewal is frequently necessary due to the installation of new substations and/or local load growth and voltage complaints.

Creation/Acquisition Plan

Construction of low voltage distribution lines are generally in response to customer connection requirements only (see Section 6.6.10)

Disposal Plan

Aurora disposes of overhead lines to meet customer requirements or where other drivers may exist, such as underground conversion projects required by territorial local authorities.

5.5.15 LV Cables

Asset Description

Aurora has 825 km of LV cable. Most LV cable is cross-linked polyethylene (XLPE). However, in the Dunedin CBD, paper-insulated lead covered (PILC) cable is present.

Asset Capacity/Performance

The performance of LV cables is generally good; the majority of failures are due to damage from third party installation or some other disturbance as opposed to asset deterioration.

Asset Condition

The oldest LV cables have not indicated any significant signs of reaching the end of their economic lives.

See Figure 5.19 for age profiles of LV cables

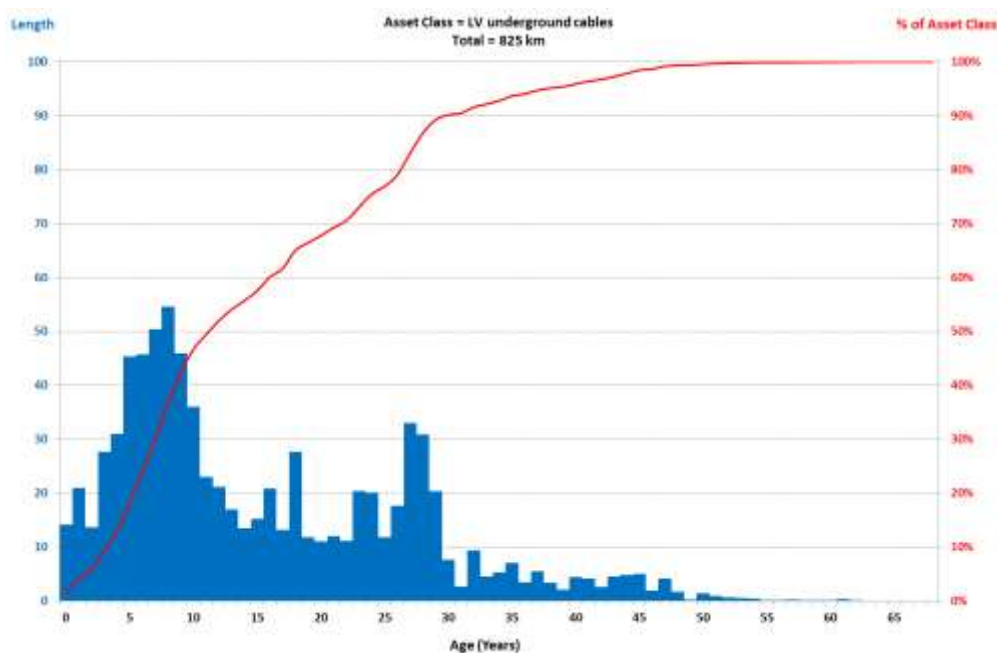


Figure 5.19 – LV Distribution Cables Age Profile

Link boxes in Dunedin and Central are of concern to Aurora and further assessment of these is required to further develop the replacement plan discussed below. In central, obsolete link pillars are driving the replacement programme.

Asset Data

Aurora's geo-database contains the main asset attribute data for LV cables. Data currently held includes location, insulation type, date installed, conductor size, age and nominal and operating voltage.

Maintenance Plan

Five-yearly inspections of underground 400 Amp LV link boxes in the Dunedin central business district are carried out. There is currently no programmed maintenance replacement expenditure allocated to this asset category as capital replacement plans are being rolled out as described below.

Replacement Plan

Over recent years, many obsolete link pillars have been renewed with modern units that provide a safer and more flexible system. This has taken place on the LV distribution system in the Queenstown, Alexandra Wanaka and Cromwell. Queenstown CBD is complete with Alexandra CBD ongoing. This work has now been extended to the Wanaka and Cromwell areas.

Underground Link Box Replacements

In Dunedin, there are 246 underground LV link boxes. Some of these boxes require replacement due to ageing and overloading; the latter of which is predominantly attributed to protection issues. It is proposed to replace three boxes per year for the duration of the planning period at a cost of \$150,000 per year

Creation/Acquisition and Disposal Plan

No plans to dispose of this asset other than minor disposal associated with changes and rearrangements in the network.

5.5.16 LV Street-lighting

Aurora has 269km street-lighting circuit (overhead and underground). Figure 5.20 shows the age profile for street-lighting. 73% of the street-lighting circuit was installed between 1940 - 2000 and 16% are over 40 years old.

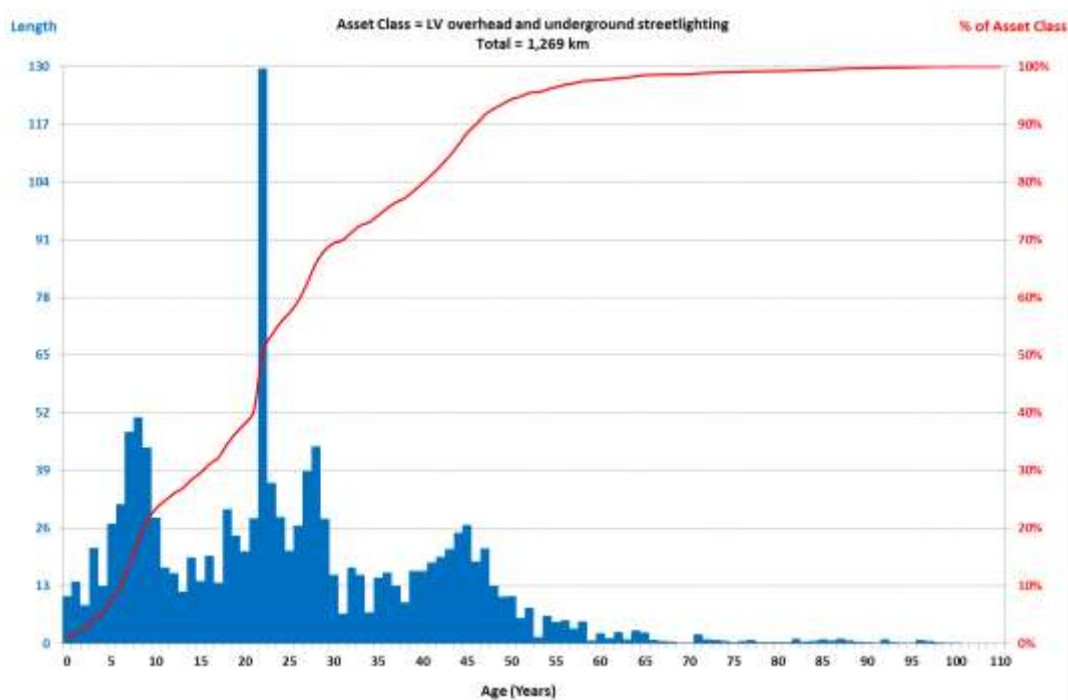


Figure 5.20 – Street-lighting (lines and cables) age profile

5.5.17 Connections

See and Section 5.6 for Aurora's maintenance and replacement expenditure forecasts and Section 6.6.10 for further comments

5.5.18 Other Network Assets (Secondary Assets)

Aurora's secondary assets comprise of equipment that provides: monitoring, control, communication, protection and automation functions. For Aurora, most of these assets are running 24/7 and are used extensively for network operation, safety control, equipment protection and asset management decision making. They are fundamental to the control and operational capabilities of the network.

Aurora's existing operating systems, SCADA hardware and load control systems were installed between 12-25 years ago and most are facing technological obsolescence with limited ability for use and operation with more modern protocols and systems.

As such, Aurora commenced a comprehensive review of its SCADA, control, communication and protection systems (SCCP) in 2011/12. From this, a number of options and solutions were identified. These were assessed further in 2012/13 in order to verify the scope, feasibility and economics for the options and solutions being proposed. Seven projects make up the proposed programme for Aurora's SCCP systems; these are outlined in Table 5.10. Maintenance expenditure is shown in Section 5.6. The text that follows provides further detail on Aurora's communications, SCADA, protection and load management systems.

Table 5.10 - Proposed SCCP projects

Revised Budget							
SCCP Project	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
SCCP P1 (Part A) - New System Control room	0	350	200	0	0	0	0
SCCP P1 (Part B) - Future SCADA master station operating system upgrade	100	100	100	2700	2000	350	0
SCCP P2 - DUD, Central and DUD - Central Comms Upgrade	553	830	170	170	0	0	0
SCCP P3 - Central Load Control System Upgrade	80	0	0	0	0	0	0
SCCP P4 - Upgrade Dunedin SCADA RTUs	385	385	364	238	378	105	126
SCCP P5 - Upgrade Central SCADA RTU's	0	200	495	350	0	0	0
SCCP P6 - Dunedin Subtransmission network protection system upgrade	380	860	320	0	180	0	0
SCCP P7 - Aurora ICCP System	220	120	0	0	0	0	0
Grand Total	1,718	2,845	1,649	3,458	2,558	455	126

5.5.18.1 Communication

Communication systems are integral to the remote indication and control of network equipment and enable communications between office-based operations with staff/contractors in the field. Communications are via a number of repeater sites located on various hilltops. Aurora also has a series of lease or rental agreements for its multiple radio sites. A number of these are pending review and renewal.

Asset Description

Dunedin

The existing communications system in the Dunedin area consists of a mixture of copper pilots, fibre optic cables, and UHF radio. A pilot cable network, installed with 33 kV cables, provides communication with twelve of the eighteen zone substations. The SCADA communications in Dunedin are also mostly via copper pilots using the Conitel protocol. However the SCADA to Mosgiel, East Taieri, Outram and Berwick Substations is via a UHF radio repeater (see Section 5.6.18.2 for further detail on SCADA).

Central

The existing Central Otago communications systems are predominately via VHF and UHF due to the large distances involved. The only existing fibre optic circuits are for short communications links.

Maintenance Plan

UHF and VHF Systems - At twelve-monthly intervals, all sites are visited; operational levels are checked, recorded and adjusted, if necessary. All aerials and power supplies, along with site security and accessibility, are also checked and rectified as necessary.

At four-yearly intervals, a more detailed inspection of aerials and equipment is undertaken, and major operational adjustments made if necessary. Central zone substation remote alarms are self diagnostic with monitoring setup accordingly.

No UHF or VHF systems have been identified as requiring renewal or refurbishment, however any significant upgrades form part of the SCCP programme.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.18.2 SCADA

Aurora has two SCADA systems; a Foxboro system, dating from 1998, for the control of the Dunedin area, and a Lester Abbey system dating from 2000, for the control of the Central network.

Dunedin

A total of 23 Remote Terminal Units (RTUs) have been installed in Dunedin substations and most of these units were installed in 1987 when the SCADA system was first introduced in the Dunedin network.

In each substation, the SCADA RTU is connected to field devices such as switches, PLCs, IEDs (Intelligent Electronic Devices), protection relays. All the aggregated information from the field devices is sent between the master station and the RTU for supervision and control. Most of the RTUs communicate to the master station in Conitel protocol.

The existing RTUs have been very reliable but face technological obsolescence due to their inability to use modern master station communication protocols and communicate with IEDs such as protection relays.

Central

The existing Central network consists of 64 RTUs for substations and remote devices like auto-reclosers and voltage regulators. All RTUs are Abbey RTUs. Communications between the Central RTUs and the Cromwell Master Station are in Abbey HDLC protocol via radio links. The existing RTUs have been very reliable but the Abbey communication protocol is only supported by the Abbey SCADA operating system.

Maintenance Plan

Current routine and preventative maintenance includes:

12-monthly checks - at twelve-monthly intervals, all SCADA transmit and receive levels are checked, recorded, and adjusted if necessary, and power supplies are checked at the master station and all remote terminals.

4-yearly tests - all alarms are tested at four-yearly-intervals, from the local alarm panel and from source, and confirmed at System Control on the SCADA screen, and by print-out. The work is carried out in conjunction with minor circuit breaker servicing work.

A service contract for the maintenance of the SCADA software commenced in July 2005, which covers a helpdesk service for faults and future software upgrades

Any revised future maintenance requirements for SCADA assets will be clarified as the SCCP programme develops.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.18.3 Protection

Protection systems are established in order to protect the electrical network in the event of power system faults. Aurora's protection comprises of: voltage transformers (VT) current transformers (CT) and protection relays. These are predominantly used to protect high voltage assets by isolating the faulted section from the rest of the network. Fuses may also perform a similar function depending on network configuration. The main types of relays used in the Aurora network are: electromechanical, analogue and digital.

Translay protection systems have been used extensively on the Dunedin 33kV sub-transmission networks. The existing Translay system used in the Aurora network is an electromechanical design and the system is at the end of its operational life. Most of the existing Translay protections were installed as part of the cable installation and the age of these devices varies between 30 and 52 years.

Current assumptions are that the age of protection relays is generally the same as the associated switchgear. Protection relays are generally upgraded to modern IED relays when the associated switchgear is replaced.

Aurora does not currently have specific age profile data for the protection relays; however this issue is being addressed as part of the data completeness and accuracy review process.

Older feeder protection relays are proposed to be upgraded to SEL relays and this forms part of the SCCP programme. The benefits of installing these relays are:

- Implementation of auto reclose on feeders is made easier
- Improved performance through implementation of separate sensitive earth fault and normal earth fault protection
- the provision of additional fault data & detailed post fault analysis as the SEL relays are modern IED devices that can communicate directly with the SCADA RTU

Maintenance Plan

Current routine and preventative protection system maintenance includes:

Biannual tests for protection pilots - most of the pilot circuits are underground cables, generally run with 33 kV cables. They are tested biannually for continuity, insulation resistance, and attenuation.

Six year inspections for earth connections - above ground earth connections, for all equipment, are inspected and maintained at six-yearly intervals. Sample underground connections to the main earth grid are also checked at six-yearly intervals for physical deterioration. Earths identified during routine inspection as requiring attention will be refurbished as required.

The future requirements for Aurora's protection systems maintenance planning will be reviewed and revised where necessary as part of the SCCP programme delivery.

Creation/Upgrade and Renewal Programme

See Table 5.10 for proposed SCCP programme.

Disposal Plan

Disposal is as per proposed decommissioning policy outlined in Section 5.4.3.

5.5.18.4 Load Management Systems

Dunedin Load Management

Load management in the Dunedin area is via 18 K22/Decabit 1050 Hz 11 kV/6.6 kV ripple injection plants at each zone substation. The injection plants are controlled via the Dunedin SCADA master station. All ripple receiver relays are owned by Delta or Electricity Retailers, except for street lighting control relays in distribution substations, which are owned by Aurora. There are approximately 45,000 receiver relays on the Dunedin network and Aurora owns 2195 ripple control relays that are used to switch street lighting circuits.

A new 317 Hz 33kV injection system was installed in 2011 adjacent to the South Dunedin and Halfway Bush GXP's and operates in parallel with the 1050Hz system. Ripple receivers will be progressively changed from 1050 Hz to 317 Hz, with 1050Hz injectors progressively removed.

Central Load Management

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants. These injectors are all solid state units with a nominal life of 20 years. The Central injection plants are controlled by a custom made system dating from 1996. The load control system used in Central Otago was originally installed well before the SCADA system and therefore ran on equipment completely separate from the SCADA system.

A PLC located at the Alexandra Substation makes all the load control decisions. Load control data to and from the three Transpower GXP points of Frankton, Cromwell and Clyde, plus data from the local Generation stations is fed into the PLC at Alexandra. This load control data consists of the GXP metering pulses, generation metering pulses, channel statuses, ripple plant keying and ripple plant alarming.

Power Factor Correction Equipment

Some consumers have installed power factor correction equipment in order to comply with Aurora policy to maintain a power factor of at least 0.95. TrustPower has connected 15MVAR of capacitors at the Mosgiel substation to mitigate the adverse effect on the power factor at the Halfway Bush GXP due to the installation of the 36 MW Mahinerangi wind farm.

Maintenance Plan

Ripple signal checks, carrying of strategic spares stock, replacement units for rental and a fault callout service are currently carried out on an annual basis via the routine contactor checks. Contacts will be renewed as part of this where necessary.

Motor-generator sets are being monitored and routine maintenance will be carried out where identified as necessary.

The solid state coupling cells at North East Valley zone substation and in the Central network are virtually maintenance free.

CO₂ flood systems in load control coupling cell cubicles are inspected annually. Pressure cylinders are tested at regulated intervals dependent upon age (5 year intervals for pressure tests). Inspection is carried out internally, with repairs and pressure testing conducted by external contract. The roll out timeframe is for 317Hz ripple units in consumer sites will dictate the decommissioning timeframe of the existing 1050Hz plants / CO₂ installations at each zone sub.

Replacement Plan

Ripple Injection – zone substations

The Alexandra 33 kV injection equipment in the Central network area has been identified as now having reached the end of its expected service life with no critical spares available.

While North East Valley 33 kV injection equipment is still within its expected service life there are no critical spares available.

Through the outsourced maintenance contract for the 33 kV injection equipment, rental units are available and would be hired while new units were acquired.

Cromwell upgrades are now complete.

Dunedin Street Lighting Ripple Control Receivers

Aurora owns 2195 ripple control relays that are used to switch street lighting circuits. These relays need to be changed from 1050Hz units to 317Hz units to facilitate the decommissioning of the 1050Hz injectors. The actual replacement program has yet to be finalised but an allowance of \$80,000 per year for five years has been made for the conversion work.

5.5.18.5 Metering Systems

In the Dunedin area, Aurora receives meter pulses from the Transpower GXP metering. Check meters are installed at each GXP, and at the Waipori generating station. The data from these meters is processed by data loggers and monitored by the Dunedin SCADA. All load monitoring at Dunedin zone substations is done via the SCADA system.

In the Central area, Aurora receives meter pulses from the Transpower GXP metering and also has check meters at the Cromwell and Clyde GXPs only. Aurora does not have check meters at Pioneer Generation sites but receives load meter pulses from these sites via a UHF network. Central metering data is processed and stored via a load control PLC and associated load control computer at Alexandra.

Replace Dunedin GXP Check Meters

The check meters at Halfway Bush and South Dunedin are nearing the end of their economic life. There have been un-resolved accuracy issues with the South Dunedin units. The replacement may include the upgrade of the systems used for logging the metered data. Additional investigation and design work is required to detail the required works but an allowance has been made to carry out the work in 2012, with an estimated cost of approximately \$80,000.

5.5.19 Mobile Substations/Generation

Asset Description

Aurora owns three mobile distribution substations with a voltage configuration of 11kV/6.6 kV/400V. One 500kVA unit is based at Cromwell, with a 300kVA and 500 kVA unit based in Dunedin. These units are standby units for continuation of supply during transformer replacements or repair be they planned or unplanned and are custom fitted to commercially available truck chassis.

Additionally Aurora owns a 5 MVA 66/33/11/6.6 kVA mobile substation which is based at Cromwell as a backup for Zone Substation outages or Zone Substation transformer maintenance. Due to the scale of the 5MVA mobile substation the setup is on a four axle stepped semi trailer with front and rear hydraulic outriggers for levelling and stabilising when deployed.

With the establishment of Cardrona Zone Substation, the temporary containerised 500kW generator that was installed in the Cardrona valley to provide additional capacity during the ski seasons has now been removed and currently not in service. It's future is under review.

Asset Capacity/Performance and Condition

The performance of mobile distribution substations is generally good; the majority of repairs are more related to the vehicle carrying the unit involving WOF or COF compliance.

Performance of the 5MVA mobile substations is generally good and again the majority of repairs are more related to the vehicle carrying the unit involving WOF or COF compliance.

With the containerised 500kW generator future being under review it is currently in storage.

The 5MVA mobile substation exceeds the NZ Transport Agency "Vehicle Dimensions and Mass 2002" Rule 41001 in height and width and as such has been granted an exemption under Exemption VDM09/079 and associated document B990258.

Central based 5MVA fitted to TMC Trailer Four axle stepped semi-trailer.

Asset Data

Data currently held includes past registration and ownership forms in hardcopy on file.

Maintenance Plan

On a regular basis the mobile distribution substations are condition assessed with checks as per RS30, electrically tested and maintain valid WOF's and COF's.

Replacement Plan

There is currently no programmed replacement expenditure allocated to this asset category.

Creation/Acquisition and Disposal Plan

There are currently no plans to dispose of these assets. The purchase of an additional mobile generator is being considered in order to reduce the risk and cost associated with transformer sites on the distribution network that no back-up supply options available.

5.5.20 Other

Ladders, portable earthing equipment, and safety gear

All ladders, portable earthing equipment, and safety gear used in zone substations are inspected or tested at six-monthly intervals. Anything identified as requiring refurbishment during these six monthly inspections will be refurbished as required.

Towers - Port Chalmers to Peninsula Harbour Crossing Upgrade

There are six towers associated with the Port Chalmers 11 kV feeder 7 harbour crossing. These towers were installed in 1960 and have been relatively maintenance free until now. Linetech examined the towers and has recommended that, if they are to be retained, they should be cleaned and repainted.

These are strategically important as they provide a robust 11 kV feeder to the Otago Peninsula. It is estimated that it would cost \$150,000-\$200,000 to refurbish each tower with a total cost of \$900,000 to \$1.2 million. Investigations are underway to determine if it is feasible and economic to install a second submarine cable crossing. A provisional allowance has been made for this project.

5.6 Operations & Maintenance Forecasts

Operational expenditure is split into 4 main categories, as per the new Electricity Distribution (Information Disclosure) Requirements 2012. Expenditure allocations are listed below (as a % for 2013/14) and forecasts presented in the tables that follow¹⁰.

Service Interruptions & Emergencies – 41% of total maintenance expenditure allocation

Vegetation Management – 13% of total maintenance expenditure allocation

Routine and corrective maintenance and inspection – 33% of total maintenance expenditure

Asset Replacement and Renewal – 12% of total maintenance expenditure allocation

A third party damage allowance of \$750,000 per annum is now included in the Table 5.10, in the service interruptions category. The proportion of overhead to underground conversion works that would be expensed, such as removal of overhead lines, is now included in refurbishment and renewal estimate above.

Table 5.10 - Operations & Maintenance Costs Summary (\$000)

Maintenance Expenditure (\$000)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Service Interruptions and Emergencies	4,040	4,141	4,244	4,350	4,459	4,570	4,685	4,802	4,922	5,045
Vegetation Management	1,312	1,345	1,378	1,413	1,448	1,484	1,522	1,560	1,599	1,639
Routine, corrective maintenance & inspections*	3,280	3,362	3,446	3,532	3,620	3,711	3,803	3,898	3,996	4,096
Replacement & Renewal**	1,191	1,221	1,251	1,282	1,314	1,347	1,381	1,416	1,451	1,487
Total	9,822	10,068	10,319	10,577	10,842	11,113	11,390	11,675	11,967	12,266

*See Table 5.11 for detail

** See Table 5.12 for detail

The maintenance and renewals expenditure lines above are further disaggregated in the tables below to show costs against each asset category.

Table 5.11 - Routine, Corrective Maintenance & Inspections Expenditure by Asset Category (\$000)

Asset Category	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Subtransmission	115	118	120	123	127	130	133	136	140	143
Zone substations	1,070	1,097	1,124	1,152	1,181	1,211	1,241	1,272	1,304	1,336
Distribution and LV Lines	684	701	719	737	755	774	793	813	834	854
Distribution and LV Cables	31	32	32	33	34	35	36	37	37	38
Dist. substns & transformers	117	120	123	126	129	133	136	139	143	146
Distribution Switchgear	11	11	11	12	12	12	12	13	13	13
Secondary Assets	101	103	106	108	111	114	117	120	123	126
Other	1,151	1,180	1,209	1,240	1,271	1,302	1,335	1,368	1,402	1,438
Total	3,280	3,362	3,446	3,532	3,620	3,711	3,803	3,898	3,996	4,096

¹⁰ Constant pricing operational expenditure was inflated to reflect forecast nominal prices from CPI growth data 2013/14 – 2016/17 sourced from the New Zealand Treasury Half Year Economic and Fiscal Update (Dec 2012). The Treasury CPI growth value from 2016/17 was taken to calculate nominal pricing over 2017/18 – 2022/23 in lieu of available forecast data for this period.

Table 5.12 - Replacement and Renewals Expenditure by Asset Category (\$000)

Asset Category	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Subtransmission	137	140	144	147	151	155	159	163	167	171
Zone substations	0	0	0	0	0	0	0	0	0	0
Distribution and LV Lines	667	684	701	719	737	755	774	793	813	833
Distribution and LV Cables	0	0	0	0	0	0	0	0	0	0
Dist. substations & transformers	384	393	403	413	424	434	445	456	468	479
Distribution Switchgear	3	3	3	3	3	3	3	3	4	4
Secondary Assets/Other	0	0	0	0	0	0	0	0	0	0
Total	1,191	1,221	1,251	1,282	1,314	1,347	1,381	1,416	1,451	1,487

6 Network Development

6.1 Introduction

This section outlines the network development plan and capital expenditure required to maintain, enhance and develop the operating capability of Aurora's system.

The overall aim of this section is to clearly justify investment needs and identify funding requirements over the short, medium and long term. The key drivers for capital investment were highlighted in Section 2.4, and included:

- growth in demand (existing and new consumers)
- enhancement of network reliability and security
- meeting legislative requirements, safety and reliability standards
- replacement of aging assets
- community expectations
- emergency preparedness

The sections that follow provide an outline of the planning criteria, assumptions and prioritisation frameworks applied to Aurora's development planning processes. Growth and demand forecasting and predictions are then presented followed by the proposed plans to address the network development requirements.

The forecast capital expenditure for each region is presented on the following page and detailed further in Sections 6.5 and 6.6. Definitions for the expenditure categories are outlined below (based on the Commerce Commission determination information).

Definition of capital & operational expenditure categories

Reason for Work / Primary Driver	Sub-Category	Commerce Commission description
Consumer connection		Establishment of new customer connection point or alterations to an existing connection point, and includes expenditure on assets relating to connection assets for which expenditure is recoverable in total, and injection and off-take points of connection
System growth		A change in demand or generation on a part of the network resulting in the need for extra capacity or additional investment to maintain current security and/or quality of supply standards <i>due to increased demand</i> . Includes SCADA and telecommunications assets.
Asset replacement and renewal		Expenditure on assets for replacement and renewal
Asset relocations		Resulting from the need to relocate assets due to 3rd party requests, requests from the roading authority or other needs. Also includes under-grounding of overhead network assets.
Reliability, safety and environment	Quality of supply	The need to meet improved security and/or quality of supply standards to reduce overall interruption/fault rates on the network, and minimising SAIDI and SAIFI.
	Legislative and regulatory	New regulatory or legal requirement resulting in the creation of, or modification to network assets.
	Other reliability, safety and environment	To improve network reliability, safety or to mitigate the environmental impact of the network.

Row Labels	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Dunedin										
Asset relocations	1,363	1,175	1,127	1,127	1,127	609	621	633	646	659
Asset replacement and renewal	2,871	2,851	11,630	5,494	7,364	4,601	4,882	4,966	1,186	1,186
Consumer connection	1,347	1,145	1,100	1,100	1,100	1,200	1,200	1,200	1,200	1,200
Rel, Safety and Env: Other	410	890	350	-	180	-	-	-	-	-
Rel, Safety and Env: Quality of supply	150	100	100	100						
System growth (blank)	100	100	100	100	100	1,000	3,475	4,825	100	100
Dunedin sub-total	6,241	6,261	14,407	7,921	9,871	7,410	10,178	11,624	3,132	3,145
Central										
Asset relocations	1,918	1,222	1,199	1,399	1,174	667	680	693	707	721
Asset replacement and renewal	3,455	2,310	1,555	1,410	1,060	1,060	1,000	1,000	1,000	1,000
Consumer connection	5,391	4,583	4,402	4,402	4,402	7,000	7,000	7,000	7,000	7,000
Rel, Safety and Env: Other										
Rel, Safety and Env: Quality of supply	1,510	366	20							
System growth (blank)	6,764	10,153	8,090	6,055	4,355	3,250	1,500	5,800	2,350	2,350
Central sub-total	19,038	18,634	15,266	13,266	10,991	11,977	10,180	14,493	11,057	11,071
Dunedin/Central										
Asset replacement and renewal	923	1,550	740	540	370	370	370	370	370	370
Rel, Safety and Env: Other	300	240	120	120	120	120	120	120	-	-
Rel, Safety and Env: Quality of supply	100	200	200	200	200	200	200	200	200	200
System growth	80	80	80	80	80	80	80	80		
Dunedin/Central sub-total	1,403	2,070	1,140	940	770	770	770	770	570	570
Grand Total	26,682	26,965	30,813	22,127	21,632	20,157	21,128	26,887	14,759	14,786

6.2 Planning Criteria

When a deficiency is identified, the process for considering options and developing solutions commences. There can be several options available for resolving issues or risks identified and not just limited to capital expenditure for new or upgraded assets. Other options may include: do nothing, demand management, operational solutions. A range of factors are used to assess the viability of each solution, including (but not limited to) compliance with safety design standards, security of supply, quality, capacity, and capital return.

6.2.1 Security

Aurora recognises security of supply as being fundamental to ensuring a network continues to perform. It is the ability to meet demand and continue to provide a service in circumstances when equipment fails.

The more secure a network, the greater ability to continue to perform and/or the faster recovery time when a fault on the system occurs. Reliability on the other hand is different in that it is a measure of how the network actually performs e.g. frequency or duration of interruptions to supply.

By increasing the security of the network the potential for single points of failure can be mitigated. Appendix B outlines the basic guidelines for supply security; however, in all cases, if the GPD exceeds the given range, any reinforcement expenditure must be justified by economic analysis.

Security is factored into planning the development of Aurora's network by closing supply loops when economically viable. This statement holds true for both high voltage feeders and low voltage networks. During the initial scoping and appraisal stage for feeder or distribution substations, considerations are made for incorporating feeder interties along with low voltage connections between networks.

6.2.2 Power Quality

6.2.2.1 Voltage Magnitude

Setting voltage criteria is another important step used by Aurora in order to ensure that regulatory requirements are met so that the voltage is maintained between $\pm 6\%$ at the point of common coupling.

Areas within Aurora's network that may experience changes in quality are associated with long rural distribution feeders. The customers near the end of these feeders have UTL data loggers installed that telemeter the consumers voltage to Aurora for analysis. Remedial works are considered if the consumer's voltage is outside the regulated limits for more than 5% of the year.

The placement of voltage regulators is a method used to maintain voltage levels on rural feeders. The preferred approach is to avoid the use of voltage regulators if it can be economic to construct a new zone substation. Zone substations are seen as a more dynamic approach to managing voltage magnitude particularly if loading is predicted to increase on the line in question.

Network reconfiguration is also a method used if applicable to help ensure voltage magnitude requirements are maintained.

6.2.2.2 Harmonics

It is recognised that low harmonic levels must be maintained on Aurora's network to ensure no undue interference to all customers and to avoid unnecessary conductor upsizing.

In 2013 Aurora released a new connection requirement for the level of voltage and current harmonic distortion allowed at the point of common coupling. This is seen as a timely addition to the connection requirements as it ensures the network will be designed in an effective manner so that connections do not result in unnecessary maintenance expense.

The rural harmonic connection requirements can be found on the Aurora Energy website.

6.2.3 Equipment Ratings

Equipment ratings are used in development planning to allow new additions to meet identical or greater capacity requirements. Capacity ratings of key asset groups are specified in Table 6.1.

Table 6.1 – Assignment of Equipment Ratings

Equipment	Rating Allocation
Zone substation transformers ONAN	Winter peaking transformers are operated to 120% of nominal rating by taking advantage of low ambient temperature during high load periods and cyclic load profile as per AS 2374.7 "Loading guide for oil immersed transformers".
Transformers ONAN/OFAF [†]	Manufacturer assigned emergency rating.
Overhead lines*	Winter night and summer day ratings assigned in accordance with IEEE Std 738 - 1993 (also see Section 6.2.3.1)
Switchgear	Manufacturer's assigned rating, no overload permitted.
Current transformers	120% of nominal rating unless rated for extended thermal range.
Cables*	Some 33 kV cables have had ratings assigned by consultants after investigation of specific installation conditions. For all other cables the manufacturer's standard data sheet ratings are used including ambient temperature, soil thermal resistivity and cable proximity.
Distribution transformers	Transformers with a normal residential area load profile can be loaded to 150% of nominal rating. For other loads 130% of nominal rating.

*see comments of feeder ratings below
[†] refer to Glossary of Terms

A feeder rating is the minimum of its circuit breaker rating, outgoing cable rating, or CT thermal rating. Some feeders have constraints beyond the outgoing cable. Feeders are not permitted to exceed their rating. It is desirable to be able to transfer the entire load on a feeder to adjacent feeders in the event of a fault on the outgoing cable. Generally, there are several options to off-load most feeders.

Aurora has a "Feeder Loading" database that provides calculation of the ability to off-load a feeder. When it becomes impossible to completely off-load a feeder during peak load times, analysis is carried out to assess if the cost of eliminating the off-loading constraint is economic.

6.2.3.1 Overhead Conductor Rating

Historically overhead conductor on Aurora's network has been designed and operated to 50°C as per regulation requirements of the period. The current capacities of these lines are specified in accordance with Table 6.2.

Table 6.2 – Ratings of ACSR Overhead Conductor at 50°C

Conductor	Ratings (Amps)		Volt Drop %/MVA/km		
	Winter	Summer	33 kV	11 kV	6.6 kV
Wolf	542	385	0.026	0.228	0.631
Dog	374	226	0.035	0.31	0.859
Mink	300	213	0.051	0.455	1.256
Ferret	231	164	0.071	0.634	1.742
Squirrel	148	105	0.131	1.168	3.179

All new overhead line is designed for a temperature rating of 75°C. Therefore when assessing existing overhead line ratings the value presented in Table 6.2 for 50°C is used unless explicitly stated. This ensures appropriate clearances are met due to sag.

The current capacity of overhead conductor that will be operated at 75°C for all new installations, is in accordance with Table 6.3. All irregularities to this table are dealt with on a case by case basis. Sub transmission overhead lines may have differing values.

Table 6.3 – Ratings of ACSR Overhead Conductor at 75°C

Conductor	Ratings (Amps)		Volt Drop %/MVA/km		
	Winter	Summer	33 kV	11 kV	6.6 kV
Wolf	659	545	0.026	0.228	0.631
Dog	455	378	0.035	0.31	0.859
Mink	341	285	0.051	0.455	1.256
Ferret	269	226	0.071	0.634	1.742
Squirrel	175	148	0.131	1.168	3.179

6.2.4 Utilisation Thresholds

Utilisation threshold is the planning limit on the ratio of an assets maximum allowed capacity compared to that of the expected/actual loading. Utilisation thresholds are closely related to capacity determination as they influence the formula used to determine the size of distribution transformers placed in the network.

The questions posed around where the threshold should sit for utilisation is challenging due to the probability used to determine the load of a domestic street versus an industrial outfit, i.e. industrial is more predictable than residential. Once this is understood, then a picture of the expected yearly peak loading is obtained along with whether the probability that Aurora's policy of 120% transformer rating could be exceeded.

When dealing with n-1 the utilisation threshold has new meaning as the requirement for the system will involve a single line of equipment being able to carry the total capacity, therefore utilisation will be under 50%. n-1 systems are therefore justified and planned through other methods. Another example where this ratio falls short is the rating of lines when the line has been designed to carry increased load in a contingency situation.

6.2.5 Capacity Determination

When a capacity or security gap is identified, it is important to consider different options as solutions. Determination of capacity required is dependent on two aspects: (i) expected peak capacity for the assets economic life; and (ii) the standardised capacities available.

The design and construction of Aurora's 11kV and 6.6kV feeder networks follow a standardised design which inherently produces stepped capacity levels. This is considered acceptable as it increases efficiency in network construction therefore keeping costs down.

Existing loading and hence available capacity is measured on each feeder through half hourly data records and via maximum demand indicators located in distribution substations. This information is collected yearly and aids the timing of upgrades and replacements.

6.2.6 Standardisation

There is constant and progressive movement to refine and add new network standard drawings and procedures to the design and construction of Aurora's network. This extends from standard earthing drawings through to complete project tender packages.

The type and sizes of transformers used on Aurora's network are identified in network standards. This allows for easy replacement along with a reduction in the number of required strategic spares. Due to the Dunedin and Clyde Earnsclough network operating at 6.6kV all new transformers purchased for these areas are dual ratio, offering the ability in the future to operate at 11kV. Using dual ratio transformers has increased costs therefore standardising transformer sizing is an important aspect in the management of Aurora's network.

Aurora has a register of network standard practices and drawings, which are intended as the model for good design and therefore any variation must be approved by Aurora.

6.2.7 Energy, Demand and Growth (see Growth & Demand – Section 6.4)

Energy and demand growth is influenced by a variety of factors. Growth in peak demand is what primarily drives network development. Changes in population and population behaviour are the main factors that affect load growth, each being influenced by a number of variables (or strategic drivers) as outlined in Section 2.

Estimating the size and location of future loads is integral to effectively plan for the future of Aurora's network. However, there is also a degree of uncertainty associated with any type of forecasting, so it is important for load forecasting to be viewed as a guide to determining an approximate time for intervention and a trigger to further develop a higher level of accuracy as that time nears.

A key input to the planning process is half hourly load data. This is analysed after each winter for all grid exit points, zone substations and HV feeders. Section 6.4 contains detail regarding how growth and demand forecasting is carried out for network planning and decision-making.

6.2.8 Economic Analysis

Probabilistic analysis is used by Aurora to calculate the annual cost of energy not supplied for the selected network configuration. Upgrades will proceed when the net present value of the energy not supplied is greater than the cost of the upgrade. The value used for energy not supplied is detailed in Table 6.4.

Probabilistic analysis is also applied at the HV feeder level. The trigger for analysis is when it is not possible to fully off-load a feeder onto adjacent feeders at peak load times or the feeder has reached 85% of its thermal rating. On rural feeders, it is normally voltage drop that determines the maximum capacity of a feeder and not its thermal capacity. Typically 5% is the maximum volt drop tolerable in the HV network; however, this can be exceeded on some rural feeders where consumers typically have their own transformer and there is minimal LV distribution.

Aurora generally selects the option with the lowest life-cycle cost, by determining the NPV of the following costs associated with a project: A discount rate of 9.8% is used.

- initial construction;
- on-going maintenance;
- consumer outage costs associated with construction;
- cost of losses (presently valued at \$0.07 per kWh) (see below)
- on-going consumer outages (as per Table 6.4).

The cost of an outage using probabilistic analysis is determined by multiplying all the following parameters: value of energy not supplied; quantity of load not supplied; probability of an outage; probability of outage occurring during an at risk time; likely outage duration.

Each of these parameters is discussed below

Following a review by external consultants in 2010; the following Values of Lost Load were adopted:

Table 6.4 – Cost Allocated to Energy not Supplied

Type of Interruption	Value of kWh Unserved
Unplanned – residential	\$10
Unplanned – other	\$50
Planned – residential	\$ 5
Planned – other	\$25

Other factors that may be taken into consideration during project selection are environmental impact, community feedback, and future development options.

Value of Energy not Supplied

The value of energy not supplied, (also known as Value of Lost Load), is detailed in Table 6.4 above.

Quantity of Load Lost

Load duration data is used to determine the annual hours at risk and determine the mean load not supplied during an outage. Growth factors are applied when applicable.

Probability of an Outage

The probability of failure is assessed by using engineering judgement in considering past and likely future failure rates. Judgement is required as pure consideration of past failure rates tends to under predict the future. Typical default values are shown in Table 6.5 below.

Table 6.5 – Equipment Outage Probabilities

Equipment	Annual Fault Probability	Units
66 or 33 kV overhead line	0.06	per kilometre
HV overhead line	0.1	per kilometre
HV underground cable	0.05	per kilometre
Power transformer	0.005	per unit
Circuit breakers	0.005	per unit

Probability of Outage During “At Risk” Time

The “at risk” time is when the load on a system exceeds the n-1 capacity of the system (plus the shoulder period just outside such times) but within anticipated repair times. Load duration data is used to determine the annual hours at risk. Growth factors are applied when applicable.

Outage Duration

The duration of the outage will depend on the equipment that has failed, its location, and the nature of the failure. Typical outage times are given in Table 6.6 below:

Table 6.6 – Typical Equipment Outage Times

Equipment	Outage Time	Notes
Overhead line	1 to 6 hours	Required to locate gas leak
33 kV oil cable	Up to 2 weeks	
33 kV gas cable	1 to 2 weeks	
PILC and XLPE cables	12 to 24 hours	

Power transformer <= 5 MVA	6 to 12 hrs	Time to deploy mobile sub
Power transformer > 5 MVA	1 week to one year	Faults can range from minor tap-changer issues to total transformer failure

6.2.9 Non-Network Solutions

There are several alternatives available instead of investing in new infrastructure when the network becomes constrained. These include demand-side management, distributed generation (see 6.3.1) and more recently, the potential opportunities from smart metering (although these are yet to be realised).

6.2.9.1 Demand Side Management (DSM)

Aurora offers a demand management program to consumers with a capacity greater than 150 KVA who have the potential to manage their Congestion Period Demand (CPD). As at 2012, 51 customers, consisting of 105 ICP's had signed up to this program. Aurora otherwise applies the pricing principals as set out in Part 6 of the Electricity Industry Participation Code 2010.

Aurora's CPD pricing methodology is one of the main mechanisms that enables Aurora to better utilise its distribution assets. This financially rewards the operation of standby generation plant during network congestion periods. Over the few years, a number of consumers completed alterations to their diesel generation plant to allow it to operate during congestion periods.

Ripple Control

Ripple signal injection is used to signal congestion periods, and to offer an appliance-switching service that is voluntary but financially attractive. The switching service is predominately used for water heating, space heating, and pumping loads. Ripple control is considered to be a cost effective DSM tool. Ripple controls involves sending signals through the network to control hot water cylinders. Aurora's use of ripple control has contributed to a 38MW difference between estimated peak demand and actual peak demand, requiring that much less investment in network capacity.

Distributed generation is encouraged to operate during congestion periods and this is facilitated by the CPD ripple signal. Further information on this DSM program is available on the Aurora website www.auroraenergy.co.nz. Also on the website, is the current status of the CPD demand ripple channel and predicted CPD periods.

Smart Metering

The application of smart meters that provide half hourly metering for all consumers could encourage the moving of further load away from peak periods. This process is under the control of Electricity Retailers and Metering Service Providers. Aurora will monitor this technology with a view to assessing if it can be used to encourage consumers to reduce their demand during faults on the Aurora network which could enable Aurora to defer some network upgrades.

6.2.9.2 Do Nothing

The option to 'do nothing' must always be considered as part of option analysis and selection process. This may mean that it may be accepted that some consumers may face a reduction in service levels. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if analysis was provided to the Chief Executive and Directors that the do nothing option did not represent an unacceptable increase in risk to the business.

6.3 Growth and Demand Forecasting

The following sections describe how growth and demand forecasting is carried out for Aurora's network, discusses how contributing factors are considered in the estimation process and how these are subsequently applied to network planning and decision-making.

Demand Forecasting Methodology

Historic trends provide a baseline from which growth in energy consumption can be estimated from. Aurora derives load forecasts from historic trends in growth and subsequently adjusts these to reflect the impact of other significant factors such as distributed generation (see section 6.3.1), demand management and pricing methodologies, known load increases, engineering judgement and other variables such as weather patterns, changes in land-use and development requirements that may be driven by territorial authority district plan changes. Demand forecasting is undertaken by Aurora on an annual basis

Half hourly loading data is collected from GXP's and zone substations. This data is uploaded into an excel spreadsheet and an assessment of future loads is carried out using both growth (exponential) and linear prediction functions.

An initial point mid-way between the growth and linear predictions is taken from this and represents the growth value to be applied for planning purposes.

The half-hourly data is also applied to HV feeder analysis. At the HV feeder level, the ability to off-load each feeder is checked. Feeders that are identified as being 'at risk' are subject to further assessment to obtain further detail on predictions. At risk feeders are those deemed to be near their maximum rating or cannot be fully off-loaded.

Other variables taken into consideration as part of the demand forecasting process include information on sites for potential future development, seasonal variation and other temporal factors such as the day of the week or the timing of school/public holidays throughout the year. Other database and GIS information is also used for identifying the location and expected electrical demand of proposed developments such as subdivisions, which assists with refining HV feeder load predictions.

Growth and demand predictions are provided in Section 6.5

6.3.1 Distributed Generation

Although the main purpose of Aurora's distribution network is to deliver energy from the GXP's to consumers, there are circumstances where it can be more economic for the consumer to provide a source of energy – this is referred to as distributed generation. This AMP uses the term 'distributed generation' in place of embedded generation; it is considered to mean the same thing.

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. On the downside, however, distributed generation can also produce adverse effects on the network, including harmonic distortion, localised congestion, and voltage instability. Accordingly, care is required when approving new distributed generation connections.

Aurora has guidelines and application information for the connection of distributed generation published on its website at www.auroraenergy.co.nz. Aurora examines each proposal with regard to the likely effect that the distributed generation will have on Aurora's network.

Aurora currently has 130.9 MW of distributed generation connected to its network. Hydro generation remains the predominant energy source for distributed generation on the Aurora's network at 61.0% of total generation capacity. Small-scale photovoltaic generation, at the other extreme, although comprising 55% of generation connections, comprises only 0.2% of total generation capacity.

Over the past year there has been a significant increase in applications for distributed generation connections, being approximately 360% more than the previous year. This increase has mainly occurred in the Central Otago area, affecting the Clyde, Cromwell and Frankton GXP areas. Most applications have been for relatively small domestic connections (<10kW) and in most cases have minimal network impact, although over time the cumulative impacts of these should be further considered, particularly if evidence of clustered generation emerges.

The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 requires Aurora to provide a 5-year forecast of distributed generation connections and capacity. Aurora's forecasts are summarised below. There is significant uncertainty in the forecasts, due to the relatively embryonic nature of small-scale distributed generation in New Zealand.

The degree to which the recent rate of applications to connect distributed generation will be sustained is uncertain. While the cost of photovoltaic cells is understood to be falling, aided by relatively low cost manufacture out of China, the cost of a distributed generation installation will remain out of reach for many consumers, particularly

where retro-fitting to an existing dwelling is required. The forecasts below allow for the planned connection of Contact Energy's Lake Hawea generation project in 2017/18.

	2013	2014	2015	2016	2017	2018
DG Connections	59	157	284	428	592	769
DG Capacity (kW)	131,059	131,783	132,826	134,059	135,499	154,081

Commercial arrangements for distributed generation vary. For small distributed generation (generally below 10kW), 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 system assets, and Aurora has developed a standard distributed generation Use-of-System agreement as a basis for commercial negotiations. The standard agreement has been developed with reference to the Code and appropriate conditions in retail Use-of-System agreements. Aurora considers that this approach maintains a degree of industry consistency and standardisation.

6.4 Project Prioritisation

In general, the prioritisation of capital projects is linked to Aurora's key activity objectives (Section 2) and associated service level attributes for Safety, Reliability, Quality, Responsiveness, Compliance, Efficiency and Financial sustainability; underpinned by Continuous Improvement. Table 6.7 below provides an indication of project category and subsequent priority:

Table 6.7 – Project Priority List

Priority	Project Category
1	Projects to eliminate significant health and safety issues.
2	Projects to resolve consumer voltage outside statutory limits.
3	Consumer driven projects such as new connections and subdivisions.
4	Projects to provide for load growth.
5	Projects to improve reliability that are not related to load growth. Projects in this group with the highest expected benefit to cost ratio are implemented first.
6	Overhead to underground conversion projects.
7	Renewal projects where there is no immediate threat to network reliability or health and safety issues.

Risk-based decision making framework

The review of Aurora's planning and forecasting assumptions and uncertainties will continue in 2013/14, with consideration given to the current decision-making criteria and prioritisation methodology. Aurora is working towards providing more transparency on reasons why particular solutions or options have been chosen, and their priority. Focus will continue on the refinement and application of risk-based decision-making criteria.

6.5 Growth and Demand Predictions

Network energy through put for the year ending March 2012 was 1,392 GWh (including distributed generation), which was an increase of 52MWh (3.9%) on the previous year. Overall demand growth on Aurora Energy's network has been mixed over the past 4 years. The number of small customer connections fell slightly as did electricity consumption. The number of medium-sized customer connections grew around 10%. Medium-sized customers increased their electricity consumption 2%.

Central

Modest population growth is expected in the central area supplied by the Aurora network (Clyde, Frankton and Cromwell) over the next few years. The 5-year maximum system demand growth forecast for the Central network is 2.6% p.a (based on the 2012 Information Disclosure)

Aurora expects growth in electrical demand to continue, which is the main driver for capital expenditure in this area. This growth is anticipated to be driven mainly through large-scale irrigation, with subdivision development having slowed in the recent past. Ski-field operations have a significant impact on demand, and peak loads are usually seen during the winter months. If this is coupled with very cold weather it can cause a large increase in demand in the Wanaka and Queenstown areas. Aurora has determined that it is not economic to install additional assets to maintain normal supply security levels during these infrequent events.

Dunedin

Population growth is expected to remain relatively static in Dunedin over the next 10-20 years. For example, under the Statistics New Zealand medium growth scenario, Dunedin is projected to have an annual growth rate of 0.25% over the next 10 years (compared to a growth rate of 0.85% nation-wide). Growth in electrical demand is therefore expected to average between 0% and 1%, but there may be localised areas where growth will exceed this. Capital expenditure in the Dunedin area will therefore mainly be driven by the replacement of ageing assets, the conversion of overhead distribution to underground, and reliability improvements. Although, extreme cold weather events (such as a three-day snowfall that occurs during the week, and outside of the school holiday period) can add an additional 10% to the Dunedin peak demand.

6.5.1 Grid Exit Points

The historic and projected peak demands (in MW) for the network areas associated with each Grid Exit Point (GXP) are shown in Table 6.8; the demands are equal to the demand on the GXP plus embedded (distributed) generation. The Energy use normalised in 2002 GWh for each GXP is shown in Figure 6.1 and the load factor by GXP is shown in Figure 6.2.

The reduction in Dunedin load factors is attributed to the loss of high load factor industrial load which has been replaced by low load factor weather dependent residential and commercial load.

The demands at all GXPs during the 2012 winter were equal to or higher than predicted in the 2012 AMP, with the exception of South Dunedin. This is different compared to that observed during the 2011 winter, where all were lower than predicted (except for Halfway Bush), attributable to the mild winter and the impact of the economic down turn.

Table 6.8 - GXP area peak demands

Calendar Year			Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	
2004	Actual	GXP Off take + Embedded Generation (MW)	15.6	21.5	41.4	126	67.0	
2005			17.2	24.4	41.8	126	66.1	
2006			16.3	25.1	45.1	125.1	70.2	
2007			18.2	30.6	49.7	130.6	71.0	
2008			16.4	28.0	48.0	124.0	70.6	
2009			16.8	30.5	47.7	130.6	72.2	
2010			16.4	31.4	49.5	121.3	71.7	
2011			16.6	29.9	48.7	128.7	72.2	
2012			17.4	31.8	51.9	128.5	70.5	
2013	Predicted		17.0	33.3	52.2	128.1	72.4	
2014			17.1	34.3	53.2	128.7	73.1	
2015			17.2	35.3	54.2	115.4	87.9	
2016			17.3	36.3	55.2	116.0	88.7	
2017			17.4	37.3	56.3	116.6	89.5	
2018			17.5	38.3	57.3	117.2	90.3	
2019			17.5	39.3	58.4	117.8	91.1	
2020			17.6	40.4	59.5	118.4	91.9	
2021			17.7	41.5	60.6	119.0	92.8	
2022			17.8	42.6	61.7	119.6	93.6	
2023			17.9	43.7	62.8	120.3	94.4	
Past Growth Rate (Trend 2006 to 2012)			0.04%	2.84%	1.50%	0.10%	0.23%	
2012 off take peak (MW excluding embedded generation)			7.09	28.49	50.70	119.85	70.50	
Off take n-1 Capacity (Continuous) MVA			27.00	40.90	66.00	100.00	81.00	
Off take n-1 Capacity (24 hr Winter Post Contingency MVA)			27.00	40.90	80.00	112.00	81.00	
Embedded Generation (2012 MW at time of load peak)			19.41	3.28	1.20	51.56	0.00	
Embedded Generation (2012 MW at time of off take peak)			6.22	3.28	1.20	7.07	0.00	

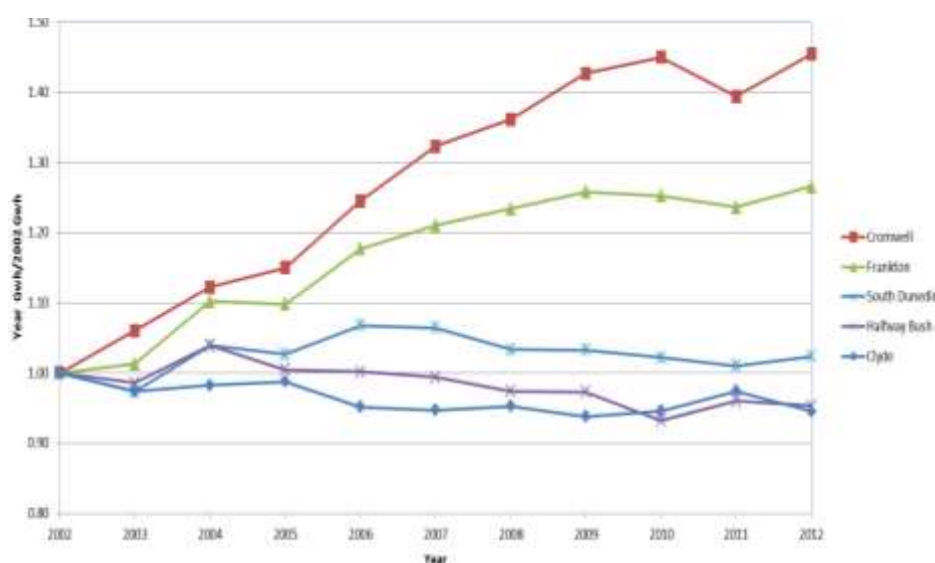


Figure 6.1 – Comparative growth in GXP energy (GWh 2002 normalised)

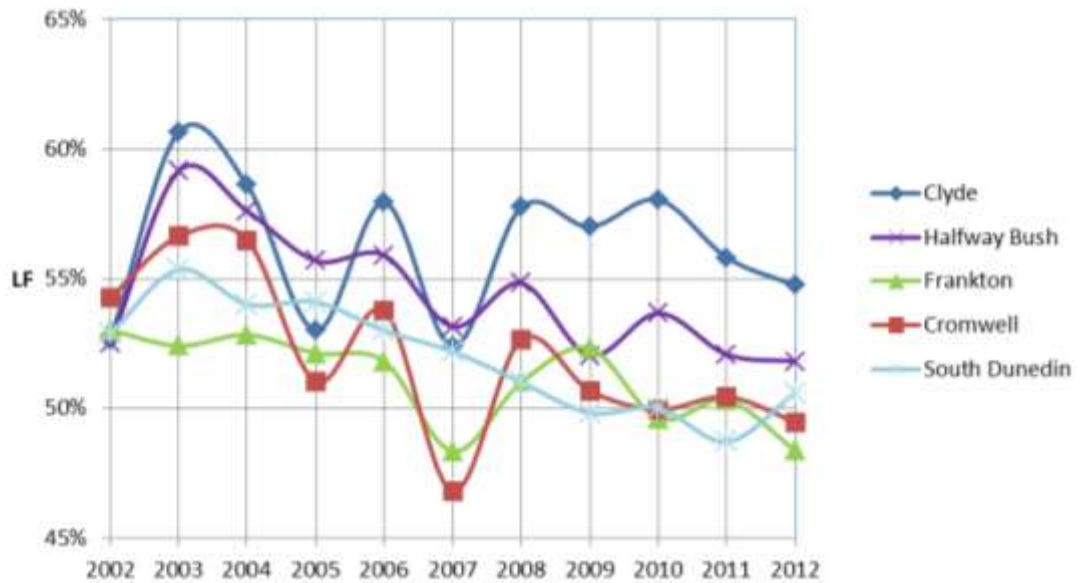


Figure 6.2 – Load factor by GXP

Table 6.9 : Comparison of 2012 actual and predicted loads

GXP	2012 MVA Predicted	2012 MVA Actual	Difference
Clyde	16.6	17.4	4.82%
Cromwell	31.8	31.8	0.00%
Frankton	51.9	51.9	0.00%
Halfway Bush	127.3	128.5	0.94%
Sth Dunedin	73.7	70.5	-4.34%

Historic trends in load for each GXP are illustrated in the following sections and graphs 6.3-6.7 provide a revised load prediction based on the factors discussed in Section 6.4. The comments that follow highlight the main areas being monitored and/or addressed by Aurora.

Clyde

Clyde GXP load prediction is illustrated in Figure 6.3. Peak demand has ranged from 15.6MW - 18.2MW over the last 8 years. Growth has averaged less than 0.5% per year since 2004 and is not expected to accelerate during the planning period unless the Dairy Creek irrigation project proceeds. The distributed generation on this GXP almost meets total demand on the GXP. Should the embedded generation fail the maximum demand on the GXP would be approximately 17 MVA. However as this GXP has two 27MVA transformers it is considered that there is adequate GXP capacity at Clyde for the foreseeable future. The possibility of additional generation will continue to keep the off-take low. Clyde Ripple Injection replacement is planned (see Section 6 – Network Development)

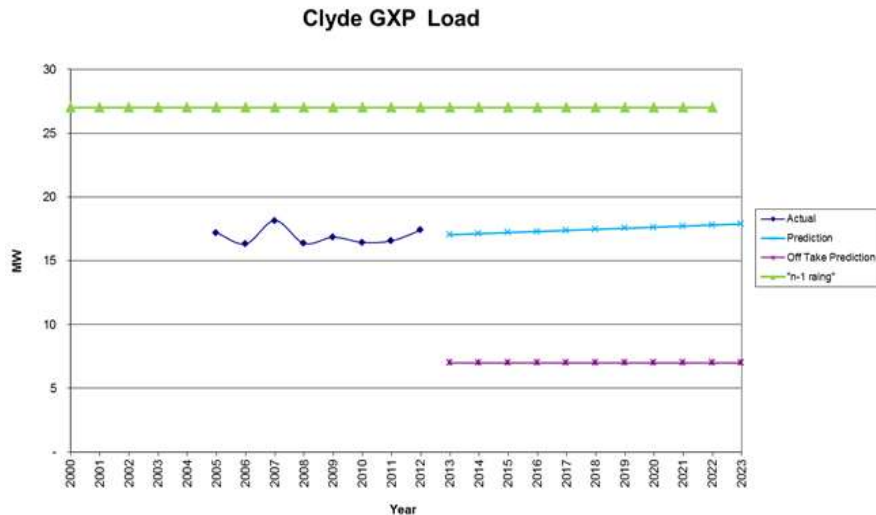


Figure 6.3 - Clyde GXP Actual and Prediction Loads

Cromwell

Cromwell GXP load prediction is illustrated in Figure 6.4. Peak demand has ranged from 21.5MW - 31.8MW over the last 8 years. Although currently under the limit for n-1 of 40.9MW, loads are predicted to continue to increase, exceeding the n-1 rating around 2020, being influenced predominantly by demands for dairy irrigation. Development reports have scoped issues and options (see DR 33, 45 and 160) and Section 6.5 of this AMP also covers the options considered to address this issue. The distributed generation on this GXP is 5.57MW and ripple injection was upgraded in 2009 providing the ability to cope with a connected load in excess of the current 50 MVA firm capacity (as well as the future Hawea generation.) The impact of the Hawea Generation has not been included in the load prediction due to the uncertain nature of this project.

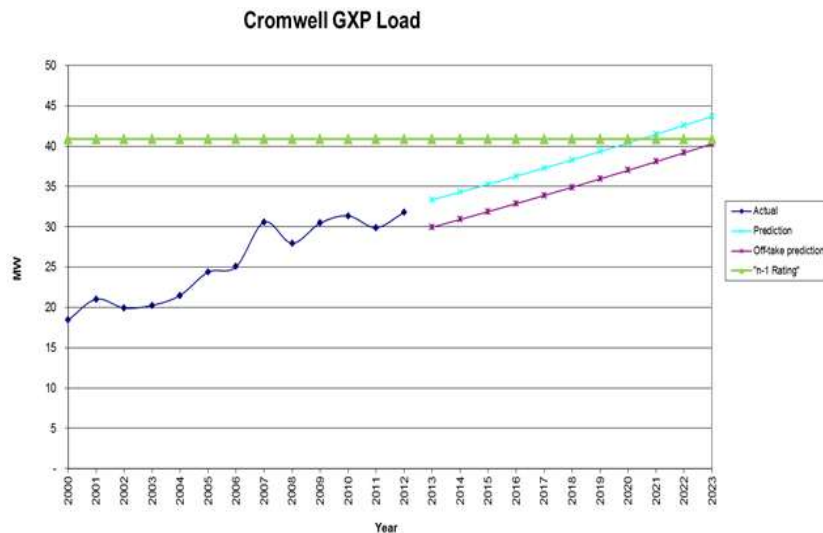


Figure 6.4 - Cromwell GXP Actual and Prediction Loads

Frankton

Frankton GXP load prediction is illustrated in Figure 6.5. Peak demand has ranged from 41.4 MW – 50.1MW over the last 8 years. Past trends indicate a growth rate around 1.5% p.a. The distributed generation on this GXP is 3.96MW. Electricity Southland Ltd (ESL) takes supply from this GXP as well as Aurora. The load predictions include an estimated allowance for the ESL load. It is predicted the 66 MVA continuous n-1 rating at this site will not be exceeded during the planning period as shown in Figure 6.5. In addition, the ripple injection plant at this site was upgraded in 2010 and the new injectors will cope with up to 100 MW of connected load.

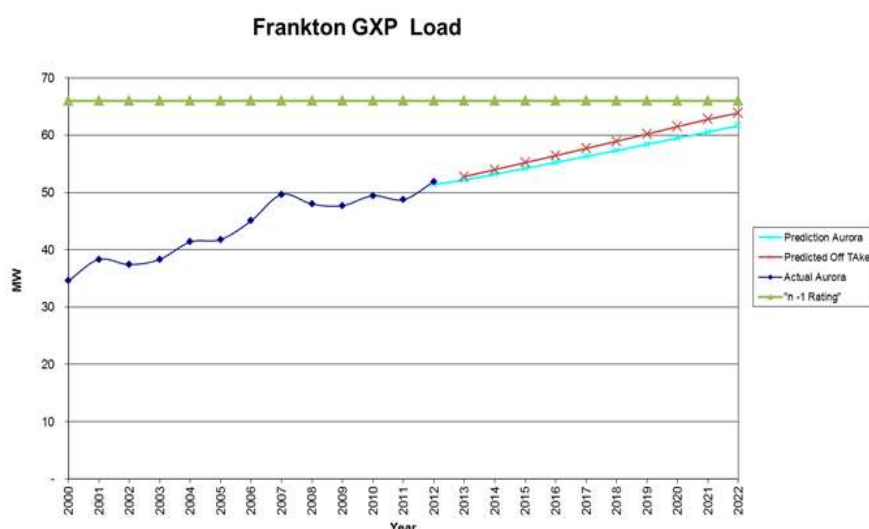


Figure 6.5 - Frankton GXP Actual and Prediction Loads

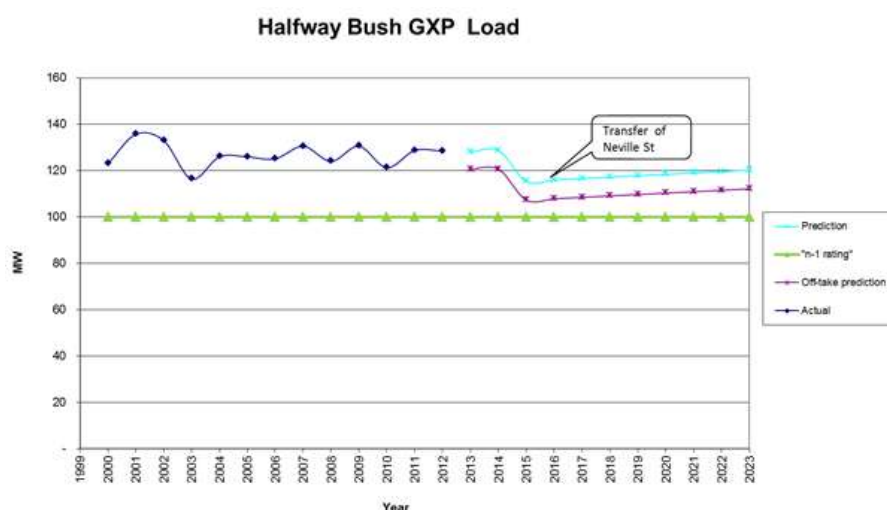


Figure 6.6 – Halfway Bush GXP Actual and Prediction Loads

Halfway Bush

Halfway Bush GXP load prediction is illustrated in Figure 6.6. Peak demand has ranged from 121.3MW – 130.6MW over the last 8 years. The off-take peak at Halfway Bush exceeds the 112 MVA post contingency rating. Past trends indicate a growth rate around 0.1% p.a. The distributed generation on this GXP is 95.8MW. The connection of the 36 MW TrustPower Mahinerangi wind farm occurred during 2011.

Table 6.12 in the following section (6.5.5) indicates the critical nature of this GXP, with a significant majority of priority 1 and 2 customers being supplied by zone substations in this area. Aurora recognises this and has developed a contingency plan - in the event of a failure of the Transpower 100 MVA transformer, TrustPower would be asked to increase its 33 kV generation up to 44 MW during peak period. Also up to 5 MW can be transferred to the South Dunedin GXP via the 6.6 kV network. However, this would still leave a shortfall and the contingency plan also addresses this (see development report DR24), which includes the transfer of the Neville Street substation load to South Dunedin (see below and section 6.5 for related development planning options).

South Dunedin

South Dunedin GXP load prediction is illustrated in Figure 6.7. Peak demand has ranged from 66.1MW-72.2MW over the last 8 years, well under the 81 MVA limit. Past trends indicate a growth rate around 0.23% p.a. and over the forward 10yr planning period is expected remain relatively static, with the main impact on demand being through the transfer of Neville Street Substation from Halfway Bush to South Dunedin in 2015. While under the current network configuration there is adequate GXP capacity, with two 100 MVA transformers, it must be noted

here that these have been assigned an 81 MVA limit by Transpower, due to metering accuracy limitations, so the load is therefore expected to exceed this 81 MVA limit unless the limitations are lifted.

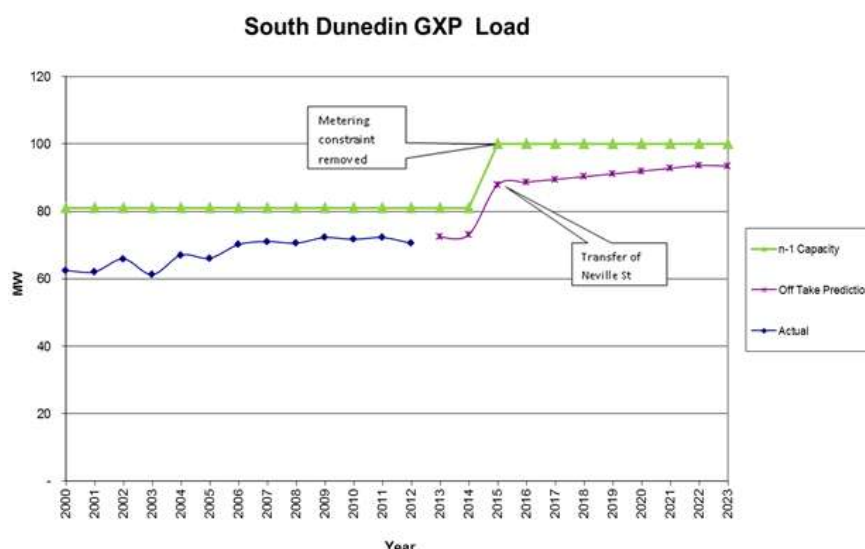


Figure 6.7 – South Dunedin GXP Actual and Prediction Loads

6.5.2 Maximum Coincident System Demand

The term Maximum Coincident System Demand means that the forecast values are the summation of the off-take at each of the 5 GXPs serving the Aurora network, plus the contributed output of all distributed generation connected at high voltage, at a single point in time (i.e., 1 of 17,520 half-hours). GXP off-take is largely dependent on weather, and may GXPs differently; for example, Central Otago versus Dunedin. Similarly, generation output depends largely on water availability (61%) and wind conditions (29%). Historical analysis suggests that coincident values have very little inherent predictability. The table below summarises the forecast. It should be noted that there is very little certainty in conducting such a forecast.

	2013	2014	2015	2016	2017	2018
Maximum Coincident System Demand (MW)	276	293	287	281	281	281

6.5.3 Subtransmission

Aurora's subtransmission network comprises various configurations (see Section 5.2). Graphs 6.8 - 6.12 illustrate historic trends in load for the subtransmission network and provide a revised load prediction based on the factors discussed in Sections 6.3 and 6.5. The comments highlight the main areas being monitored and/or addressed by Aurora where it is considered that capacity is a concern. For the Central network, these are listed below:

- Alexandra-to-Roxburgh subtransmission
- Clyde-to-Alexandra subtransmission
- Wanaka 33KV subtransmission
- Upper Clutha subtransmission
- Frankton-to-Queesntown
- Wakatipu Basin 33KV Ring

Where constraints are expected, the associated upgrades are discussed in the network development plan (Section 6.6).

The content of this section is structured by GXP area and begins with the subtransmission network in Clyde, Cromwell, Frankton followed by the Halfway Bush and South Dunedin networks.

Clyde

Alexandra to Roxburgh Subtransmission

There are two 33 kV lines between Roxburgh and Alexandra. These lines consist of both Dog and Jaguar conductor. The maximum load on these lines is driven by generation. With the commissioning of the Pioneer wind turbines at Horseshoe Bend (1.2MW), the Talla Burn (1.9 MW) and Kowhai (2 MW) generation there may be times when the total load being carried on these lines will exceed the summer rating of a single circuit Dog line (226A, 12.9 MVA). This constraint is managed by requesting a reduction in generation output, if necessary, when one line is out of service.

There is now no capacity for additional generation to be connected to the Roxburgh 33 kV bus due to the operating voltage being at the maximum Aurora's zone substations in the area can tolerate.

Clyde to Alexandra Subtransmission

The Clyde to Alexandra lines have Dog conductor which provide a summer/winter n-1 capacity of 21/13 MVA which is adequate for loads expected within the planning period.

Cromwell

Wanaka 33 kV subtransmission

The Wanaka 33 kV subtransmission supplies Cardrona and Maungawera substations. The maximum n-1 rating of the 33 kV supply is 6 MVA if the 11kV is fully loaded.

At present, the Cardrona and Maungawera substations are supplied from the Wanaka 33 kV bus. The 2012 peak load was 4.5 MVA. It is not expected the 33 kV supply will become constrained within the planning period due to the plan to transfer the Cardrona substation load from 33 kV to 66 kV assuming the Riverbank Road substation is constructed.

Upper Clutha subtransmission

Figure 6.8 illustrates a single line diagram of the existing subtransmission system and Figure 6.9 illustrates the load predictions for the Upper Clutha, which is supplied from the Transpower Cromwell GXP at 66 kV and feeds Queensberry. The Queensberry transformer is connected to one of the two 66 kV lines, but can be connected to either.

The 66 kV lines from Cromwell to Wanaka have Dog conductor with summer/winter ratings of 266/374 Amps. The Cardrona line is insulated for 66 kV operation but is currently operating at 33 kV. The Cardrona transformer is a dual ratio 66-33 kV unit that is currently operating at 33 kV.

The n-1 capacity of the existing Upper Clutha 66 kV network has the following constraints:

- ability to maintain 11 kV target volts in the Wanaka area;
- rating of Cromwell 33/66 kV auto transformers;
- rating of the 66 kV Dog conductor;
- firm 33 kV capacity at the Cromwell GXP.

Works that will reduce these constraints are presented in Section 6.6. Note, however, that another review of the future options for this area is being carried out in 2013/14.

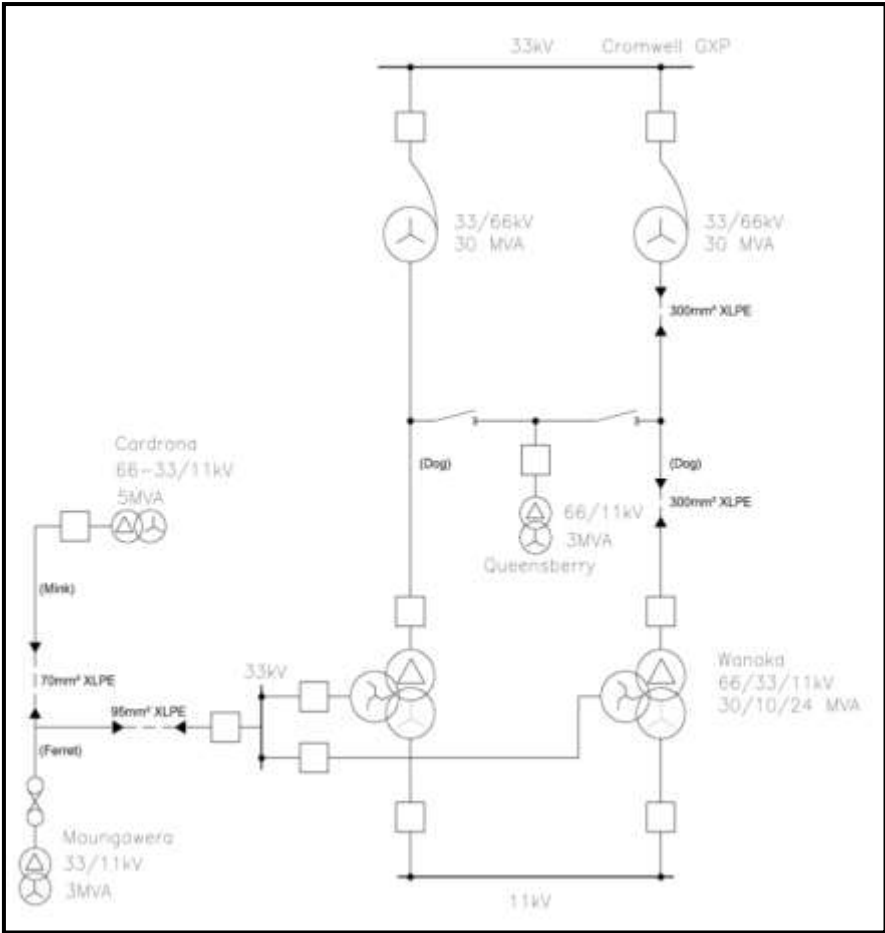


Figure 6.8 - Single line diagram of existing Upper Clutha subtransmission

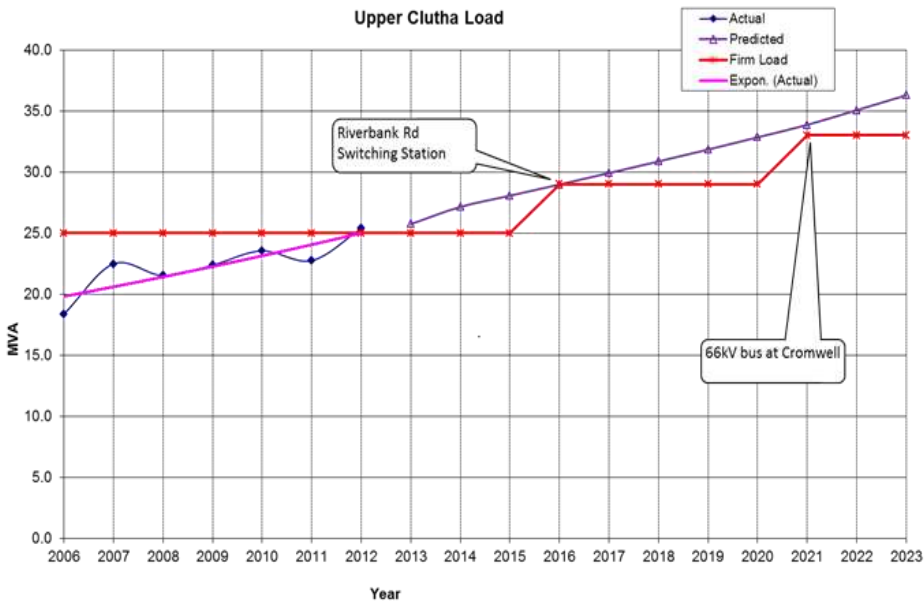


Figure 6.9 - Upper Clutha subtransmission

West Wanaka and Treble Cone

The Treble Cone ski field has proposed to install a gondola that would require an all-year capacity of 1 MW. This project is in abeyance but other development proposals in the area could increase the load on the Wanaka 11 kV feeder 2754 beyond its ability to maintain statutory voltage limits. When this occurs, it is proposed to extend the 33 kV subtransmission toward Treble Cone and install the appropriate 33/11 kV zone substations.

A report has been prepared (see DR23) looking at various configuration options. No work has been scheduled due to the uncertain nature of the load growth in the area. However, when poles are replaced between Wanaka and Glendhu Bay they will be fitted with 33 kV cross arms and insulators to facilitate a conversion to 33 kV.

Cardrona Valley Subtransmission

A subtransmission line to the new (5MVA) Cardrona substation was commissioned in 2011. It currently operates at 33 kV and will be upgraded to 66 kV when the Riverbank Road switching station is installed. The line will have a capacity in excess of 30 MVA when operating at 66 kV.

Frankton

Frankton to Queenstown

The Frankton to Queenstown subtransmission consists of three parallel circuits with Dog conductor and cables at the ends. The n-1 capacity of this network is 40 MVA and this load is not predicted to be reached within the 10-year planning period as shown in Figure 6.10. When the subtransmission n-1 capacity is reached, it is currently considered that the most economic option to increase the delivery capacity to Queenstown, is to install a third transformer at the Queenstown substation (15 MVA) and provide additional 33 kV transmission capacity to the Commonage substation.

Wakatipu Basin 33 kV Ring

Figure 6.11 illustrates the load predictions for the Wakatipu Basin 33 kV ring, which supplies the Dalefield, Arrowtown, Coronet Peak and Remarkables substations and is run open at Arrowtown. The present and predicted peak loads on the ring were derived by combining the loads of the substations on the ring and applying a 0.87 diversity factor.

The ring has a capacity of 22 MVA with all circuits in service. The ring load exceeded its n-1 capacity during the winter of 2012 and Figure 6.11 indicates that it did. The timing of snow making at Coronet peak has a significant effect on the diversity which varies from year to year. See Section 6 for options to address this issue.

The Arrowtown peak load is currently predicted to exceed the rating limit of 9.7 MVA in 2021. The present n-1 capacity of the ring is 13 MVA with the constraint being the winter rating of Ferret conductor.

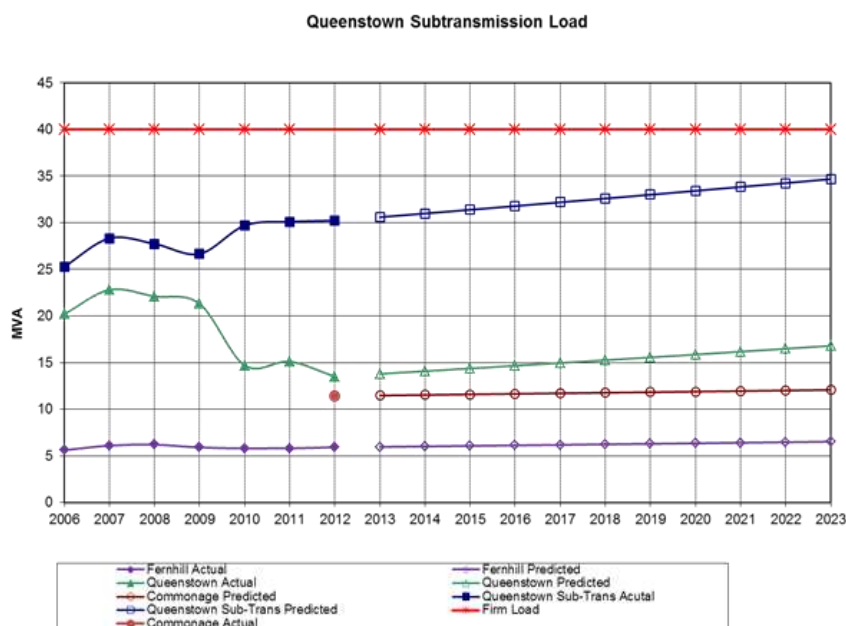


Figure 6.10 - Frankton to Queenstown subtransmission

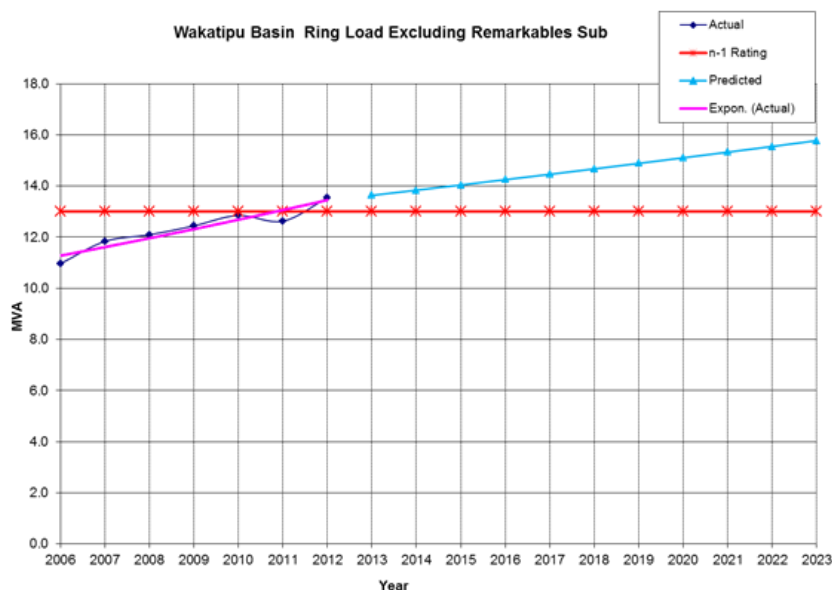


Figure 6.11 - Wakatipu Basin Subtransmission 33 kV Ring

Glenorchy Subtransmission

Glenorchy is presently supplied from Queenstown 11 kV Feeder 5202. This is the only line supplying the Glenorchy area; there is presently no back-feed to this area if there is an outage event on this part of the network. The line was built for 33 kV operation in anticipation of future conversion. When converted to 33 kV, it will be supplied from the Fernhill substation where a 33 kV circuit breaker has already been installed for this purpose.

The peak load on QT5202 occurs when the Oxburn power station (400 kW) is out of service. Oxburn is a run-of-the-river station that normally operates continuously but is required to shut down during high rainfall events due to excessive gravel entering the river. The Oxburn power station is not able to run islanded and trips off line whenever there is a fault on QT5202.

In previous development plans, load predictions used maximum demands on QT5202; however, this did not give the total picture of the area load due to the effect of the Oxburn generator.

A review of the load prediction as carried out in 2011, which indicated that that it will not be possible to maintain the feeder voltage above design values after the winter of 2014. Options to upgrade are discussed in Section 6.

Halfway Bush

Taieri Subtransmission

The "A" and "B" lines are rated at 300/370 Amps (summer/ winter) while the "C" line is rated at 440/540 Amps. The loss of Fisher & Paykel load means that now under an 'n-2' contingency situation resulting in the loss of "C" line and no generation available from Waipori, the load can still be supplied via "A" and "B" lines.

Since the installation of 36 MW of wind generation by TrustPower it now has more generation than the lines can cope with. TrustPower manages the mix of hydro and wind generation to ensure the rating of the lines are not exceeded. TrustPower is installing a "run back" scheme to avoid the overloading of lines remaining in service should one of the three lines trip during high load times.

Mosgiel Laterals

The Mosgiel No 3 lateral is only rated at 360 Amps (20 MVA). The other laterals are rated in excess of 500 Amps. The 360 Amp rating means that should the lateral be required to carry the combined Mosgiel and East Taieri loads, its rating could be exceeded. At present, the Lateral 3 constraint could be avoided by dedicating Lateral 3 to supply East Taieri, Lateral 2 to supply Mosgiel thus making Lateral 1 the standby lateral.

This project would require some strung bus modifications at Mosgiel plus protection and control modifications. Further investigation is required to determine if this project is economic.

Port Chalmers Subtransmission

The lines to Port Chalmers supply both North East Valley and Port Chalmers substations. The n-1 capacity of these circuits is 27 MVA which is well above loads predicted for the planning period.

6.5.4 Zone Substation Demand Projections

Aurora's network contains 36 zone substations, 18 in Dunedin and 18 in Central Otago. Table 6.9 provides actual figures on historical and predicted demands for all zone substations.

Predicted future demands are shown with a shaded background when they exceed the firm capacity of the substation and this act as a "flag" for closer study. When new substations are commissioned it results in a reduction in load of the substation that is presently supplying the load. This is taken into account in future demand predictions. Zone substations with a capacity of 5 MVA or less are not designed with n-1 security. The mobile substation or spare transformers provide cover.

The n-1 capacity is the maximum load a substation can supply in the event of the failure of any one item of substation equipment without the need to transfer any load from the substation.

The firm capacity is the maximum load a substation can carry with the largest transformer out of service and up to 6 MVA of load transfer to adjacent substations.

It will generally take at least an hour to transfer load from the zone substation. During this hour, the in service transformer and associated equipment must be capable of carrying the allocated firm capacity. Where the load limitation is HV switchgear that has no overload capability the firm load can be restricted to the same as the n-1 load.

It is current practice for Aurora to take some risk and allow loads to exceed the n-1 capacity for a short time before upgrades are completed.

Aurora Energy Asset Management Plan 2013 - 2023

				Historical Loads MVA								Exp Growth Calc		Linear Trend Calc			Predictions			Predicted Demands Between Exp and Linear MVA												
Zone Substation	Transformer MVA	Firm Load MVA	n-1	2006	2007	2008	2009	2010	2011	2012	2012	2013	Previous Growth (Exp) %/yr	2012	2013	Previous Growth (Lin) MVA/yr	Exponential Growth %/yr	Linear Growth MVA/yr	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023			
Alexandra	7.5/15+7.5/15	15	15	10.9	12.4	11.4	11.9	11.6	10.9	11.7	11.5	11.5	-0.06%	11.5	11.5	-0.01	0.4%	0.04	11.6	11.6	11.6	11.7	11.7	11.8	11.8	11.9	11.9	12.0	12.0			
Anderson's Bay	15 + 15	18	18	14.9	16.6	15.7	17.1	15.3	16.0	15.4	15.8	15.8	-0.01%	15.8	15.8	0.00	1.0%	0.16	16.0	16.2	16.3	16.5	16.6	16.8	17.0	17.1	17.3	17.5	17.6			
Arrowtown	5 + 5	7.5	6	7.2	7.7	7.3	7.6	7.9	7.6	8.3	8.0	8.2	1.69%	8.0	8.2	0.13	2.0%	0.15	8.2	8.4	8.5	8.7	8.8	9.0	9.2	9.3	9.5	9.7	9.8			
Berwick	3	3.6	0	1.1	1.2	1.3	1.2	1.3	1.3	1.3	1.3	1.4	2.47%	1.3	1.4	0.03	2.0%	0.03	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.6	1.6			
Clyde/Earnsclough	4 +2	4.8	4	3.7	4.0	4.1	4.1	4.1	3.8	3.8	3.9	3.9	-0.04%	3.9	3.9	0.00	1.0%	0.04	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4			
Coronet Peak	5	6	0	3.6	3.6	4.5	4.6	4.6	4.6	4.6	4.9	5.1	4.46%	4.8	5.0	0.18	0.0%	0.00	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8			
Corstorphine	12/24 + 12/24	23	23	12.8	13.8	12.5	14.3	13.2	13.8	13.1	13.5	13.6	0.48%	13.6	13.6	0.06	0.0%	0.00	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5			
Cromwell	5/10 + 7.5	9.0	9.0	7.9	9.2	9.2	9.8	10.0	9.4	9.7	10.1	10.3	2.69%	10.0	10.3	0.24	4.0%	0.04	10.3	10.5	10.7	11.0	11.2	11.5	11.8	12.1	12.3	12.7	13.0			
Dalefield	3	3.6	0	1.8	2.3	2.1	2.1	2.3	2.3	2.7	2.6	2.7	4.88%	2.6	2.7	0.11	3.0%	0.07	2.6	2.7	2.8	2.9	2.9	3.0	3.1	3.2	3.3	3.4	3.4			
Earnsclough	2	Used to increase Clyde/Earnsclough firm capacity to 4.8MVA																		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
East Taieri	12/24 + 12/24	24	18.5	15.7	15.7	15.5	16.7	15.8	16.2	16.5	16.4	16.6	0.83%	16.4	16.5	0.13	1.0%	0.16	16.6	16.7	16.9	17.1	17.2	17.4	17.6	17.7	17.9	18.1	18.2			
Etrick	3	3.6	0	1.5	2.0	1.8	2.1	2.0	1.7	2.0	2.0	2.0	2.05%	2.0	2.0	0.03	0.5%	0.01	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1			
Frankton	12/24 + 7.5/15	17	15	10.4	12.0	13.2	13.9	12.1	10.5	13.3	12.6	12.8	1.39%	12.7	12.9	0.17	3.0%	0.35	13.7	14.1	14.5	14.9	15.3	15.7	16.1	16.5	14.9	15.3	15.8			
Fernhill	7.5/10+7.5/10	10	10	5.6	6.1	6.2	5.9	5.8	5.8	5.9	5.9	5.9	0.01%	5.9	5.9	0.00	1.0%	0.05	6.0	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.5	6.5			
Green Island	15 + 15	18	18	14.0	14.2	13.8	13.7	13.4	14.0	13.7	13.6	13.6	-0.44%	13.6	13.6	-0.06	0.0%	0.00	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6			
Halfway Bush	15 + 15	18	18	13.6	14.2	13.8	14.5	14.6	14.8	14.6	14.8	15.0	1.28%	14.8	15.0	0.18	1.5%	0.23	15.1	15.3	15.5	15.8	16.0	16.2	16.4	16.7	16.9	17.2	17.4			
Kaikorai Val.	12/24 + 12/24	23	22	10.3	10.4	9.9	10.2	9.2	9.3	10.7	9.8	9.7	-0.63%	9.8	9.8	-0.06	0.0%	0.00	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8			
Maungawera/Hawea	3	3.6	0	2.5	3.2	2.1	2.2	2.3	2.3	2.6	2.5	2.7	4.89%	2.5	2.7	0.12	1.8%	0.05	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1			
Mosgiel	10 + 10	14	12	12.2	12.0	12.0	9.3	7.6	7.8	8.0	8.0	8.2	2.18%	8.0	8.1	0.17	2.0%	0.16	8.1	8.3	8.5	8.6	8.8	9.0	9.1	9.3	9.5	9.6	9.8			
Neville St	15 + 15	18	18	14.4	14.9	13.3	14.8	13.4	13.6	13.6	13.5	13.3	-1.21%	13.5	13.3	-0.17	0.0%	0.00	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5			
North City	14/28 +14/28	28	28	20.2	20.7	20.7	19.7	19.0	20.0	18.9	19.1	18.9	-1.28%	19.1	18.8	-0.26	0.0%	0.00	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1			
North East Val.	9/18 +12/18	23	18	10.8	11.0	10.9	11.8	11.2	11.8	11.0	11.5	11.6	0.81%	11.5	11.6	0.09	1.0%	0.12	11.6	11.7	11.8	11.9	12.1	12.2	12.3	12.4	12.5	12.7	12.8			
Omakau	3	3.6	0	1.6	1.8	1.8	2.0	2.1	2.0	1.9	2.1	2.1	3.31%	2.1	2.1	0.06	4.0%	0.09	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.9	3.0	3.1			
Outram	3 + 3	5.6	3.6	2.9	2.8	2.7	2.8	2.9	3.0	2.9	2.9	3.0	0.87%	2.9	3.0	0.02	1.0%	0.03	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.3			
Port Chalmers	7.5 + 7.5	10	9	7.9	8.3	7.5	7.9	7.5	7.5	7.5	7.4	7.3	-1.34%	7.4	7.3	-0.11	0.0%	0.00	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4			
Queensberry	3	3.3	0	1.9	1.7	1.8	1.4	2.4	2.3	2.5	2.4	2.5	6.23%	2.4	2.5	0.13	4.0%	0.10	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.5	3.6	3.7			
Queenstown	10/20 +10/20	26	20	20.2	22.8	22.1	21.3	14.7	15.1	13.5	13.8	13.2	-4.15%	13.5	11.9	-1.59	2.0%	0.30	13.8	14.1	14.4	14.7	15.0	15.3	15.6	15.9	16.2	16.5	16.8			
Remarkables	3	3.6	0	0.8	0.8	0.8	0.8	0.8	1.0	1.2	1.0	1.1	5.87%	1.0	1.1	0.05	Manual Prediction		2.0	2.6	3.4	3.5	3.5	4.8	4.8	4.8	4.8	4.8	4.8			
Roxburgh	1.5 +1.5	3.6	1.8	2.3	2.5	2.2	2.8	2.8	2.3	2.3	2.4	2.4	-0.01%	2.4	2.4	0.00	1.0%	0.02	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7			
Smith St	15 + 15	18	18	16.5	16.9	16.1	16.8	15.8	16.9	16.7	16.5	16.6	0.06%	16.6	16.6	0.01	1.0%	0.17	16.7	16.9	17.1	17.2	17.4	17.6	17.7	17.9	18.1	18.3	18.4			
South City	9/18 +9/18	18	18	15.4	15.7	15.3	15.8	15.0	15.2	15.0	15.1	15.0	-0.58%	15.1	15.0	-0.09	0.5%	0.07	15.2	15.2	15.3	15.4	15.4	15.5	15.6	15.7	15.7	15.8	15.9			
St Kilda	12/24 + 12/24	23	23	15.4	16.3	15.6	15.7	15.3	15.5	15.3	15.4	15.3	-0.47%	15.4	15.3	-0.07	0.0%	-0.07	15.3	15.3	15.3	15.2	15.2	15.2	15.1	15.1	15.0	15.0	15.0			
Wanaka	12/24 +12/24	24	24	15.1	18.6	18.7	19.6	20.3	17.6	19.2	19.8	20.3	2.48%	19.7	20.1	0.42	4.0%	0.70	20.5	21.2	22.0	22.8	23.6	24.5	25.3	26.2	19.1	19.8	20.6			
Ward St	12/24 +12/24	24	24	11.6	11.3	11.4	12.5	11.9	14.3	14.2	14.0	14.6	4.11%	14.0	14.5	0.51	1.0%	0.14	14.1	14.3	14.4	14.6	14.7	14.8	15.0	15.1	15.3	15.4	15.6			
Willowbank	15 + 15	18	18	12.8	12.7	12.5	13.7	12.2	13.2	12.1	12.6	12.5	-0.39%	12.6	12.6	-0.05	0.0%	0.00	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6			
Commonage	14/17 +14/17	23	17	0	0	0	0	9.8	9.8	11.4	11.1	12.0	7.91%	11.2	13.5	2.27	0.5%	0.06	11.5	11.5	11.6	11.6	11.7	11.8	11.8	11.9	11.9	12.0	12.1			
Cardrona	5	5	0	0	0	0	0	0	1.9	3.1	3.1	3.1		2.1	2.6	0.47	2.0%	0.05	2.0	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9			
Jacks Point *		10	0																						0.0	0.0	2.0	2.0	2.0			
Riverbank Rd		24	24														4.0%	0.32								0.0	8.0	8.3	8.6			
MG + ET (Merged 1/2hr data)		30.8	30.8	26.0	27.3	26.5	26.5	23.5	23.1	22.8	22.2	22.2	0.00%	22.0	20.9	-1.12	0.0%	0.0	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.2			
* Jacks Point actual load is included in Frankton																										23.1	23.1	23.1	23.2			

* Jacks Point actual load is included in Frankton

Table 6.10 – Zone substation historical and predicted demands

The following section provides graphs and comments on demand projections for the zone substations considered a priority. Note that the section is structured by GXP area and begins with the zone substations in Clyde, Cromwell, Frankton followed by the zone substations in Halfway Bush and South Dunedin. Projects to address related issues are discussed in Section 6.6.

Clyde

Alexandra Substation

It was previously proposed that a second substation would be established to help eliminate future HV feeder off-loading constraints and provide a more secure supply to the Alexandra area. The Alexandra zone substation is now predicted remain within its firm load rating beyond the planning period.

No other significant demand-related issues foreseen for substations located in this GXP area within the 10 year planning period.

Cromwell

Cromwell Zone Substation

Figure 6.12 illustrates the load predictions for Cromwell zone substation. The load on Cromwell is growing and the peak demand now exceeds its 9 MVA firm capacity. The 5 MVA mobile substation is being used to provide n-1 cover. In the 2011-21 AMP it was proposed the transformers be upgraded prior to the 2015 winter when it was predicted the load would reach 12 MVA. Present load predictions have reduced, with the 12 MVA limit now predicted for the winter of 2018. In the 2012 AMP, it was recommended that a May 2015 commissioning date be retained, however this has been revised and is now proposed to be deferred to 2016/17. There is still the associated risk of the mobile substation providing cover for this site, in addition to 10 other sites so there is increased potential the mobile will not be available when required.

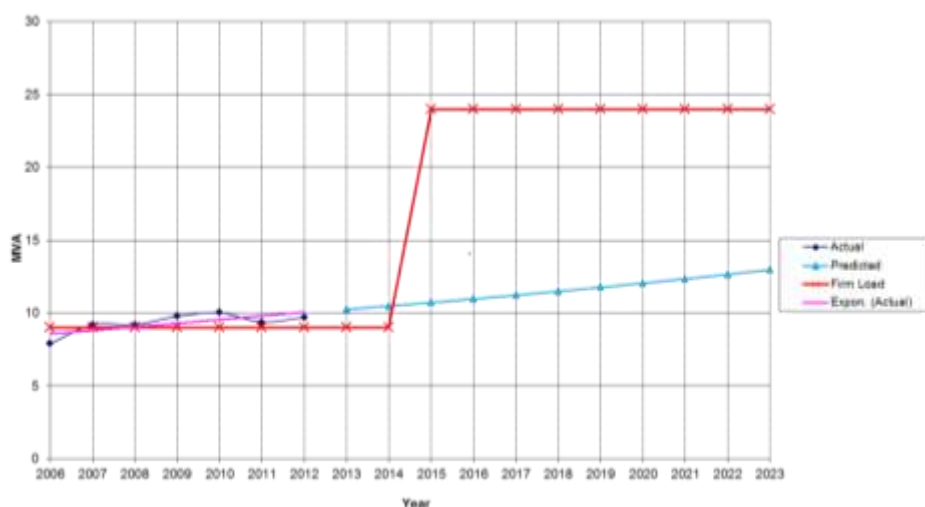


Figure 6.12 – Cromwell Zone Substation Load prediction

Queensberry Zone Substation

Figure 6.13 illustrates the load predictions for Queensberry zone substation. There has been strong growth in load on the Queensberry substation due to irrigation load. There has been considerable variability in the peak loading from year to year. The substation load peaks in the summer. The 2012 peak load was 2.5 MVA. The Upper Clutha load has a relatively low load factor with the highest peaks only occurring for the few hours each year. The Queensberry transformer is a 3 MVA ONAN unit and it is assumed it can be overloaded by 10% during the summer to 3.3 MVA¹¹. Present predictions are for the load to exceed 3.3 MVA during the summer of 2020. The transformer rating can be increased to 4.4 MVA by the addition of fans. If the Tarras irrigation project

¹¹ A 20% overload is considered acceptable for winter conditions

proceeds and the new Maori Point Road substation established, the Queensberry substation could be removed; however, Aurora is currently re-assessing options for this part of the network.

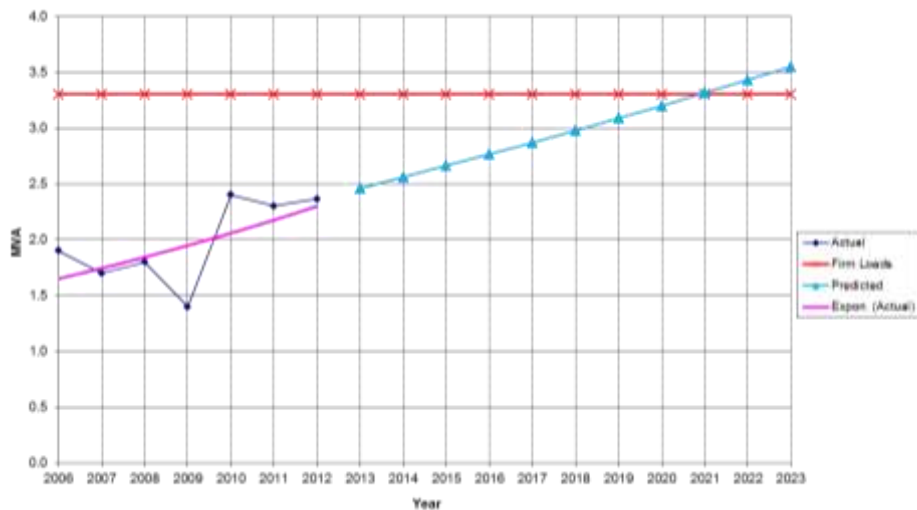


Figure 6.13 – Queensberry Zone Substation Load prediction

Wanaka Zone Substation

Figure 6.14 illustrates the load predictions for Wanaka zone substation. Load growth on the Wanaka zone substation has been significant in the recent past (9.3% annually from 2003 to 2009). It is now predicted the growth will be significantly lower than historical values. Construction of Riverbank Road substation will increase the ability to off-load Wanaka.

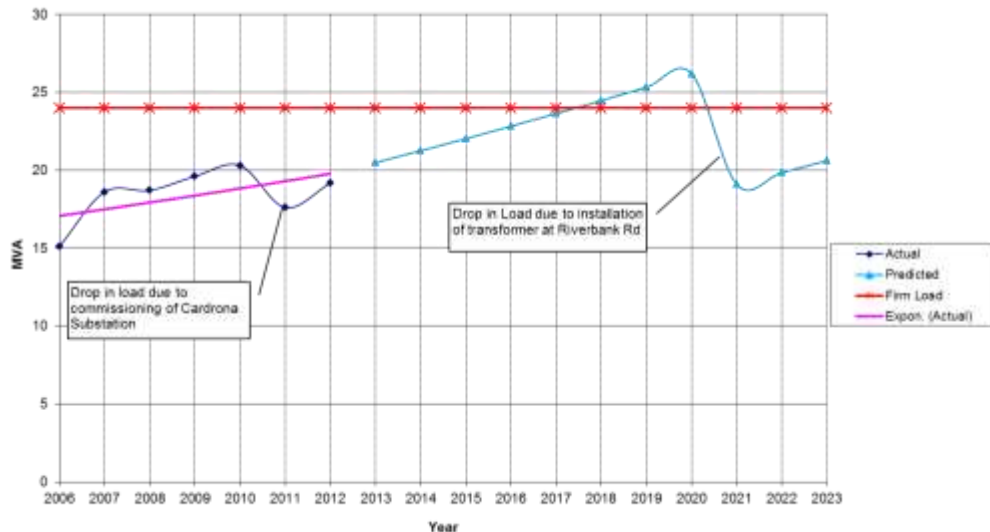


Figure 6.14 – Wanaka Zone Substation Load prediction

Maungawera Zone Substation

The predicted loading (based on calculations done in 2011) on Maungawera is shown in Figure 6.15 which indicates an upgrade is required prior to the summer of 2014. Development report DR126 contains detailed analysis and recommendations, although a review of the predicted loadings and options to address constraints is being carried out in 2013/14.

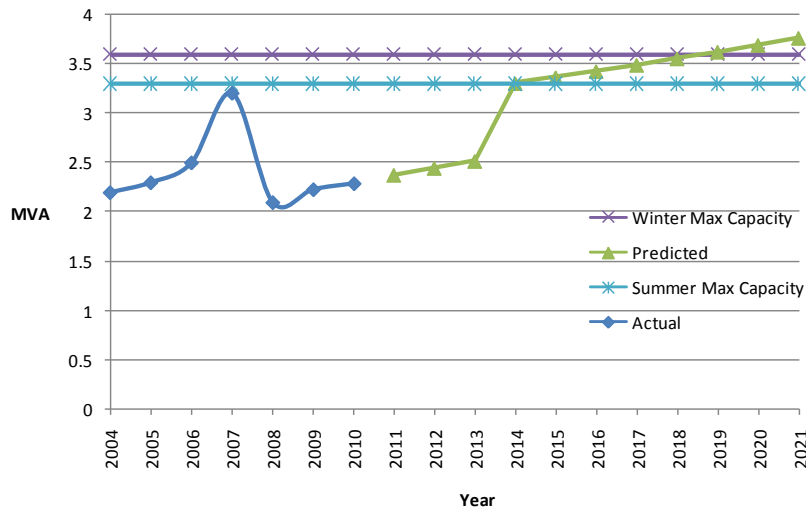


Figure 6.15 – Maungawera Zone Substation Load prediction

Frankton

Arrowtown Zone Substation

Figure 6.16 illustrates the load predictions for Arrowtown zone substation. The Arrowtown substation demand during the 2012 winter was 8.3 MVA which exceeded its firm rating of 7.5 MVA. The firm rating is on the basis of loading one transformer to 120% (6 MVA) and transferring 1.5 MVA to the Coronet substation via feeder AT7692. In 2009, the 3 MVA spare transformer was located at Arrowtown to provide cover in the event of one of the 5 MVA units failing. This transformer has been moved to the Remarkables substation to cater for additional demand at the Remarkables ski field. A parking bay for the 5 MVA mobile substation was established prior to the 2012 winter. The mobile substation can provide cover for a transformer outage up to a load of 10 MVA. The load is not predicted to reach 10 MVA during the planning period. Now that the mobile substation is covering 11 sites however there is increasing risk that it will not be available when required. Options to address this are discussed in section 6.5

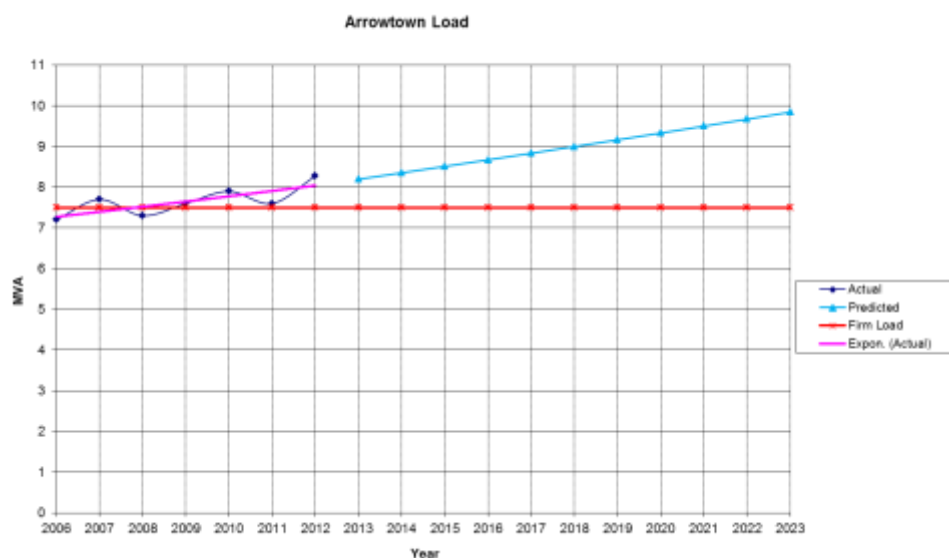


Figure 6.16 - Arrowtown Zone Substation Load prediction

Frankton Zone Substation

Figure 6.17 illustrates the load predictions for Frankton zone substation. The Jacks Point development has an ultimate capacity of 2,700 lots that will have a demand of the order of 8 to 10 MW. A growth rate of 100 kVA per year has previously been the assumed rate until 2016 (which is equivalent to approximately 30 houses) with the rate then increasing to 150 kVA a year. This prediction requires the substation to be installed prior to the winter of 2022. However, the uptake of lots has been slow to date, although there is anecdotal evidence of this beginning to pick-up again. A review of the assumed growth rate will be carried out in 2013/14, with appropriate adjustments made to the assumptions for timing of the proposed substation. Construction of Jacks Point will increase the ability to off load Frankton.

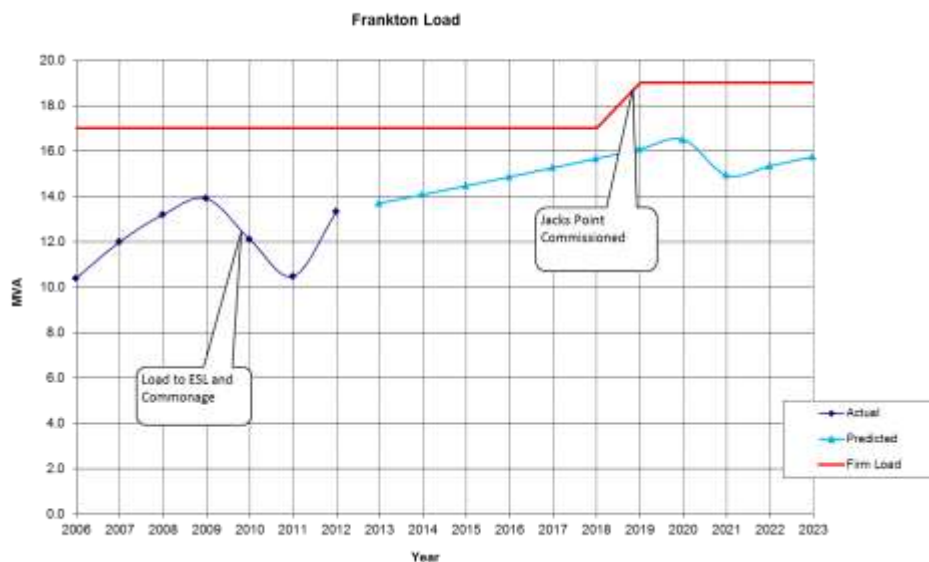


Figure 6.17 - Frankton Zone Substation Load prediction

Remarkables Substation

Figure 6.16 illustrates the load predictions for Remarkables zone substation. The Remarkables ski field has a four stage upgrade planned. Stage one is scheduled to be completed for the winter of 2013 and will increase the field maximum demand to approximately 2 MVA. Stage 2 will add an extra 200 kW (see Figure 6.18).

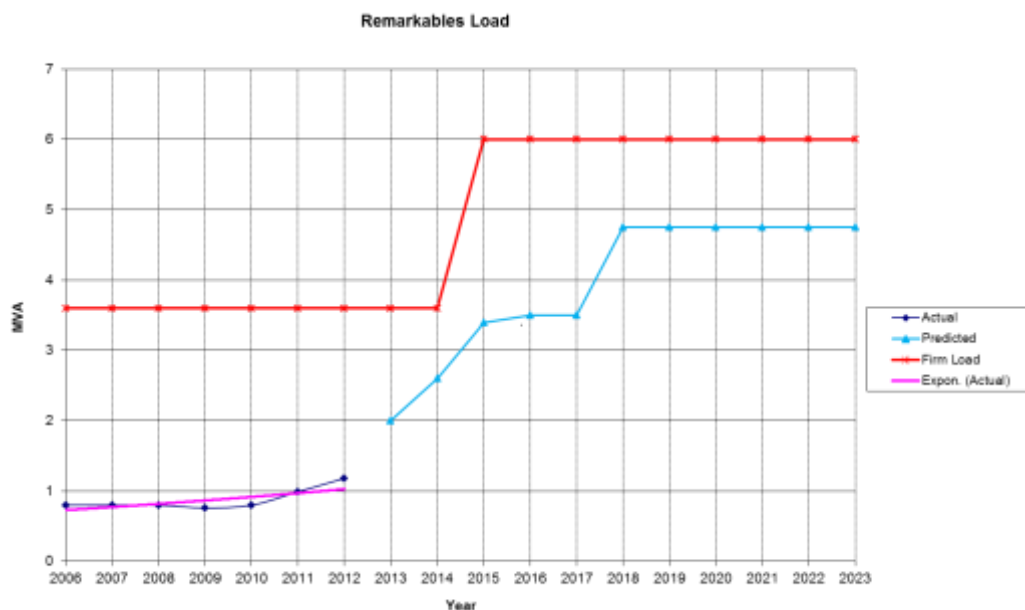


Figure 6.18 - Remarkables Zone Substation Load prediction

Halfway Bush

Smith Street Zone Substation

Figure 6.19 illustrates the load predictions for Smith Street zone substation. Smith Street load is currently predicted to reach its firm rating prior to the 2021 winter. Load was transferred from Smith Street to South City in 2005, to keep the demand on Smith Street below its firm rating which is determined by the capacity of the incoming circuit breakers. It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2020.

Neville Street Zone Substation

It is planned to move the Neville Street substation load to the South Dunedin GXP by May 2015 when the Neville Street substation and gas cables are upgraded, see Section 6.6.

Halfway Bush

Figure 6.20 illustrated the load predictions for halfway Bush zone substation and shows that there are no issues short-term.

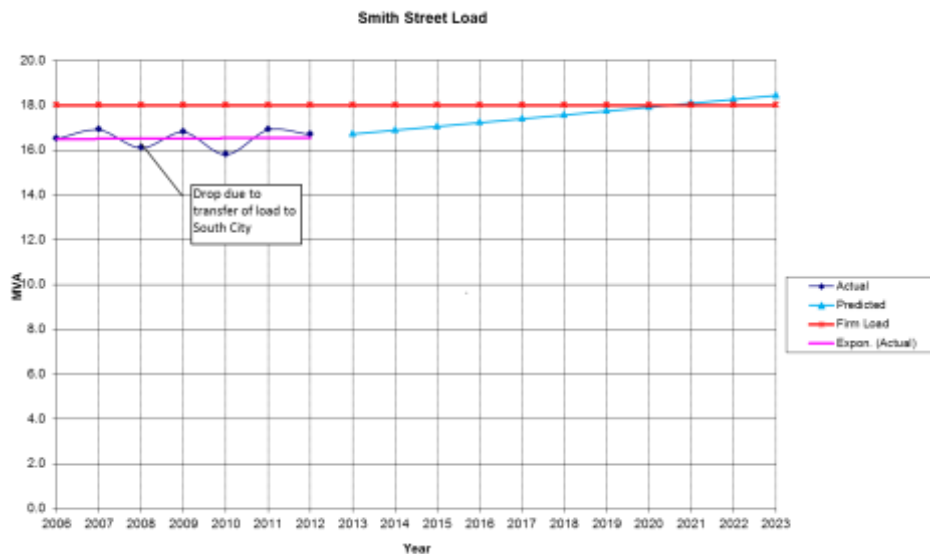


Figure 6.19 – Smith Street Zone Substation Load prediction

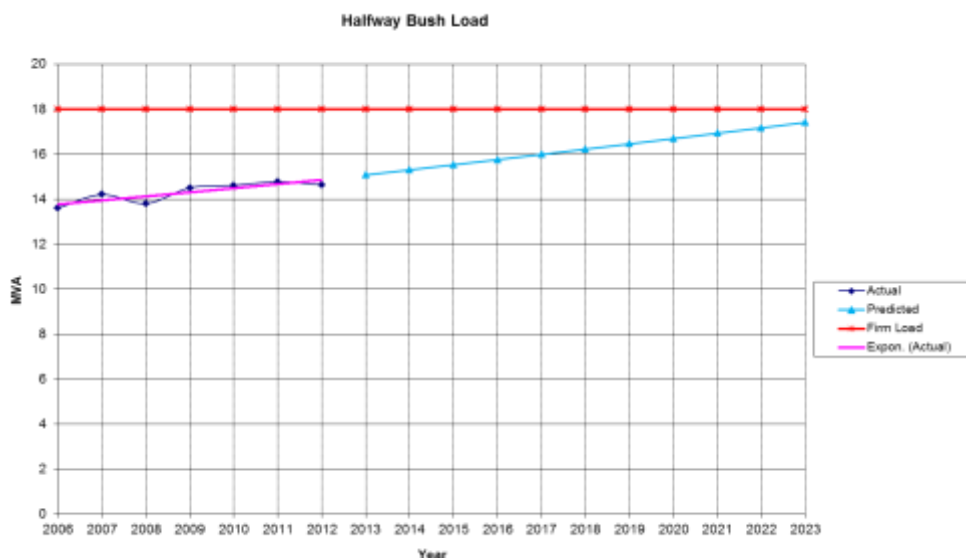


Figure 6.20 – Halfway Bush Zone Substation Load prediction

South Dunedin

Andersons Bay Substation

Figure 6.21 illustrates the load predictions for Andersons Bay zone substation. Load on the Andersons Bay substation has been variable. It is not currently predicted that the load will reach the firm capacity within this planning period. Some load could be transferred to St Kilda but it is expected that most of the equipment at Andersons Bay will be at the end of its economic life in 2021 so it is proposed the substation be upgraded with new transformers and switchgear at this time.

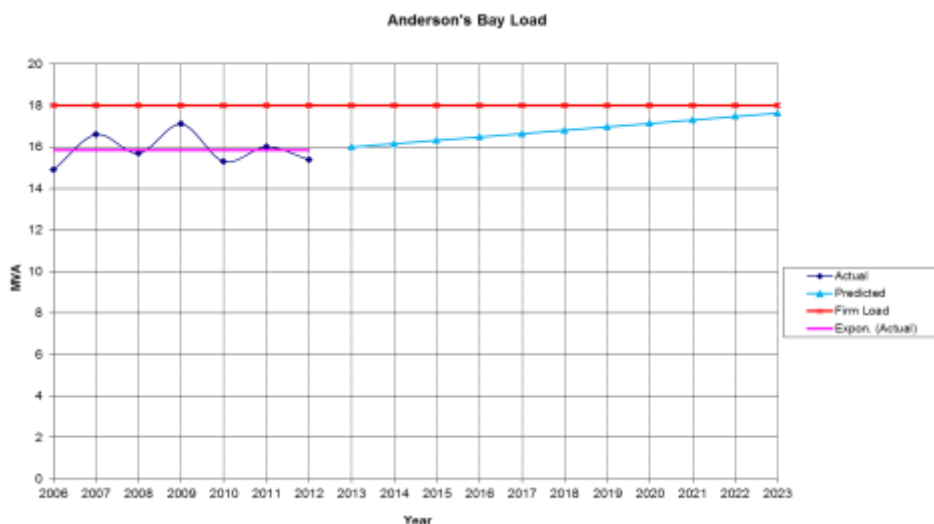


Figure 6.21 - Andersons by Zone Substation Load prediction

Macandrew Bay Substation

Slow steady load growth on the Otago Peninsula is expected to result in feeder off-loading issues with feeder AB7 being the first to be affected. The installation a substation would provide additional off-load capacity for the Port Chalmers and Andersons Bay substations. The timing of the project is driven by three factors, the Andersons Bay and Port Chalmers zone substation loads and the Peninsula feeder loads. This project is not currently scheduled but this will be reviewed annually.

6.5.5 Zone Substation - Non-Transferable Load

Along with demand projections, load risk analysis is also carried out on an annual basis to monitor and mitigate risk of complete loss of service. Together, this information is used as part the planning and decision-making criteria for new capital investment and renewal needs.

In the event of a complete outage occurring at a zone substation, only a portion of the substation load can generally be transferred to adjacent substations. Table 6.11 lists the zone substation non-transferable load sorted by magnitude of the winter non-transferable MW¹². This provides a clear statement of "load at risk" Table 6.12 combines this with the load prediction information as well as information in priority customers to provide a picture of high-risk areas of Aurora network.

¹² The risk management plan for zone substations is contained in Policy Document QP 1602/21. This procedure contains schedules for off-loading zone substations. It is reviewed every two years. Note that a review of load at risk commenced in 2012 and updated figures will be provided in Aurora's 2014/15 AMP.

Table 6.11 – Zone substation non-transferable load schedule

Zone Substation	% Domestic	Winter Loads (MW)			Summer Loads (MW)		
		2008-2010	Non-transferable		2008-2010	Non-transferable	
		MW	MW	%	MW	MW	%
Wanaka	80	20.3	18.8	92	13.5	12.0	89
Alexandra (2007)	40	12.4	12.3	99	9.6	9.4	98
Andersons Bay	95	17.1	10.0	59	11.3	6.2	33
Cromwell	50	10.0	8.9	88	7.7	6.7	87
Frankton	40	13.9	6.1	44	10.4	3.9	38
Commonage	60	9.8	6.0	61	5.5	4.4	80
Port Chalmers	50	7.9	5.8	73	7.1	4.3	61
Green Island	80	13.7	5.7	42	11.6	4.7	41
North City	0	20.0	5.5	28	16.9	4.8	28
Arrowtown	75	7.9	5.4	68	5.9	4.4	75
Queenstown	60	14.7	5.1	35	11.9	3.9	33
Mosgiel	20	8.4	5.0	60	7.0	3.4	49
St Kilda	70	15.7	4.9	31	13.5	3.1	23
Corstorphine	95	14.3	4.7	33	9.5	2.9	31
Ward Street	30	12.5	4.6	37	12.0	2.8	23
Neville Street	60	14.8	4.3	29	11.7	3.1	23
Clyde/Earns	20	4.1	4.1	100	4.1	4.1	100
Halfway Bush	95	14.6	2.5	17	10.9	2.6	24
Smith Street	0	16.8	2.4	14	14.1	0.7	5
Omakau	10	2.0	2.0	100	2.1	2.1	100
Kaikorai Valley	50	10.2	1.9	19	8.7	1.3	15
North East Valley	95	11.8	1.8	15	8.2	0.3	4
Willowbank	60	13.7	1.7	12	11.0	0.6	5
Roxburgh	20	2.6	1.7	65	2.8	1.9	68
Fernhill	90	6.2	1.3	21	4.4	0.1	2
Maungawera	10	2.3	1.0	43	2.1	0.7	33
South City	0	15.8	0.9	20	13.4	0	0
Remarkables	0	0.8	0.8	100	0	0	0
Coronet Peak	5	4.6	0.5	11	1	0	0
East Taieri (2)	75	16.7	0.5	3	12.8	0	0
Outram	60	2.8	0	0	2.5	0	0
Dalefield	30	2.3	0	0	1.6	0	0
Queensberry	10	1.7	0	0	2.4	0	0
Ettrick	10	1.7	0	0	2.1	0	0
Berwick	10	1.2	0	0	1.2	0	0

Based predicted demands against firm load capacity, the substations that Aurora considers to be potentially at risk of capacity issues in the 10 year planning period are:

GXP area	Substation
Cromwell	Cromwell, Queensberry, Wanaka, Maungawera
Frankton	Arrowtown
Halfway Bush	Smith Street

Based predicted demands against firm load capacity, the substations that Aurora considers to be potentially at risk of capacity issues in the long term (beyond 10yr AMP planning period) are:

GXP area	Substation
Clyde	Omakau
Cromwell	Maungawera
Frankton	Dalefield, Frankton, Remarkables
Halfway Bush	Halfway Bush
South Dunedin	Andersons Bay, South City

Table 6.12 combines the above information with the highest ranked 'load at risk' substations and then compares that with the substations with the highest percentage of domestic customers potentially affected as a consequence of an outage. The table below also includes the substations that have priority 1 customers (such as hospitals) as well as highest number of priority 2 customers (such as other utility providers) within that supply area

Table 6.12- Potential high-risk areas of Aurora network.

GXP area	Capacity Issues	Load at Risk MW range (6-18)	% Domestic ICP's (70-95%)	Priority 1 and 2 ICP's
Clyde	Omakau	Alexandra		
Cromwell	Cromwell, Queensberry, Wanaka, Maungawera	Wanaka, Cromwell	Wanaka	
Frankton	Arrowtown Dalefield, Frankton, Remarkables	Frankton, Commonage, Arrowtown, Queenstown	Arrowtown, FernHill	
Halfway Bush	Smith Street ,Halfway Bush	Port Chalmers, Green Island	Green Island, Halfway Bush, NEV, East Taieri,	Halfway Bush, Green Island, East Taieri, Kaikorai Valley, Smith Street, Willowbank
South Dunedin	Andersons Bay, South City	Andersons Bay, North City	Andersons Bay, Corstophine, St Kilda	North City

Considering all this information combined it is clear that, in Dunedin, Andersons Bay, Green Island and Halfway Bush reflect critical parts of the network and are therefore presenting as a priority for Aurora to focus on. Halfway Bush GXP area contains most of these substations. In Central, Wanaka, Cromwell, Frankton and Arrowtown are presenting as priority.

6.6 Network Development

This section outlines the network development plan required to upgrade Aurora's distribution system. It details the expansion and upgrading considered necessary to accommodate predicted future network loading. The plan also proposes works to improve network safety and reliability.

A detailed description of the projects to be carried out within the next 12 months is provided. Project proposed for the following four years are also covered, with detail provided for those that are significant (for example: the system control and communication projects). Those planned for the remainder of the AMP planning period are also highlighted. See Appendix E for further detail in the projects proposed within these timeframes.

For complex proposals, separate detailed development reports are prepared. These reports describe the proposed development, consider alternatives, and provide detailed cost estimates and economic analysis. The content of this section provides an overview of what is contained in the development reports. Reference to the detailed reports (DR) is made where necessary.

6.6.1 Overview of projects

The timing of major projects is presented in Table 6.13. The projects in this table are divided into those driven by System Growth and those driven by Renewals/Replacements.

Under each of these, projects are listed under the following categories: Subtransmission, Zone Substations, Distribution, Low Voltage and Other network assets (such as secondary assets).

The estimates are based on a financial year of 1 July to 30 June (the 2013/14 year does not include carry-overs from 2012/13). The definition of capital & operational expenditure categories were provided in Table 6.1 and based on the Commerce Commissions definitions for expenditure drivers.

Table 6.13 – Time Line of Major Capital Projects

Project Type	Asset Type	Project No.	Short Description	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Total 2013-2022
Growth	Subtransmission	3021	Install 3rd 33/66kV auto transformer at Cromwell GXP and create 66kV bus						200	1,800			2,000
		3216	Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.	250	2,250								2,500
		4182	Upgrade Glenorchy supply to 33 kV	1,080									1,200
	Zone substations	2611	New Jacks Point zone substation							300	1,350	1,350	3,000
		3019	Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.		40	1,980	1,980						4,000
		3022	Construct Riverbank Rd 66kV switching station.	100	1,950	1,950							4,000
		3023	New zone substation in Maori Point Rd - Tarras irrigation scheme	2,835									4,200
		3024	Install two new 24 MVA transformers at Cromwell substation		250	1,125	1,125						2,500
		3038	Upgrade Andersons Bay substation. New Xfms and switchgear.					450	1,350	2,700			4,500
		3414	Upgrade Smith St Substation - new 24MVA transformers and HV switchgear					450	2,025	2,025			4,500
		3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.				250	2,250					2,500
		3438	New 66kV Switching Station at Queensberry						300	2,700			3,000
		4135	Upgrade Maungawera Substation from 3 to 5 MVA	1,485	1,485								3,300
		TBC	Fire , Security and Earthquake Upgrades	200	200	200	200	200	200	200	200	200	1,900
			Queensberry/Bengido upgrade										3,500
	Distribution and LV lines	3165	New Wanaka Feeder 2751										600
		3428	Install new HV feeder in Cromwell to Leitrum St										500
		4161	Upgrade of Maungawera 11kV feeder to Devon Dairy	378									420
	Distribution and LV cables	4183	HV Distribution - Tarras Irrigation Scheme	3,025	1,025								4,500
	Distribution substations and transformers	3061	Dunedin load growth projects yet to be identified	100	100	100	100	100	100	100	100	100	1,000
		3062	Central load growth projects yet to be identified	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	9,500
		3200	Extra cost of Dual ratio distribution transformers	80	80	80	80	80	80	80			640
Renewal	Subtransmission	3171	Replace Kaikorai Valley 33kV cables				290	2,610					2,900
		3469	Replace Ward Street 33kV gas cables						420	3,780			4,200
		3470	Replace Willowbank 33kV gas cables			390	3,510						3,900
		3471	Replace Smith St 33kV gas cables					350	3,150				3,500
		4038	Replace Lower Shotover River 33 kV Crossing Old School Road with cable across bridge.										1,000
		4212	Port Chalmers to Peninsular Harbour Crossing Upgrade										800
		TBC	Replace Neville St 33kV gas cables	200	1,800								2,000
	Zone substations	2324	Rebuild Neville St zone substation on new site	600	5,400								6,000
		4179	Upgrade Outram Zone Substation	300	2,700	900							3,900
	Distribution and LV lines	4204	Pole replacements 2012/13 Dunedin Area	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	10,000
		4205	Pole replacements 2012/13 Central Area	2,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
	Distribution and LV cables	2622	Dunedin UG link box upgrades, three per year.	150	150	150	150	150	150	150	150	150	1,500
		3272	Undergrounding of OH from Frankton Sub to Glenda drive for LTSA roading work.										500
	Distribution substations and transformers	3031	Annual Replacement of pole mounted substations	250	250	250	250	250	250	250	250	250	2,500
		3032	Ongoing replacement of distribution transformers	120	120	120	120	120	120	120	120	120	1,200
	Distribution switchgear	3029	Ongoing replacement of Andelect Boxes in the Dunedin Area	36	36	36	36	36	36	36	36	36	360
		3211	Replace Pacific fuses in Central	60	60	60	60	60					360
		TBC	Replacement of oil-filled switchgear	120	120	120	120	120	120	120			920
	Other network assets	2630	SCCP P4 - Upgrade Dunedin SCADA RTUs	385	364	238	378	105	126	-	-	-	1,981
		4214	Replacement of Dunedin street lighting ripple control relays.	80	80	80							320
		TBC	SCCP P1 (Part A) - New System Control room	350	200	-	-	-	-	-	-	-	550
			SCCP P1 (Part B) - Future SCADA master station operating system upgrade	100	100	2,700	2,000	350	-	-	-	-	5,350
			SCCP P2 - DUD, Central and DUD - Central Comms Upgrade	830	170	170	-	-	-	-	-	-	1,723
			SCCP P5 - Upgrade Central SCADA RTU's	200	495	350	-	-	-	-	-	-	1,045
			SCCP P6 - Dunedin Subtransmission network protection system upgrade	860	320	-	180	-	-	-	-	-	1,740
			SCCP P7 - Aurora ICCP System	120	-	-	-	-	-	-	-	-	340

The following section is structured by GXP area and begins with the Central Otago network (Clyde, Cromwell, Frankton), followed by the Dunedin network (Halfway Bush and South Dunedin).

6.6.2 Grid Exit Points

Clyde GXP

Section 6.4 indicated that there is adequate GXP capacity at Clyde for the foreseeable future. However, the replacement of ripple injection is planned. Ripple injection for Clyde GXP is based in the Alexander zone substation. Although the existing injector has capacity to cope with many years of load growth, this asset has effectively passed its nominal life of 20 years, being installed in 1985. While there is a spare unit available (ex Frankton), is too is older than 20 years and given that spare parts are no longer available for either unit, replacement is deemed necessary to reduce the risk associated with failure. Development report DR123 investigates the future options for the Alexandra injection units and recommends that the injection unit be replaced with a new 200kW unit that is the same model as used at all other sites. This was initially planned for May 2013, but timing of this is now being reviewed.

Cromwell GXP

The Cromwell transformers were upgraded in 2009 resulting in the n-1 ratings listed in Table 6.14. Section 6.4 indicated that there is adequate capacity at Cromwell GXP for the short-term, however the off take load is predicted to exceed 40.9 MVA during the winter of 2022 and the load on Cromwell zone substation is growing with peak demand now exceeds its 9 MVA firm capacity. There is a protection limitation that constrains the rating of the T8 transformer at the Cromwell GXP site. One solution for this is to install duplicate protection on affected feeders. The main project associated with the Cromwell GXP area is Upper Clutha, discussed in Section 6.6. It is acknowledged that Transpower plans to convert the outdoor switchyard to indoors by 2025, but this work has yet to be scheduled.

Table 6.14 – Cromwell GXP transformer n-1 ratings

Voltage	Continuous n-1 MVA	Winter 24-Hour Contingency MVA
220 kV	150	202
110 kV	97.2	108.8
33 kV	40.9	40.9

Frankton GXP

Section 6.4 indicated that it is predicted the 66 MVA continuous n-1 rating at this site will not be exceeded during the planning period. The ripple injection plant was upgraded in 2010 and the new injectors will cope with up to 100 MW of connected load. Constraints in the Wakatipu Basin Ring and/or growth in Jack's Point may drive the need to install an additional feeder (see Section 6.6.3). Installing an additional feeder will be easy providing it is possible to obtain the existing switchgear model. In this case, Aurora is reliant on Transpower to advise before production of the current model ceases in order to facilitate advance purchase of a breaker if necessary (there is space in the switch room at Frankton GXP for two additional 33 kV feeder circuit breakers). There are currently no other major projects planned by Aurora at this GXP site within the next 10 years.

Halfway Bush GXP

Section 6.4 indicated that the off-take peak exceeds post-contingency rating. The connection of the 36 MW TrustPower Mahinerangi wind farm, which was established during 2011, assists to reduce some of the off take on the Halfway Bush GXP. Further to this, a contingency plan has been prepared in the event of failure of the Transpower transformer (Development Report DR24). Aurora also plans to move other substation loads (e.g. Neville Street) to the South Dunedin GXP by May 2015 when the Neville Street substation and gas cables are upgraded, see Sections 5.5 and 6.6. This would reduce the demand on Halfway Bush by approximately 14 MVA.

There are also a series of projects being implemented by Transpower that Aurora has the opportunity to benefit from. For example: Transpower plans to convert the remaining outdoor 33 kV circuit breakers to indoor units in 2016. At this time, it may be desirable to have Transpower fit 33 kV VTs to the Waipori lines which will eliminate

the need for the outdoor VTs in the take-off area. Transpower also plans to remove the two 110/33 kV transformers and replace them with a single 120MVA 220/33 kV transformer operating in parallel with the existing T5 transformer in 2017. This will enable the present separate 33 kV buses at Halfway Bush to be operated as one solid bus which will have some operational advantages for Aurora. When the new transformer is installed, it is assumed it will be fitted with an NER. It is proposed that Transpower be requested to install an NER on the existing T5 transformer at the same time. This will allow the use of light duty cable screens when 33 kV cables from Halfway Bush are renewed which reduces the new 33kV cable cost by up to 30%.

South Dunedin GXP

Section 6.4 outlined a constraint where the 81MVA limit would be exceeded when the Neville Street Substation load is transferred to South Dunedin. The work required to eliminate the constraint is to change the metering CT ratio from 1200/1 to 2400/1 and recalibration of the meters. This work will be carried out in conjunction with the switchgear up grade project detailed below.

Conversion of Switchgear to Indoor

Transpower plans to convert the 33 kV switchgear at South Dunedin from outdoor units to indoor units with completion scheduled for early 2014. In conjunction with the switchgear conversion project, Aurora has requested that an additional circuit breaker be installed to facilitate the connection of the Neville Street substation to the South Dunedin GXP. Transpower has been requested to allow space in the new switch room to accommodate the re-connection of the South City No.2 feeder in the future. Refer to Development Report DR128 for details relating to the conversion project.

Installation of NER on T1 and the South Dunedin GXP has been completed

6.6.3 Sub-transmission

The following sections outlines the subtransmission considered to warrant investment over the 10 year planning period in response to the key asset management drivers. The section is structured by GXP area, beginning with the zone substations in Clyde, Cromwell and Frankton then leading into the zone substations in Halfway Bush and South Dunedin.

Clyde

Dairy Creek Irrigation Project

There is a proposal to establish an irrigation scheme that will pump water from Lake Dunstan at Dairy Creek just above the Clyde Dam. The scope of this project has varied over time, and although the likely final extent of the project still has a high level of uncertainty, a preliminary proposal is for the load to be supplied via two new zone substations one close to Clyde (2 X 10 MVA) and the other close to the North end of Springvale road (5 MVA). The Clyde substation can be supplied from the existing Clyde to Alexandra 33 kV lines and the Springvale Road Substation from the Omakau line. It is expected significant upgrades would be required to the HV distribution network in the area including upgrading 6.6 kV circuits to 11 kV.

No expenditure provision has been made in this plan due to the uncertain nature of this project

Cromwell

Upper Clutha 66 kV

The Upper Clutha 66kV network is within the Cromwell GXP area. The n-1 capacity of the existing Upper Clutha 66 kV network has the following constraints:

- ability to maintain 11 kV target volts in the Wanaka area;
- rating of Cromwell 33/66 kV auto transformers;
- rating of the 66 kV Dog conductor;
- firm 33 kV capacity at the Cromwell GXP.

Works that will reduce these constraints are:

- installation of 66 kV bus at Riverbank Road that enables the Wanaka transformers to operate in parallel when one 66 kV line is out of service which reduces volt drop;

- installation of a 66 kV bus and extra auto transformer at Cromwell that will prevent overloading an auto transformer when one line is out of service;
- installation of 66 kV bus at Queensberry which will reduce the volt drop when one line is out of service;
- establishment of GXP at Queensberry and the completion of the Riverbank Road to Queensberry line via Hawea.

A schedule of the required upgrade projects with estimated costs is presented in Table 6.15 (this assumes no support from the Hawea generation; see long term programme below).

Note that the development of large scale irrigation in the Tarras area would likely change the order and timing of the proposed programme for this area as it may shift the current constraint from a voltage issue at Wanaka to a line rating issue between Cromwell and Tarras. A final decision on whether the Tarras Scheme will go ahead is likely to be made in the first half of 2013.

Under the current scenario, however, the future Aubrey Road substation is not predicted to proceed during the planning period. It is proposed that loading on the Wanaka zone substation be relieved by the installation of transformers at the Riverbank Road substation. It is recommended land for the Aubrey Road substation be purchased well in advance of being required, if available.

Aurora has purchased land adjacent to the proposed Contact Energy generation¹³ site to accommodate substation equipment and to provide 66 kV line access. During 2013, the land required for electricity purposes will be subdivided off the main block and designated for substation and transmission line use. This will enable Aurora to sell the balance of the land.

Long term programme

The long term geographic layout in is illustrated in Figure 6.20. Progress toward this configuration will depend on load growth and the installation of generation at Hawea (a project proposed to be delivered by Contact Energy). Development Report DR40, written in 2008, considered various connection options. There has been limited progress on the Hawea generation project and although the project is still 'active'. At present it is assumed that the original timeframe proposed to complete the generation still remains at 2017.

As such, projects for the establishment of the generation connection proposed by Aurora have been put on hold, with the exception of land subdivision as outlined previously. Also note that the Hawea substation will not be required until the Maungawera substation is fully loaded (see Section 6.6).

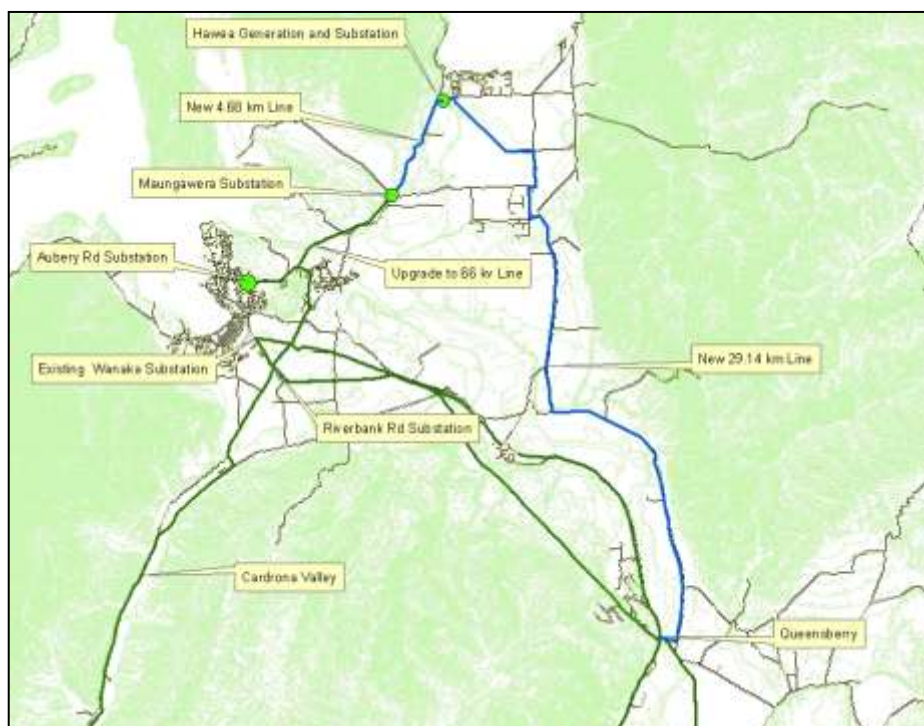
The long term proposal to establish a 220/66 kV GXP at Queensberry will be very expensive and is expected to exceed \$30 million. This would be installed by Transpower and funded by Aurora via a new investment agreement. The application of demand side management could be an acceptable solution to Wanaka consumers to minimise line charges.

The future development of either of the proposed Luggate or Queensberry hydro generation would allow the cost of transmission upgrades in the area to be shared with other parties. An alternative is to establish a 110 kV bus at Cromwell and construct a double circuit 110 kV line from Cromwell to Queensberry along the east side of the valley to supply two 110/66 kV transformers. It is possible that the installation of diesel generation that would only be operated in during a contingency event to defer a transmission upgrade could be economic.

¹³ In 2008, Contact Energy submitted an application to install 2 X 8 MW generators at Lake Hawea but it has not confirmed a starting date for the project and has given no indication of when it can confirm a starting date.

Table 6.15 – Upper Clutha 66 kV subtransmission project schedule

Project Details	Project No	Estimated \$000	Completion
Obtain land and designation for Riverbank Road switching station	2969	175	Dec 2012
66 kV transmission to Hawea	2514	3,500	On hold
Construct Hawea substation for generation connection	2798	3,500	On hold
Construct Riverbank Road switching station	3022	4,000	May 2016
Install 66 kV cables Riverbank Road to Wanaka and Riverbank Road to UC1	3216	2,500	May 2016
Establish 66 kV bus at Cromwell + third auto transformer	3021	2,000	May 2021
Install transformer and 11 kV switchgear at Riverbank Road substation	3437	2,500	May 2019
Create 66 kV bus at Queensberry	3438	3,000	2022 +

**Figure 6.20 - Geographic layout of Upper Clutha long term subtransmission****Maungawera**

An upgrade of the HV lines from Maungawera zone substation to Devon Dairy is proposed as part of the Devon Dairy irrigation proposal in order to avoid excessive volt drop. The timing of this upgrade is dependent on the expansion of the Devon Dairy development. It is estimated the upgrade will be required when the Devon Dairy demand reaches 1 MVA. See Figure 6.21 for the line route. Previous plans had the Maungawera substation being replaced by a substation at Hawea (as discussed in the previous section). Due to the development of dairy farming close to the Maungawera substation it is now proposed to retain the Maungawera substation.



Figure 6.21 - Route of line upgrade to Devon Dairy Development

Wanaka 33 kV

At present, the Cardrona and Maungawera substations are supplied from the Wanaka 33 kV bus. The Wanaka 33 kV subtransmission network is supplied from the 33 kV tertiary windings of the Wanaka 66/33/11 kV, 30/10/24 MVA transformers. If the 11 kV is fully loaded the maximum n-1 rating of the 33 kV supply is 6 MVA. The 2012 peak load was 4.5 MVA. It is not expected the 33 kV supply will become constrained within the planning period due to the plan to transfer the Cardrona substation load from 33 kV to 66 kV when the Riverbank Road substation is constructed.

Frankton

Wakatipu Basin 33 kV Ring

The Wakatipu Basin Ring is within the Frankton GXP area. Section 6.4 identified the need to improve the capacity of the ring (see Figure 6.22 for the configuration), which consists of Ferret and Mink conductor and short sections of cable. To improve the n-1 capacity of the ring either requires upgrading of the existing line conductors and cables or the installation of a third circuit into the area. The 70mm² cable upgrade was carried out in 2012.

In terms of the third circuit, there are two possible options. Both of these options require the installation of an additional 33 kV feeder outlet from the Frankton GXP. This outlet will also serve the Jacks Point substation when it is commissioned.

The options for supplying the third circuit to Arrowtown from the North Bank of the Shotover River are detailed below:

Option 1 is to install an additional 33 kV circuit from the north bank of the Shotover River to Arrowtown. See Figure 6.23 for the proposed circuit route and Figure 6.24 for a single line diagram. The circuit would have 800m of cable at the Arrowtown end, 700m of cable at Shotover end and 10 km of 33 kV overhead line. The line route is in the road reserve and mainly involves converting 11 kV line to 33/11 kV line.

Option 2 is to install a 33 kV circuit from the same source as option 1 but to run it to a new substation in the vicinity of the Coronet substation. The cable requirements for this option are similar to option 1, but only require 6 km of 33 kV line. The line route is also in the road reserve and mainly involves converting 11 kV line to 33/11 kV line.

Option 1 is preferred at present, but if the load on Dalefield or Coronet substations grows significantly, such that a new dual transformer substation is required in that area, then option 2 could be the more economic solution.

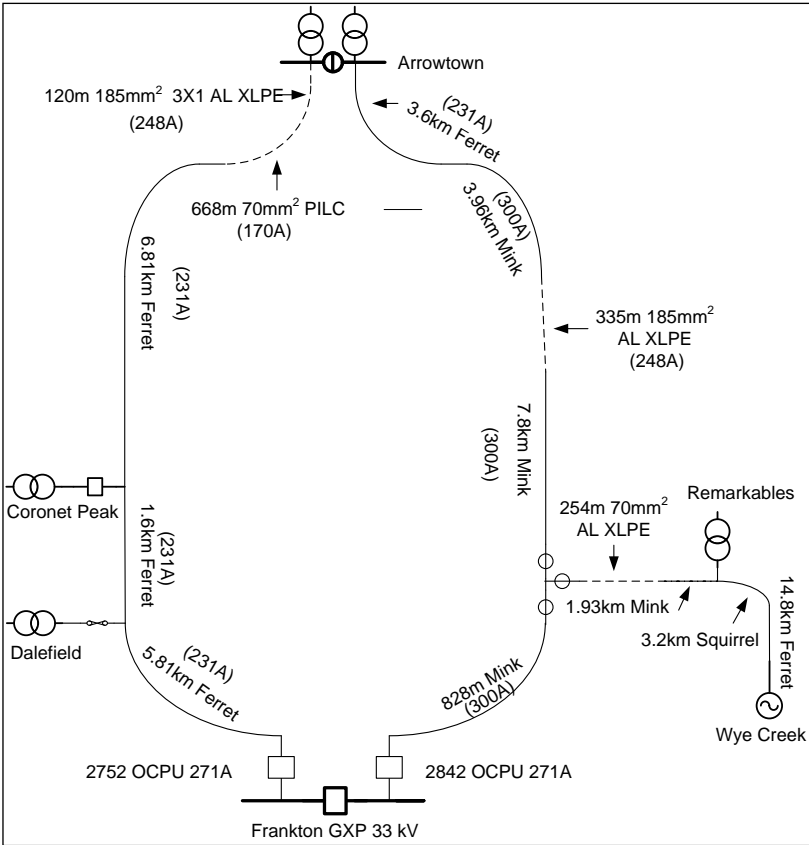


Figure 6.22 – Wakatipu basin 33 kV ring

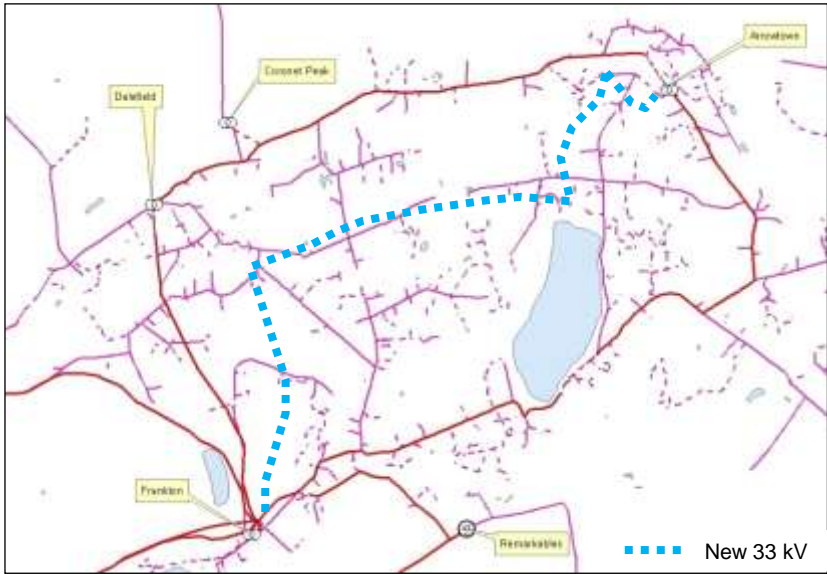


Figure 6.23 - Wakatipu ring upgrade – option 1 third line to Arrowtown

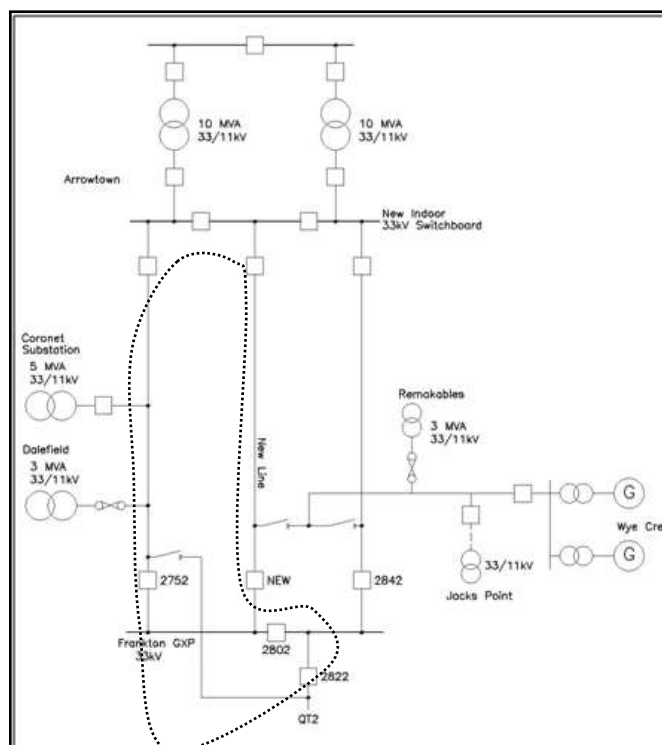


Figure 6.24 - Wakatipu 33 kV ring upgrade – SLD option 1

Shotover 33 kV River Crossing on Wye Creek Line

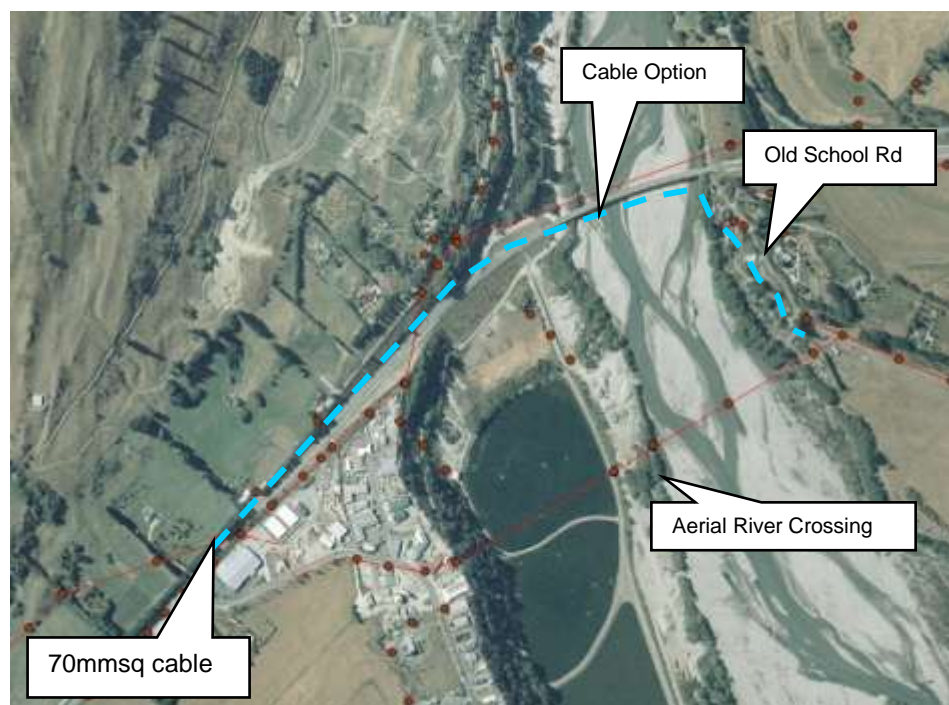
The 33 kV aerial river crossing across the Shotover River is nearing the end of its life. The existing river crossing structures have not been able to be inspected for structural integrity as they are in the river and not normally accessible. Options are:

- (i) to rebuild the line or
- (ii) to install a 33 kV cable (300 mm² XLPE) (1.3 km) across the Shotover bridge along the route shown on the following page.

Option (ii) is preferred because of:

- the precarious state of the river crossing and difficulties in re-establishing a secure crossing; and
- the line is crossed by the Transpower 110kV line close to the south bank of the crossing which are likely to exclude higher termination structures, which are required in order to avoid having structures in the middle of the river; and
- elimination of the visual impact of the 33 kV line through the industrial estate; and it will facilitate the installation of a duct in the cable trench for the installation of an additional 11 kV feed across the Shotover River to supply Lake Hayes Estate and the proposed Stalker subdivision.

See concept plan on the following page and Table 6.13 in Section 6 for project timing and estimated cost.



Location of Shotover River Crossing

Glenorchy

Development Report DR132 (project 4182) outlines the upgrade options which are:

- upgrade line to 33 kV and install zone substations at Closeburn and Glenorchy;
- install a diesel generator at Glenorchy; and
- extend the 11 kV distribution from Fernhill to supply the Closeburn area.

The option to upgrade the line to 33 kV is recommended. This option requires the establishment of zone substations at Closeburn and Glenorchy. Customers at Mt Creighton and transformer WQ25 will be supplied by 33 kV/415 volt transformers. The Closeburn substation will be located at the site of the existing voltage regulators. It is proposed the existing regulators be retained and a 2.5 MVA 33/11 kV sealed distribution type transformer be installed to supply the regulators from the 33 kV line.

It is proposed that the 1 MVA transformer that was refurbished for the Remarkables substation be installed at Glenorchy and connected to the existing voltage regulators. Aurora does not own the land at the Glenorchy regulator site so easements or land purchase will be required. This will be reviewed in 2013/14.

6.6.4 Zone Substations

Aurora's network contains 36 zone substations, 18 in Dunedin and 18 in Central Otago. The following sections outline those that are considered to warrant further investigation or investment over the 10 year planning period in response to the key asset management drivers discussed in Section 2 as well as the growth and demand issues discussed earlier in Section 6.5. The following section is structured by GXP area, beginning with the zone substations in Clyde, Cromwell and Frankton then leading into the zone substations in Halfway Bush and South Dunedin.

Clyde

Alexandra Substation

There are no major capital projects planned for this site over this planning period, however future options to reinforce the supply to Alexandra are to either upgrade the Alexandra transformers to 12/24 MVA units or

establish a new zone substation. The establishment of a new zone substation is preferred with a proposed site in Dunstan Road adjacent to the Omakau 33 kV.

Cromwell

Queensberry Substation

The potential upgrade projects at this site are driven by the Bendigo and Tarras irrigation schemes. If the Tarras irrigation project proceeds and the new Maori Point Road substation established, as detailed below, the Queensberry substation could be removed. Conversely, Queensberry Zone Substation is likely to be required to enable sufficient network capacity for an additional 1.4 MVA of irrigation load to be supplied in the Bendigo area. Based on the existing network capacity available, the main issues with this is that it would create an unacceptable voltage drop in the Bendigo area and will cause an overload on the Queensberry Zone Substation Transformer.

The load growth predictions outlined in Section 6.4 identified that the substation transformer rating can be increased to 4.4 MVA by the addition of fans. However, there would still be a shortfall in load growth capability if this option were to proceed. In addition, the location and size of the Queensberry site may not be entirely suitable for the upgrades required. DR 159 contains detailed analysis and provides a range of options that make up an overall solution to the potential constraints in this area, including cost estimates that range between \$40,000 – \$3.5M. The installation of transformer fans, an air break switch and a set of voltage regulators is proposed as the first phase of delivering the solution and \$160,000 has therefore been allowed for in 2013/14.

Maori Point Road Substation

A new substation is an option proposed to provide a reliable adequate supply for the Tarras Irrigation Scheme. The scheme proposed for the Tarras area could require up to 11 MW of pumping. The current proposal will require a new 2 X 20 MVA zone substation to be constructed at the west end of Maori Point Road and be supplied from the Upper Clutha UC2 66 kV line. See development reports DR133 and DR133A for project details.

The following section (6.6.5) discusses the associated distribution line upgrade requirements and provides a plan of the proposed network configuration.

Cromwell Substation

While *normal* load is not causing capacity constraints at present, the load on Cromwell is growing and the peak demand now exceeds its 9 MVA firm capacity. The 5 MVA mobile substation is being used to provide n-1 cover. It has previously been proposed that the transformers be upgraded prior to the 2015 winter when it was predicted the load would reach 12 MVA. Present load predictions (see section 6.4.4) have reduced, with the 12 MVA limit now predicted for the winter of 2020. It is proposed that commissioning occurs in 2017 (see DR 130).

In the event of a Cromwell transformer failure there is a 7.5/10 MVA transformer that is currently stored at Arrowtown (removed from Frankton) that will be available to be installed at Cromwell, but this would take several days to install. Load control could also be used to alleviate some issues during such an event. Also see comments for Arrowtown substation. Note that a review on the movement of transformers between zone substations is planned to ensure network needs are approached from a strategic perspective.

Wanaka Substation - Riverbank Road proposal

In the 2009-2019 Development Plan, it was proposed that Wanaka be off-loaded by the construction of a new substation in Aubrey Road. It is now considered the most economic solution is to install one 24 MVA transformer with associated 11 kV switchgear at the Riverbank Road switching station prior to the winter of 2019. Up to 8 MVA of load could be transferred from Wanaka to Riverbank Road by connecting to the existing HV feeders adjacent to the Riverbank Road site. This is the same load transfer that would be expected from the establishment of a substation in Aubrey Road. The advantages of Riverbank Road over Aubrey Road are:

Riverbank Road will be supplied by duplicate 66 kV circuits whereas Aubrey Road would have been on a 66 kV spur; and the cost of installing a transformer at Riverbank Road will be significantly less than setting up a new substation in Aubrey Road.

The Riverbank Road switching station is scheduled to be commissioned in 2016 to reduce volt drop during an outage on one of the upper Clutha 66 kV circuits, refer to Section 6.5.4. It is proposed to install a 24 MVA transformer at Riverbank Road in 2018/19 with a second transformer being installed when it is no longer possible to completely off-load Riverbank Road onto adjacent substations; however, this is expected to be beyond the planning period.

Maungawera Substation

At present, the Maungawera and Cadrona substations are supplied from the Wanaka 33 kV bus. The previous AMP had the Maungawera substation being replaced by a substation at Hawea. However, due to the proposed development of dairy farming driving irrigation demands close to the Maungawera substation it is now proposed to retain the Maungawera substation. The Hawea substation will not be required until the Maungawera substation is fully loaded.

In the 2011-21 Plan, it was proposed that the Maungawera substation be removed and a new substation be established at Hawea which would utilise the 66 kV transmission installed for the Contact Energy Hawea generation project. Since then, a significant four-stage irrigation load is proposed in the Camp Hill Road area to service a dairy farm development. Stage 1 of the project has already been implemented. This development will result in the load centre of gravity moving closer to Maungawera than Hawea.

In response to the above, it is now proposed that the Maungawera substation be upgraded from a 3 MVA to 7.5 MVA when it becomes fully loaded, instead of installing a substation at Hawea. Deferment of the substation upgrade and some voltage support in the case of a 66 kV Upper Clutha line outage (Refer to DR126 for further detail)

Consideration is also being given to relocating the Cardrona generator at Maungawera. This could enable the. The Cardrona generator needs to be removed as it is blocking access for the mobile substation into the Cardrona site.

A review the site options has been carried out. It is proposed that land will be obtained during 2013/14 and the site be designated for electricity use.

Frankton

Arrowtown Substation

The load is not predicted to reach 10 MVA during the planning period. However the upgrade proposed in the 2011 AMP - to install transformers during the 2016/17 summer to increase the firm capacity to 11.5 MVA - is still considered viable, particularly as there is increasing risk that the mobile substation will not be available when required because it is backup for 11 sites. In 2012, a parking bay was constructed in order to accommodate for the mobile substation at this site. The mobile substation can provide cover for a transformer outage up to a load of 10 MVA.

Associated with the future proposed upgrade is the installation of indoor 11 kV and 33 kV switchgear and supply the transformers from 33 kV circuit breakers rather than the fuses at present. The 33 kV switchgear configuration will be designed to accommodate the third 33 kV circuit as outlined in the Wakatipu Basin Ring proposal and detailed in Figure 6.24.

The noise from the existing 5 MVA transformers is in excess of the District Plan requirements. Noise tests on the 10 MVA Frankton transformer indicate they can meet boundary noise limits, but will require the transformer fans to be replaced with new low noise units.

Remarkables Substation

The Remarkables ski field has a four stage upgrade planned. Stage one is scheduled to be completed for the winter of 2014 and will increase the field maximum demand to approximately 2 MVA. Stage 2 will add an extra 200 kW. However, it is proposed to install a Micro Planet LV voltage regulator at distribution transformer WS200 to keep the voltage within regulatory limits as the application of line drop compensation (LDC) required to maintain a constant voltage at the ski field will result in excessive voltage variation for the consumer supplied from distribution transformer WS200. Refer to development report DR126 for detailed consideration of supply options for the Remarkables ski field. The timing of stages three and four is uncertain so no financial provision has been made for these stages.

Proposed Jacks Point Substation

As outlined in section 6.5.4, timing of substation construction depends on uptake of the lots in this area, which has been slow in the recent past. A review of the assumed growth rate will be carried out in 2013/14, with appropriate adjustments made to the assumptions for timing of the proposed substation. The proposal at this stage is to install a 33/11 kV substation at Jacks Point that will be supplied from the 33 kV line to Wye Creek. The substation

will be designed to eventually accommodate two 10 MVA transformers. A substation site exists and a 33 kV cable has been installed from the Wye Creek line to the site.

Jacks Point is presently supplied from Frankton feeder 7784 via recloser 7375R up to a load of approximately 2 MVA. To deliver 2 MVA to Jacks Point at 11 kV will require the installation of a voltage regulator when the load reaches 1.2 MVA. This is predicted to occur during the 2016 winter so the installation of a pair of single phase 100A regulators has been scheduled for 2015/16.

Halfway Bush

Smith Street Substation

Load was transferred from Smith Street to South City in 2005, to keep the demand on Smith Street below its firm rating which is determined by the capacity of the incoming circuit breakers. Smith Street load is currently predicted to reach its firm rating during the 2022 winter.

It is proposed that Smith Street be upgraded to 24 MVA transformers and the HV switchgear be replaced prior to the winter of 2020. The existing transformers and switchgear that was purchased in 1957 will be 63 years old by then and replacement likely to be justified on reliability grounds. It is proposed to replace 33 kV gas cables supplying Smith Street at the same time

Neville Street Substation

It is planned to move the Neville Street substation load to the South Dunedin GXP by May 2015 when the Neville Street substation and gas cables are upgraded, see Section 5.5 and 6.6. Part of the Neville St upgrade involves the establishment of a new substation site. This site is currently leased to an external party and the current lease agreement does not terminate until August 2015, by which time the premises must be vacated.

6.6.4.1 Zone Substation Buildings

An assessment of fire, security and earthquake risk for all of Aurora's zone substation buildings are being carried out in 2013. Outputs from this will contribute to the development of a long term programme of works, which will be incorporated into Aurora's 2014/15 AMP. Along with security and earthquake risk recommendations, this assessment will supersede previous recommendations on the risk and consequences of zone substation control room fire that identified sites to be fitted with gas flooding fire protection.

6.6.4.2 Zone Substation Switchgear

Switchgear associated with major projects is discussed in previous sections. The following outlines programmes for network-wide upgrades.

Relays

Older transformers are fitted with Buchholz and temperature relays containing mercury switches. These switches are prone to causing false tripping of transformers during earthquakes. An allowance has been made to progressively upgrade the relays to units designed to withstand earthquakes in both Central and Dunedin.

Installation of 33 kV Circuit Breakers

Several zone substation transformers in Central are only protected by 33 kV HV fuses. If a transformer protected by HV fuses has a fault then there is high probability the damage to the transformer will be extensive such that the transformer will be uneconomic to repair. If a transformer has both HV and LV circuit breakers, the Buchholz relay can clear faults quickly to limit winding damage. The Roxburgh T1 Transformer had to be scrapped after a fault in November 2011 that was cleared slowly by fuses. There is a proposed upgrade programme for fuse protected transformers.

Earthing Points

Many zone substations in the Central Region do not have dedicated earthing points in outdoor switchyards. It is proposed that earthing points be established where necessary and be located to enable the application of earths

without the use of ladders. This will make the application of earths easier and safer. The exact scope of the work required has yet to be defined so the estimated cost is just a preliminary allocation.

6.6.5 Distribution

The following outlines proposals for network-wide upgrades.

6.6.5.1 Distribution Lines

A feeder rating is the minimum of its circuit breaker rating, outgoing cable rating, or CT thermal rating. Some feeders have constraints beyond the outgoing cable. Feeders are not permitted to exceed their rating. The main HV feeders that have reached or are reaching their load limits are programmed for upgrade or further investigation. Comments on the proposals to address these issues are provided below.

Wanaka

New Wanaka Feeder 2751 - It is not possible to fully off load WK2758 during peak load times. In the 2011 plan it was proposed that a HV connection with WK2752 to be installed during 2011/12. The proposed "Three Parks" development prompted a review of this project and it is now proposed a new Wanaka feeder be established using the existing WK2751 circuit breaker. See development report DR124 for further analysis, although verification of cost estimates are now required. This new feeder will supply the Three Parks area and provide an intertie with Feeders WK2758 and WK2756. The approximate route of the new feeder is shown in Figure 6.25

New Wanaka Feeder 2757 - In the 2011 AMP it was proposed to establish a new feeder in 2013 to facilitate the off-loading of WK 2753. A review of the project has resulted in the project being split into two stages, with stage one implemented in 2013/14 and stage two in 2016/17. See Figure 6.26 for proposed cable route and refer to development report DR135 for additional detail. Further assessment of the loading on this feeder is being carried out in 2013/14 to verify requirements.

Maungawera

Upgrade of Maungawera Feeder to Devon Dairy - As the Devon Dairy development expands, it will be necessary to upgrade the 11 kV lines between the Maungawera zone substation and the development to avoid excessive volt drop. It is estimated the upgrade will be required when the Devon Dairy demand reaches 1 MVA. See Figure 6.27 for the line route. See development report DR126 for further details.



Figure 6.25 - Location of tie cable between WK2756 and WK2752



Figure 6.26 - Route of new Wanaka 2757 feeder.



Figure 6.27 - Route of line upgrade to Devon Dairy Development

Cromwell

New Cromwell Feeder - It is not possible to fully offload CM831 at peak load times. A new feeder will be required in the future to facilitate the off-loading of CM823 and CM831. A new circuit breaker will be required to be installed at the Cromwell zone substation, however further appraisal and detailed design for this project is necessary in 2013/14 to verify the proposed expenditure requirements.

Tarras Irrigation Scheme - The proposed Tarras irrigation scheme requires the installation of a new series of substation and interconnecting feeders, both overhead and underground. An assessment of the additional HV distribution required for this scheme was carried out in 2012 (see Development Reports DR133 and DR133A for a detailed analysis). As at Feb 2013, a decision on the proposal was still pending. Also see section 6.5.5.

Willowbank

The only tie with WB2 is with WB8. The load on both these feeders has been steadily increasing and it is not possible to fully off load WB2 at peak load times. An appraisal is yet to be carried out to identify an economic solution to this constraint.

Neville Street

NS5 can only be off loaded onto NS1 or NS12. Neither of these feeders can take the entire load of NS5. It is proposed that an air break switch be installed in Maryhill Terrace near Avoca Street that will enable the NS5 load to be split between NS1 and NS12.

Queenstown

QT 5232 has just reached its off-load limit an additional intertie with feeder QT 5242 close to switch 551 would facilitate offloading. QT 5262 is also approaching its load limit but no action is proposed at present; however this is being monitored. In the future, an additional intertie with feeder QT 5242 close to switch 555 would facilitate off-loading.

Conversion of 6.6 kV Feeders to 11 kV

Aurora has adopted a long-term strategy of converting its entire 6.6 kV network to 11 kV. This could take 25 to 40 years to complete. This requires new distribution transformers installed on the Aurora 6.6 kV network be dual ratio units. The additional cost for dual ratio transformers is approximately 20%. See section 6.6.8 for further detail.

6.6.6 Distribution Cables (HV)

Undergrounding in SH6

NZTA has been considering, for some time, roading modifications in SH6 between Glenda Drive and Frankton that will require overhead lines in the area to be moved. It is understood that this project will be driven, at least in part, by the development of QLDC's proposed bypass road across Frankton Flats. QLDC announced in December 2012 that it had triggered compulsory land acquisition proceedings under the Public Works Act.

The only practical option for moving the works, as the scope is understood at this time, is to place them underground. It is proposed that additional cables be installed with this project to accommodate load growth to secure space in the road reserve and to avoid future trenching in this very busy section of highway. See development report DR74 for details. The details and timing of this project is in the hands of NZTA which has yet to commit to design of the proposed Glenda Drive roundabout. It is likely that the land acquisition process will be lengthy. An allowance of \$500,000 for the 2013/14 year and estimates will be refined when the scope of the works is defined.

Overhead to Underground Conversion Projects

Aurora has a policy of assisting local authorities to have overhead lines placed underground. In the Dunedin area this work is fully funded by Aurora. In other areas Aurora will contribute dollar for dollar up to an annual maximum equal to 2% of the annual line charges obtained from consumers in the local authority area.

Each year the budgets are adjusted to match the actual distribution line income received in the previous financial year. It has been assumed that line charge rates will increase by 1% per year. The projected expenditure by Aurora is detailed in Section 6.7.

6.6.7 Distribution Switchgear

In the 2012 AMP, a schedule of HV feeder recloser projects was presented, which proposed renewing 2-3 reclosers per year over the next 3 years at a cost of approximately \$50,000 each. This programme will proceed as planned.

6.6.8 Distribution Transformers

Aurora has extensive 6.6 kV distribution in the Dunedin area and small amount in the Clyde Earnsclough area. 6.6 kV is an obsolete distribution voltage and all modern HV distribution equipment has a minimum rating of 11 kV. A circuit operating at 11 kV can deliver 1.67 times the power it can deliver at 6.6 kV. If a circuit is voltage constrained it can deliver 2.7 times the maximum 6.6 kV power if operated at 11 kV. When 6.6 kV zone substations are upgraded replacement transformers with both 6.6 kV and 11 kV capability may be installed.

For consumer initiated projects where dual ratio transformers are required, Aurora will fully fund the additional cost of dual ratio transformers. An allowance of \$80,000 per year has been made for this. See development report DR65 for further detail.

6.6.9 Distribution Substations

Underground Substations

In Dunedin, there are 19 underground substations. In 2005, a significant rainfall event resulted in flooding at five of these substations. Six substations have been fitted with ducting and forced ventilation to mitigate the risk of flooding in the future. It was previously proposed to continue with the waterproofing work on two substations per year however a review of the approach for mitigating this risk is being carried out in 2013/14 to re-evaluate the proposed works required. This review will verify the solutions and required expenditure for 2014/15.

6.6.10 Low Voltage (LV)

No significant new capital/upgrade projects have been identified in this AMP for this asset category, with the exception of customer connections detailed below.

Customer Connections

Network connections can range from a 60A single phase connection to a large industrial connection or a big subdivision of several thousand kVA. To facilitate the connection of customers to the network, new customer connections cover the cost of the extensions to the Aurora network. Customers make a contribution toward the cost of this work in accordance with the Aurora capital investment policy. The creation of new connections and hence expenditure for these is entirely customer driven and subject to regional economic activity. Aurora anticipates that the level of subdivision work in Dunedin for 2013 will not significantly change from status quo; and in Central likely to continue as is at a steady pace. However a review of the drivers and forecasts for customer connections is required and may lead to some readjustments to the annual budgeted expenditure. At present, the forecast for customer connections is illustrated in Table 6.16. The budgeted annual expenditure is presented in Section 6.7.

Table 6.16 - Forecast Consumer connections

ALL NETWORK AREAS							
	2013	2014	2015	2016	2017	2018	2019
Combined Total	84380	85388	86400	87409	88418	89427	90443
DUNEDIN NETWORK							
Dunedin Total	54127	54407	54686	54963	55241	55517	55800
CENTRAL NETWORK							
Central Total	30159	30878	31601	32320	33042	33761	34484
HERITAGE (Te Anau) NETWORK							
Te Anau Total	94	103	113	126	135	149	159

6.6.11 Secondary Assets

System Control and Communication Projects

A review has been carried out on Aurora's communications systems that support protection signaling, SCADA systems and load management systems. A series of recommendations have been put forward covering fibre, voice radio, SCADA, load control, protection communications and disaster recovery. The recommendations identify areas where further investigation is required and suggest options to be considered for further economic analysis and subsequent cost estimation.

In 2011/12 AMP identified that additional investment in communication systems was likely and an initial allowance of \$1 million a year for three years starting 2013/14 was made. Subsequently, the recommendations have been further assessed in order to verify the scope, feasibility and economics for the options and solutions being proposed. Seven key projects make up an overall programme for Aurora's SCCP systems and these are presented in Section 5.6.18 and Table 5.10.

6.7 Capital Expenditure Forecasts

Capital expenditure is split into seven main categories, as per the new Electricity Distribution (Information Disclosure) Requirements 2012. The main plans and projects related to each of these categories were discussed in sections 5 and 6. The tables below show proposed expenditure against each asset category¹⁴.

SYSTEM GROWTH (\$000)										
Asset Category	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Subtransmission	120	1,330	2,250	-	-	-	260	2,340	-	-
Zone substations	5,420	4,420	3,725	5,055	3,355	3,150	3,675	7,725	1,350	1,350
Distribution and LV Lines	262	378	-	-	-	-	-	-	-	-
Distribution and LV Cables	450	3,025	1,025	-	-	-	-	-	-	-
Distribution substations & transformers	692	1,180	1,180	1,180	1,180	1,180	1,180	1,180	1,100	1,100
Distribution Switchgear	-	-	90	-	-	-	-	-	-	-
Secondary Assets/Other	-	-	-	-	-	-	-	-	-	-
Total	6,944	10,333	8,270	6,235	4,535	4,330	5,115	11,245	2,450	2,450
ASSET REPLACEMENT & RENEWAL (\$000)										
Asset Category	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Subtransmission	2,100	200	1,800	390	3,800	2,960	3,570	3,780	-	-
Zone substations	-	900	8,100	900	-	-	-	-	-	-
Distribution and LV Lines	3,000	3,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Distribution and LV Cables	150	150	150	150	150	150	150	150	150	150
Distribution substations & transformers	370	370	370	370	370	370	370	370	370	370
Distribution Switchgear	366	146	96	96	96	96	36	36	36	36
Secondary Assets/Other	1,263	1,945	1,729	3,538	2,558	455	126	0	0	0
Total	7,249	6,711	13,325	7,444	8,974	6,031	6,252	6,336	2,556	2,556
GRAND TOTAL	14,193	17,044	22,195	13,679	13,509	10,361	11,367	17,581	5,006	5,006

¹⁴ Constant pricing capital expenditure was inflated to reflect forecast nominal prices from CPI growth data 2013/14 – 2016/17 sourced from the New Zealand Treasury Half Year Economic and Fiscal Update (Dec 2012). The Treasury CPI growth value from 2016/17 was taken to calculate nominal pricing over 2017/18 – 2022/23 in lieu of available forecast data for this period.

7 Improvement Planning & Programme

7.1 Introduction

The value of assets, maintenance required and proposed capital expenditure outlined in the previous sections of this AMP mean that it is important for Aurora to ensure that asset management practice is aligned with best practice and is always 'forward-looking' when it comes to improvement in practices and standards. In response to this, an asset management improvement programme (AMIP) is being implemented. This improvement programme contains SMART objectives and is aligning with best practice by following the internationally accepted PAS55 standards and utilising the International Infrastructure Management Manual (IIMM) as a guiding document.

The improvement programme covers 'process', 'people' and 'metric' aspects based on the Commerce Commissions assessment framework (Asset Management Maturity Assessment Tool or AMMAT). This framework identifies 31 asset management functional areas based on PAS55.

'Process and people' improvements relate to how Aurora carries out asset management across the range of functional areas, plus the associated capabilities and competencies for achieving asset management objectives. 'Metric' improvements relate specifically to achievement of service levels (asset and customer) and performance targets.

The approach for monitoring progress and measuring success is as follows:

- Process & People improvements - co-ordinated and implemented as per the AMIP action plan; and progress is measured and reported as per the AMMAT (see Section 7.3).
- Metric improvements – asset management monitored and measured against defined Levels of Services and Performance Measures/KPI's (see Section 3). Physical improvements in the network that relate to these are outlined in Sections 5 and 6.

Three key aspects have been used to plan and develop the framework and actions for the AMIP. These are: (i) initial gap analysis; (ii) determination of target level for asset management practice; and (iii) identification of improvement areas. These are discussed in the following sections.

7.2 Gap Analysis

Key to achieving Aurora's asset management outcomes is assessing and understanding;

- (i) Where Aurora currently sits of the asset management maturity continuum i.e. its current level of asset management practice (in relation to alignment with PAS55);
- (ii) What the appropriate level of asset management practice is within the context of Aurora's business; and therefore
- (iii) Areas where changes to asset management processes and practice would produce improvements in financial performance, risk management and asset performance.

An initial gap analysis based on PAS 55 was undertaken in 2011. The outputs from this provided appropriate baseline indication of asset management maturity across a range of functional areas. Complimentary to this, an assessment was carried out to determine the appropriate level of asset management practice that should be targeted for the future. This assessment comprised of two phases:

- (i) A desk-top assessment to establish the over-arching target for asset management practice within the context of Aurora's business.
- (ii) An assessment of each asset management functional area in order to assign a specific target level so that monitoring of progress can be more easily facilitated.

These assessments have established a picture of the "current situation" and "required/targeted future state". The 'gap' in-between has provided focus for a framework to produce the AMIP and associated action plan.

Stages of asset management maturity range from minimum/basic to advanced (0-4) and a general description of these is provided in Table 7.1. Overall, Aurora's target level for asset management maturity is Intermediate-to-Advanced.

Aurora is committed to achieving alignment with best practice asset management that is fit-for-purpose and as such is aiming for a maturity target level of practice ranging from 3 – 4 across the main functional areas of asset management.

Table 7.1 - Asset Management Maturity index

Maturity Level	PAS 55 Criteria	Description
Minimum	0-1 ↓	Basic technical approach undertaken at a level designed to meet <u>minimum</u> regulatory and organisational requirements for asset management, financial planning and reporting. Provides rudimentary guidelines and outputs to help inform some functional areas of asset management. Understanding of the elements required by best practice asset management is minimal. The organisation is in the process of developing a common understanding of these.
Core	2 ↓	Builds on basic technical approach, acquiring more technical information and increasing improvements. Development of approaches and practices across all functional areas of asset management. Some risk management; limited automated analysis. The organisation has a basic understanding of the requirements of best practice. It is in the process of deciding how the elements of best practice will be applied and has started to apply them.
Intermediate	3 ↓	Builds on 'core' practice plus more robust asset management techniques with improved maintenance management. Frequent use of risk-based approaches/risk management & asset lifecycle management, with more automated analysis. Understands key assumptions and uncertainties. Has started to develop and establish decision-making techniques based on ODM. The organisation has a good understanding of best practice requirements. It has decided how the elements of best practice will be applied and work is progressing on implementation.
Advanced	4	Builds on 'intermediate' practice with optimization of systems, activities, programmes to meet current and future LoS. Advanced and integrated AM, with mature collection and analysis processes for key asset information, risk, costs and treatment options; enabled through robust improvement framework for development of capabilities, technologies and practices. All elements of best practice are in place and are being applied and are integrated. Only minor inconsistencies may exist. Relevant ISO certifications achieved. Some processes and approaches may go beyond requirements, pushing the boundaries of asset management to develop new concepts and ideas.

7.3 Asset Management Maturity Assessment Results

Figure 7.1 illustrates Aurora's progress since 2011 for improving asset management process and practice.

The results show that there has been steady improvements made across all aspects of Aurora's asset management since the initial baseline assessment was carried out in 2011.

The areas that have shown greatest improvement to date are:

- systems and information management
- structure and capabilities
- communication/participation

It is clear that these results demonstrate the effects of a targeted strategy for asset management improvement within Aurora's asset management service providers, Delta.

The areas that will be receiving attention in 2013/14 are:

- asset strategy and delivery
- documentation, controls and review
- competency and training

and asset systems and information will continue to be refined

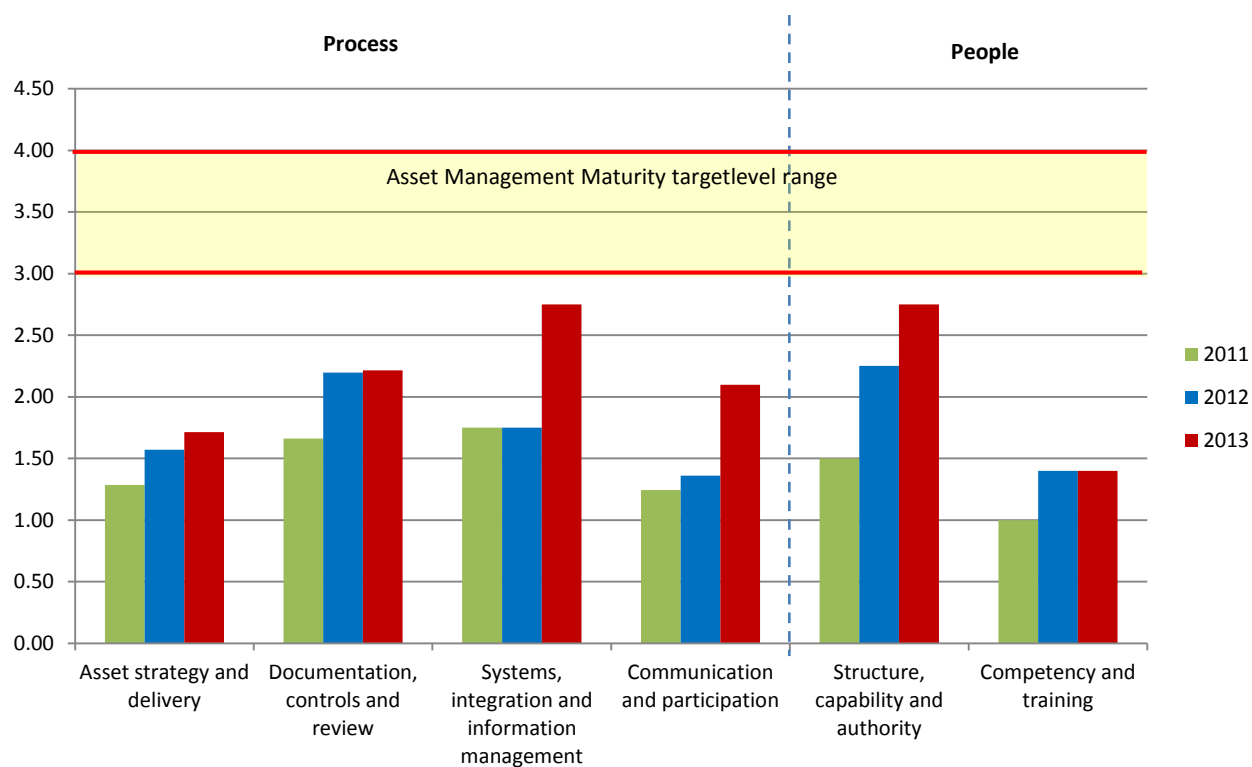


Figure 7.1 – Asset Management Maturity Assessment results (2010-2013)

Figure 7.2 provides a detailed view on the results from the 2012/13 assessment. Further detail is provided in Appendix F. Recommended improvements from this assessment are being incorporated into the improvement programme. The following section contains further detail on this.

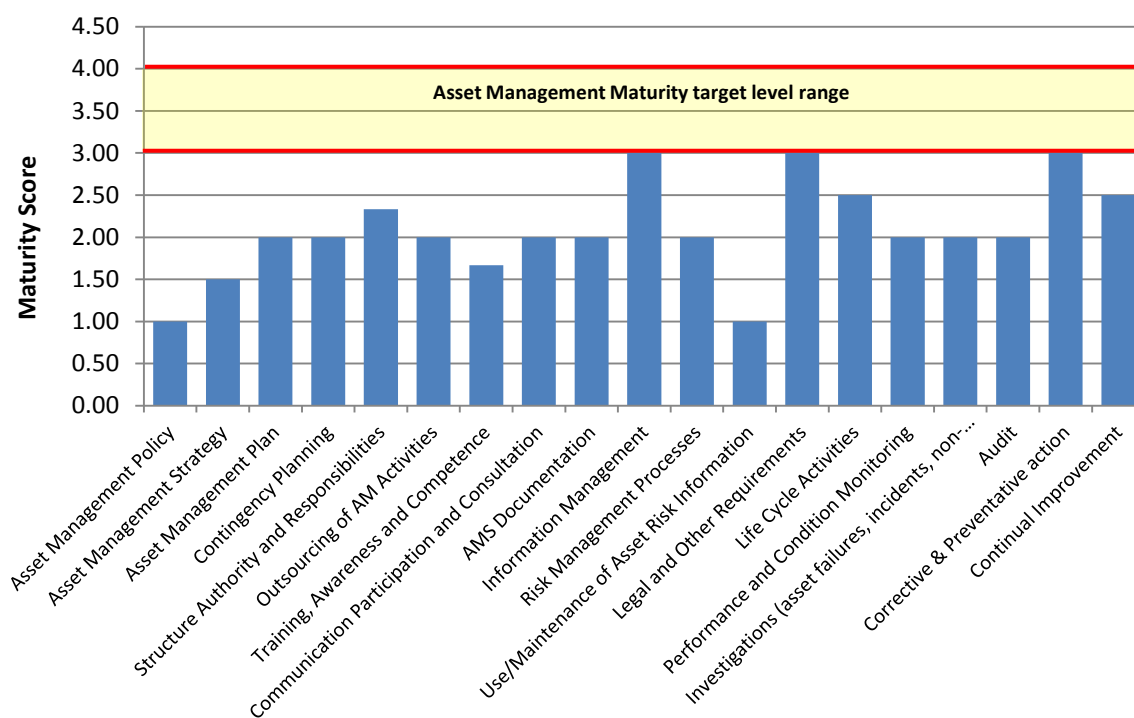


Figure 7.2 – Asset Management Maturity assessment results 2012/13.

7.4 Improvement Programme

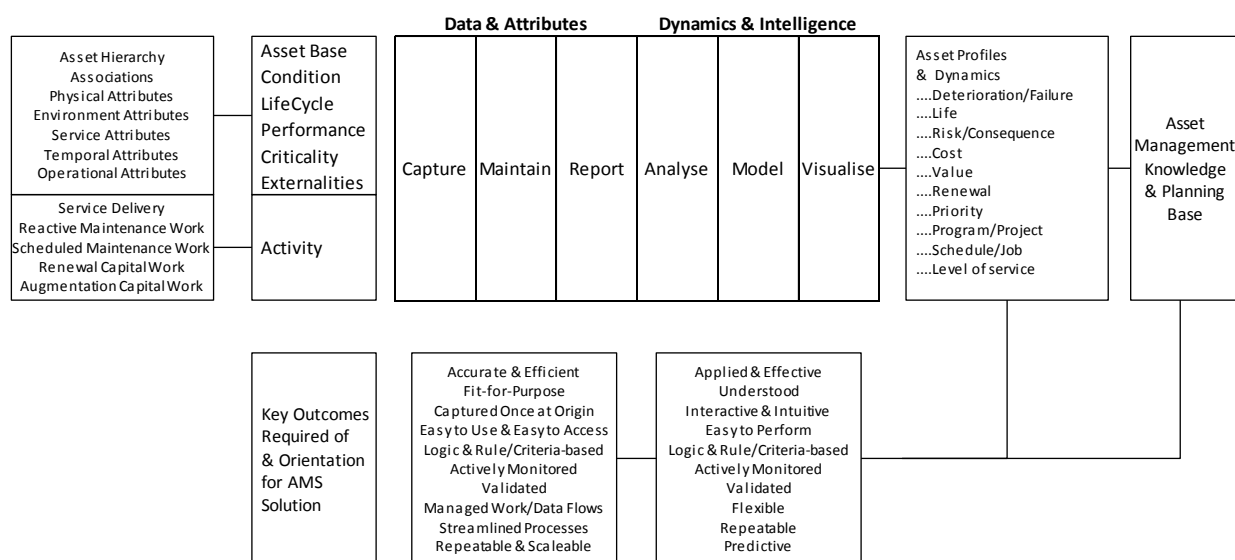
Aurora's improvement programme aims to address the gaps identified within each of these functional areas. This is a significant undertaking being the first overhaul of the underlying asset management practices for a number of years. The text below outlines the planned initiatives for the areas requiring attention as outlined in Section 7.3, being: Asset Strategy and Delivery; Documentation, Controls and Review; Competency and Training. Aurora also intends to continue to focus on developments for Asset Systems and Information. Further detail is contained in the Aurora's AMIP and action plan, as well as the AMMAT assessment provided as part of Information Disclosure on Aurora's website.

Asset Strategy and Delivery

Asset Management Policy - A draft policy has been developed and is in final form, pending any modifications from Aurora's strategic planning exercise. The process of formalising and authorising the Policy will be continued to completion in early 2013.

Asset Management Strategy - the AMIP sets out a number of work-streams with actions to ensure that the asset management strategy is consistent with wider policies and strategies. Work-streams are in progress to ensure that the asset management strategy and policy are aligned to the pending revision of Aurora's business strategy. Regular customer surveys are also undertaken, and are in the process of being reviewed to confirm that the strategy is consistent with needs of stakeholders; and to ensure that the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship is taken into account appropriately.

In addition, the policy and strategy outcomes and priorities also provide the direction for the development and improvement of enabling and supporting asset management information systems, processes and practices. The diagram below examples the main aspects and dimensions being considered under the asset management system review framework.



Opportunities

During 2012, progress on opportunities for improvements has focussed upon:

- building more quality assurance approaches into existing processes and practices to improve the completeness, currency and appropriateness of data
- commencing an "augmented intelligence" approach to the processing of data to generate value-add insights into business dynamics and performance.
- commencing the investigation of cost effective, value-add technology solutions to support and enable business go forward.

Developments in the information, communication and technology sector (ICT) provide opportunity for Aurora to consider introduction for increased levels of intelligence and performance. Emergent and proven technologies, coupled with decreasing relative technology costs, provide economically viable opportunities to better enable and support more efficient and effective asset management. Smart, easy to use and cost effective solutions will be tested in terms of their ability to enable and support :

Improved operational performance through

- capture of data once only at point of origin
(often mobile in the field)
- more efficient and robust data capture
(under a rule-based, validated process)
- improved situational awareness
(with real-time/near real-time data)
- better responsiveness

Reduced hand-offs Reduced duplication Right first time Reduced administrative overhead Improved response times
--

Improved strategic performance through

- more systems based approach to analysis
(making the data work hard)
- common, standards based approaches
- more easily repeatable and transferable
(cascading across processes and asset types)
- improved business knowledge
(augmented intelligence, data works hard)
- more informed planning and decision-making

Data made to work hard Improved repeatability Reduced duplication Right first time Reduced administrative overhead
--

A number of pilot trials of solution opportunities are planned to be progressed. Opportunities will be tested against a range of operational, tactical and strategic outcomes, including :

- implementing easy to use solutions
- reducing administrative burdens
- streamlining end-to-end processes
- facilitating the flow of information
- reducing cycle times
- improving resolution rates
- increasing productivity
- mitigating risk
- reducing lifecycle costs

Documentation, Controls and Review

While the number of policies, plans, processes and procedures for managing Aurora's network is extensive and annual audits and compliance reviews are carried out, many of the practices have not been revisited against internationally accepted practice for many years.

While, Aurora has quality management processes and procedures in place to ensure any non-compliance issues are addressed systematically, review of the quality management system has highlighted areas for improvement, which are now the focus for 2013/14. For example, identification of legislative and regulatory changes occurs relatively informally and risks around authorised materials and products exist (however a review of the materials purchasing and storage/supply is currently being carried out). A structured framework for managing the existing business systems and quality documentation is being implemented in 2013/14.

Use of asset risk information

Implementation of the revised risk assessment and management framework in 2013/14 will build a more robust risk-based approach to decision making and bring improvements to the use and maintenance of asset risk information and reporting. In conjunction, procedures for assessing asset condition are being reviewed; for example pole condition now includes wider features such as location sensitivity and customer criticality. A major work-stream involves not simply tinkering with inspection processes but questioning the fundamental basis of the processes. This will require an extensive review across all assets and will continue with power transformers and ground-mounted switchgear.

Competency and Training

Core competency framework and development plans are being refined and retention of core engineering skills is recognised as key. The intention is for the improvement programme outputs to be used to identify emerging skill and competency requirements and drive co-ordinated training programmes.

7.4.1 Improvement Programme Monitoring

The AMIP action plan will be monitored and reviewed against SMART objectives and updated on an annual basis. The AMIP will then be adjusted accordingly (demonstrating an iterative cycle of continuous improvement), taking into account overall progress, changing business priorities, risks and affordability.

7.4.2 Summary

A formal review of asset management maturity, in advance of any stipulation by the Commerce Commission, identified the need to extensively revisit and upgrade the practices of asset management employed in managing the Aurora network. An AMIP has been established to guide implementation of processes, systems and capability referenced to internationally accepted methods. Many of the necessary structures are in early stages of definition with the detailed work of critically understanding the assets having commenced. Previously identified reinvestment in the Aurora network continues in parallel with the AMIP. Details of the extent of this work is described elsewhere in this Plan.

Glossary of Terms

ABS	Air break switch
ACSR	Aluminium conductor steel reinforced
ADMD	After diversity maximum demand
AMP	Asset Management Plan
AUFLS	Automatic Under Frequency load shedding
CAIDI	Customer average interruption duration index
CB	Circuit breaker
CPD	Congestion Period Demand
CAIDI	Consumer average interruption duration index
CODC	Central Otago District Council
DC	Direct current
DCC	Dunedin City Council
DGA	Dissolved gas analysis
DRC	Depreciated replacement cost
DSM	Demand side management
GIS	Geographical Information System
GPD	Group Peak Demand
GWh	Gigawatt hour
GXP	Grid exit point
HV	High voltage
HWB	Halfway Bush
Hz	Hertz
ICP	Installation control point
IEDs	Intelligent electronic devices
IEEE	Institute of Electrical and Electronic Engineers
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt
LV	Low voltage
MDIs	Maximum demand indicators
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt (one million watts)
ODV	Optimised deprival value/valuation
ORC	Otago Regional Council
PILC	Paper insulated lead cable
pf	Power factor
PV	Photo voltaic
QLDC	Queenstown-Lakes District Council
RC	Replacement cost
SAIDI	System average interruption duration index (minutes) (= sum of number of interrupted customers x interruption duration) / total number of customers
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition System
SF6	Sulphur hexafluoride
SWER	Single wire earth return. The Aurora network has one SWER line that supplies the Pigeon Flat area of Dunedin.
V	Volt
XLPE	Cross linked polyethylene cable

Appendix A.1- Interruption and Duration Forecast

Company Name

Aurora Energy Limited

AMP Planning Period

1 April 2013 – 31 March 2023

Network / Sub-network Name

Aurora Energy Limited

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
	for year ended:	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
8	SAIDI						
9	Class B (planned interruptions on the network)	14.0	14.0	14.0	13.0	13.0	13.0
10	Class C (unplanned interruptions on the network)	70.0	68.0	68.0	68.0	67.0	67.0
11	SAIFI						
12	Class B (planned interruptions on the network)	0.12	0.12	0.12	0.11	0.11	0.11
13	Class C (unplanned interruptions on the network)	1.22	1.25	1.24	1.24	1.22	1.22

Appendix A.2 - Report on Asset Condition

		Company Name	Aurora Energy Limited						
		AMP Planning Period	1 April 2013 – 31 March 2023						
SCHEDULE 12a: REPORT ON ASSET CONDITION									
This schedule requires a breakdown of asset condition by asset class at the start of the forecast year. The data accuracy assessment relates to the percentage values declared in the asset condition column. 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 length.									
Asset condition at start of planning period (percentage of units by grade)									
Valtag Asset category	Asset class	Unit	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5
All	Overhead Line	Concrete pole/steel structure	Na.	0.40%	0.10%	3.10%	96.30%	-	3
All	Overhead Line	Wood pole	Na.	4.00%	2.20%	55.00%	39.10%	-	3
All	Overhead Line	Other pole types	Na.	0.60%	0.20%	25.00%	74.30%	-	3
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	18.00%	16.70%	4.70%	60.60%	-	3
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km					N/A	
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	100.00%	-	2
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurized)	km	-	-	-	100.00%	-	3
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurized)	km	-	-	-	100.00%	-	3
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.00%	-	3
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km					N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurized)	km					N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas pressurized)	km					N/A	
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km					N/A	
HV	Subtransmission Cable	Subtransmission submarine cable	km					N/A	
HV	Zonesubstation Building	Zonesubstation up to 66kV	Na.	14.80%	7.40%	7.40%	70.40%	-	3
HV	Zonesubstation Building	Zonesubstation 110kV+	Na.	-	-	-	-	N/A	
HV	Zonesubstation switchgear	22/33kV CB (Indoor)	Na.	-	-	-	-	-	3
HV	Zonesubstation switchgear	22/33kV CB (Outdoor)	Na.	45.70%	-	11.40%	42.90%	-	3
HV	Zonesubstation switchgear	33kV Switch (Ground Mounted)	Na.	-	-	-	-	N/A	
HV	Zonesubstation switchgear	33kV Switch (Pole Mounted)	Na.	40.70%	1.00%	-	58.20%	-	3
HV	Zonesubstation switchgear	33kV RMU	Na.	-	-	-	-	N/A	
HV	Zonesubstation switchgear	50/66/110kV CB (Indoor)	Na.	-	-	-	-	N/A	
HV	Zonesubstation switchgear	50/66/110kV CB (Outdoor)	Na.	-	-	-	100.00%	-	3
HV	Zonesubstation switchgear	3.3/6.6/11/22kV CB (ground mounted)	Na.	26.00%	6.90%	2.70%	64.40%	-	3
HV	Zonesubstation switchgear	3.3/6.6/11/22kV CB (pole mounted)	Na.	59.30%	-	-	40.70%	-	3
Asset condition at start of planning period (percentage of units by grade)									
Valtag Asset category	Asset class	Unit	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5
HV	Zonesubstation Transformer	Zonesubstation Transformer	Na.	-	-	3.00%	97.00%	-	3
HV	Distribution Line	Distribution OH Open Wire Conductor	km	5.70%	3.50%	3.40%	87.40%	-	3
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	N/A	
HV	Distribution Line	SWER conductor	km	-	-	65.80%	34.20%	-	3
HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	100.00%	-	1
HV	Distribution Cable	Distribution UG PILC	km	-	-	-	100.00%	-	1
HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	100.00%	-	1
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalizers	Na.	-	-	-	100.00%	-	4
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	Na.	64.70%	-	-	35.30%	-	2
HV	Distribution switchgear	3.3/6.6/11/22kV Switchgear and fuses (pole mounted)	Na.	13.10%	5.00%	4.10%	77.80%	-	4
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	Na.	23.20%	5.90%	3.90%	67.00%	-	2
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	Na.	0.40%	2.10%	5.40%	92.00%	-	3
HV	Distribution Transformer	Pole Mounted Transformer	Na.	3.70%	2.20%	3.20%	90.90%	-	3
HV	Distribution Transformer	Ground Mounted Transformer	Na.	-	0.37%	0.45%	99.20%	-	3
HV	Distribution Transformer	Voltage regulators	Na.	2.70%	-	-	97.30%	-	4
HV	Distribution Substation	Ground Mounted Substation Housing	Na.	2.00%	2.40%	2.40%	93.20%	-	2
LV	LV Line	LV OH Conductor	km	6.60%	2.40%	1.90%	89.00%	-	3
LV	LV Cable	LV UG Cable	km	0.30%	0.50%	1.30%	97.90%	-	1
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	5.20%	3.10%	5.30%	86.40%	-	2
LV	Connections	OH/UG consumer service connections	Na.	30.10%	4.60%	3.00%	62.30%	-	1
All	Protection	Protection relays (electromechanical, solid state and numeric)	Na.	-	-	-	-	-	1
All	SCADA and communication	SCADA and communication equipment operating or sizing	Lat	-	-	-	-	-	1
All	Capacitor Bank	Capacitors including controls	Lat	-	-	-	-	-	1
All	Load Control	Controlled plant	Lat	-	-	-	-	-	1
All	Load Control	Relays	Lat	-	-	-	-	-	1
All	Civil	Cable Tunnel	km	-	-	-	-	-	1

Appendix A.4 - Expenditure Forecasts

Company Name

Aurora Energy Limited

AMP Planning Period

1 April 2013 – 31 March 2023

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 reporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. EDOs 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.

		Current Year											
		for year ended	CY	CY1	CY2	CY3	CY4	CY5	CY6	CY7	CY8	CY9	CY10
			31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
1	Operational Expenditure Forecast		1000 (in constant dollars)										
2	Service integrity and emergency		1,541	1,540	1,541	1,540	1,541	1,540	1,541	1,540	1,541	1,540	1,541
3	Vegetation management		1,209	1,210	1,209	1,210	1,209	1,210	1,209	1,210	1,209	1,210	1,209
4	Roads and corrective maintenance and inspection		2,208	2,209	2,208	2,209	2,208	2,209	2,208	2,209	2,208	2,209	2,208
5	Asset replacement and renewal		1,963	1,964	1,963	1,964	1,963	1,964	1,963	1,964	1,963	1,964	1,963
6	Network Opex		5,921	5,923	5,922	5,923	5,922	5,923	5,922	5,923	5,922	5,923	5,922
7	System operations and network support		505	505	505	505	505	505	505	505	505	505	505
8	Business support		275	275	275	275	275	275	275	275	275	275	275
9	Non-network opex		292	293	292	293	292	293	292	293	292	293	292
10	Operational expenditure		16,483	16,502	16,488	16,513	16,477	16,543	16,493	16,590	16,493	16,847	16,944
			1000 (in constant prices)										
11	Service integrity and emergency		1,541	1,540	1,541	1,540	1,541	1,540	1,541	1,540	1,541	1,540	1,541
12	Vegetation management		1,209	1,210	1,209	1,210	1,209	1,210	1,209	1,210	1,209	1,210	1,209
13	Roads and corrective maintenance and inspection		2,208	2,209	2,208	2,209	2,208	2,209	2,208	2,209	2,208	2,209	2,208
14	Asset replacement and renewal		1,963	1,964	1,963	1,964	1,963	1,964	1,963	1,964	1,963	1,964	1,963
15	Network Opex		5,921	5,923	5,922	5,923	5,922	5,923	5,922	5,923	5,922	5,923	5,922
16	System operations and network support		505	505	505	505	505	505	505	505	505	505	505
17	Business support		275	275	275	275	275	275	275	275	275	275	275
18	Non-network opex		292	293	292	293	292	293	292	293	292	293	292
19	Operational expenditure		16,483	16,502	16,488	16,513	16,477	16,543	16,493	16,590	16,493	16,847	16,944
20	Subcomponents of operational expenditure (where known)												
21	Energy efficiency and demand side management, reduction of energy losses												
22	Direct billing												
23	Research and Development												
24	Other												
25	Other												
26	Other												
27	Other												
28	Other												
29	Other												
30	Other												
31	Other												
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94	Other												
95	Other												
96	Other												
97	Other												
98	Other												
99	Other												
100	Other												

Company Name

Aurora Energy Limited

AMP Planning Period

1 April 2013 – 31 March 2023

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast capital expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the reporting 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 commingled assets (i.e., the value of RAB additions). EDOs must provide explanatory comment on the difference between constant price and nominal dollar forecast of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). This information is not part of audited disclosure information.

		Current Year											
		for year ended	CY	CY1	CY2	CY3	CY4	CY5	CY6	CY7	CY8	CY9	CY10
			31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
1	11a(i): Expenditure on Assets Forecast		1000 (in constant dollars)										
2	Consumer connection		5,000	5,002	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
3	System growth		308	3,082	10,858	6,882	6,372	6,438	6,428	6,222	11,492	2,484	2,484
4	Asset replacement and renewal		9,432	7,707	6,059	14,221	7,600	6,967	6,464	6,340	6,475	2,410	2,410
5	Asset relocation		5,001	5,000	5,004	5,004	5,002	5,000	5,004	5,000	5,000	5,000	5,000
6	Reliability, safety and environment												
7	Quality of supply		400	2,000	651	327	307	204	204	204	204	204	204
8	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
9	Other reliability, safety and environment		187	723	1,488	480	40	307	153	153	153	153	153
10	Total reliability, safety and environment		187	723	1,488	480	40	307	153	153	153	153	153
11	Expenditure on network assets		17,439	28,107	27,409	26,102	22,699	22,792	20,600	21,684	27,030	16,014	16,111
12	Non-network assets		-	-	-	-	-	-	-	-	-	-	-
13	Expenditure on assets		17,439	28,107	27,409	26,102	22,699	22,792	20,600	21,684	27,030	16,014	16,111
14	Capital expenditure forecast												

11a(iii): System Growth

11a(iv): Asset Replacement and Renewal

11a(v):Asset Relocations

11a(vi):Quality of Supply

11a(vii): Legislative and Regulatory

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		Current Year CY ¹	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
11a(viii): Other Reliability, Safety and Environment¹		\$000 (in constant prices)					
<i>Project or programme*</i>							
Establish Earthing Points at Central zone substations		50	-	-	-	-	-
Transformer Buchholz relays at Dun zone subs		30	30	30	30	-	-
Replacement of oil-filled switchgear		-	80	120	120	120	120
SCCP P6 - DND Subtransmission network protection		65	380	860	320	-	180
SCCP P7 - Aurora ICCP System		10	220	120	-	-	-
<i>Include additional rows if needed</i>							
All other reliability, safety and environment projects or programmes							
Other reliability, safety and environment expenditure		155	710	1,130	470	120	300
<i>less</i> Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		155	710	1,130	470	120	300
11a(ix): Non-Network Assets							
Routine expenditure							
<i>Project or programme*</i>							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
<i>Include additional rows if needed</i>							
All other routine expenditure projects or programmes							
Routine expenditure		-	-	-	-	-	-
Atypical expenditure							
<i>Project or programme*</i>							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
<i>Include additional rows if needed</i>							
All other atypical projects or programmes							
Atypical expenditure		-	-	-	-	-	-
Non-network assets expenditure		-	-	-	-	-	-

Appendix A - SAIDI, SAIFI, CAIDI performance results

SAIDI	CC year	Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIDI
Actual	2001/02	13.80	61.50	75.30	-	13.4	13.4	88.7
	2002/03	20.50	68.60	89.10	-	12.1	12.1	101.2
	2003/04	16.27	79.98	96.25	-	1.0	1.0	97.3
	2004/05	7.30	73.21	80.51	-	-	-	80.5
	2005/06	11.72	70.80	82.52	-	14.0	14.0	96.5
	2006/07	13.17	83.52	96.69	-	4.7	4.7	101.4
	2007/08	13.29	115.99	129.28	-	11.0	11.0	140.3
	2008/09	8.82	59.15	67.97	-	-	-	68.0
	2009/10	11.17	61.30	72.47	-	10.2	10.2	82.7
	2010/11	16.92	94.62	111.54	-	-	-	111.5
	2011/12	13.4	102.5	115.88	-	-	-	115.8
Target	2012/13	14.0	70.0	84.0	-	-	-	84.0
	2013/14	14.0	69.0	83.0	-	-	-	83.0
	2014/15	14.0	68.0	82.0	-	-	-	82.0
	2015/16	13.0	68.0	81.0	-	-	-	81.0
	2016/17	13.0	67.0	80.0	-	-	-	80.0
	2017/18	13.0	67.0	80.0	-	-	-	80.0
	2018/19	13.0	66.0	79.0	-	-	-	79.0
	2019/20	13.0	65.0	78.0				78.0

SAIFI	CC year	Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIFI
Actual	2001/02	0.17	1.39	1.56	-	0.23	0.23	1.79
	2002/03	0.15	1.36	1.51	-	0.57	0.57	2.08
	2003/04	0.14	1.47	1.61	-	0.11	0.11	1.72
	2004/05	0.07	1.39	1.46	-	-	-	1.46
	2005/06	0.09	1.40	1.49	-	0.23	0.23	1.72
	2006/07	0.10	1.59	1.69	-	0.13	0.13	1.82
	2007/08	0.10	1.37	1.47	-	0.35	0.35	1.82
	2008/09	0.05	1.17	1.22	-	-	-	1.22
	2009/10	0.09	1.25	1.34	-	0.14	0.14	1.48
	2010/11	0.12	1.36	1.48	-	-	-	1.48
	2011/12	0.09	1.70	1.79	-	-	-	1.79
Target	2012/13	0.12	1.27	1.38	-	-	-	1.39
	2013/14	0.12	1.25	1.37	-	-	-	1.37
	2014/15	0.12	1.24	1.36	-	-	-	1.36
	2015/16	0.11	1.24	1.35	-	-	-	1.35
	2016/17	0.11	1.22	1.33	-	-	-	1.33
	2017/18	0.11	1.22	1.33	-	-	-	1.33
	2018/19	0.11	1.20	1.31	-	-	-	1.31
	2019/20	0.11	1.19	1.30				1.30

CAIDI	CC year	Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall CAIDI
Actual	2001/02	81.7	42.2	48.3	-	59.0	58.3	49.6
	2002/03	134.9	48.6	56.6	-	21.3	21.3	47.6
	2003/04	119.9	54.5	60.0	-	8.8	8.8	56.6
	2004/05	100.2	52.9	55.3	-	-	-	55.3
	2005/06	135.7	50.5	55.5	-	60.0	60.0	56.1
	2006/07	127.0	52.9	57.5	-	35.6	35.6	55.9
	2007/08	141.7	84.6	88.2	-	31.4	31.4	77.3
	2008/09	160.5	50.4	55.3	-	-	-	55.3
	2009/10	129.4	49.0	54.2	-	71.0	71.0	55.8
	2010/11	144.5	69.5	75.5	-	-	-	60.3
	2011/12	148.6	77.9	81.5	-	-	15.0	72.0
Target	2012/13	120.0	55.0	60.0	-	-	-	60.0
	2013/14	120.0	55.0	60.0	-	-	-	60.0
	2014/15	120.0	55.0	60.0	-	-	-	60.0
	2015/16	120.0	55.0	60.0	-	-	-	60.0
	2016/17	120.0	55.0	60.0	-	-	-	60.0
	2017/18	120.0	55.0	60.0	-	-	-	60.0
	2018/19	120.0	55.0	60.0	-	-	-	60.0
	2019/20	120.0	55.0	60.0				60.0

Appendix B - Table of Guidelines for Security of Supply

(see Note 1)

Class of Supply	Range of Group Peak Demand (GPD) in MVA	Examples	Minimum Demand to be met after:		
			First Outage (Circuit or Transformer)	Second Outage (Circuit or Transformer)	Bus-bar Fault
URBAN					
U1	0 to 1.0	LV circuits, transformers on HV spur feeds	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil Within repair time 100% GPD (notes 2, 4)	Not applicable
U2	1.0 to 3MVA (6.6kV) or to 5MVA (11kV)	HV feeders	Initially - nil Within switching time 100% GPD	Initially - nil Within repair time 100% GPD (notes 2, 4)	Not applicable
U3	Up to 10 MVA	Small/medium zone substations	Initially - nil Within switching time 100% GPD (note 5)	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil In within switching time 100% GPD (note 7)
U4	Over 10MVA	Larger zone sub-stations	Defined firm capacity	Initially - nil Within repair time 100% GPD (notes 2, 4)	Initially - nil In within switching time 100% GPD (note 7)

Class of Supply	Range of Group Peak Demand (GPD) in MVA	Examples	Minimum Demand to be met after:
			First Outage (Circuit or Transformer)
RURAL			
R1	All	Rural customers (eg fed by a single transformer)	Initially - nil Within repair time 100% GPD (notes 3, 4)
R2	0 to 3 MVA (6.6 kV) or to 5 MVA (11 kV)	Rural radial feeder	Initially - nil Within repair time 100% GPD (notes 3, 4)
R3	0 to 5 MVA	Rural zone substation	Initially nil Within switching time 100% GPD (notes 3, 4)

NOTES:

- 1) This table provides the basic guidelines for supply security; however, in all cases, if the GPD exceeds the given range, any reinforcement expenditure must be justified by economic analysis.
- 2) A target restoration time has been set of 4 hours from notification in urban areas – except under disaster conditions (eg extreme weather).
- 3) A target restoration time has been set of 6 hours from notification in rural areas – except under disaster conditions (eg extreme weather).
- 4) A mobile generator or temporary reticulation may be used to achieve restoration within the target restoration times if time to repair the failed asset is expected to exceed the target time.
- 5) In recognition of the long repair times associated with repairing transformer failures, it is normal practice to install two transformers in all locations where the load exceeds 5 MVA. In the event of a single transformer failure, part of the load will remain on supply - and thus can be regarded as having a full (N-1) security. The remaining load would normally be restored by switching and, thus, is classified as (N-1) switched.
- 6) A mobile substation may be relocated if appropriate to achieve restoration.
- 7) Substations with loads exceeding 5.0 MVA are built with the HV bus-bars split by a bus-coupler and have two transformers (see note 5). If the bus-coupler fails, it is regarded as a double fault situation.

Appendix C - Compliance Matrix

Commerce Commission – Electricity Information Disclosure Requirements 2012 (Appendix A)

CLAUSE	REQUIREMENT	AMP Section	Tables & Figures
Contents of the AMP			
3.1	Asset Management Plan summary	1.0	
3.2	Background and Objectives	2.1	
3.3	Purpose Statement	2.2	Table 2.1
3.4	AMP Planning period	2.4.1	
3.5	Date approved by Directors	Pg. 2	
3.6	Description of Stakeholder Interests 3.6.1 How interests are identified 3.6.2 What these interests are 3.6.3 How the interests are accommodated in AM practices 3.6.4 How conflicting interests are managed	2.3.2 / 3.1 2.3.2 2.4 / 3.3 2.3.2	Table 2.3
3.7	Description of accountabilities and responsibilities for AM	2.3	Table 2.2
3.8	All significant assumptions	2.4 / 2.4.1 6.4-6.6	
3.9	A description of the factors that may lead to material difference	2.4 / 2.4.1 6.6	
3.10	An overview of AM strategy and delivery	2.2-2.6	
3.11	An overview of systems and information management data	2.6	
3.12	Statement on data limitations and proposed improvements	2.6 / 5.0 / 7.0	
3.13	Description of processes used for: 3.13.1 Managing routine inspections and maintenance; 3.13.2 Planning and implementing network development projects; 3.13.3 Measuring network performance	5.5 6.0 3.2	
3.14	An overview of AM documentation, controls and review processes	2.6.2	
3.15	An overview of communication and participation processes	2.6.3	
Assets Covered			
4.1	High level description of the distribution area.	5.2	Table 5.1
4.2	Description of network configuration.	5.2 / 5.3 5.5.3-5.5.20	Tables 5.2 -5.7
Network Assets by Category			
4.4 & 4.5	Description of network assets by category	5.5	Table 5.8
Service Levels			
5.0 - 7.0	Service Levels, Performance Measures and Targets	3.0-3.3	Table 3.9
8.0 - 10	Justification for Target Levels	3.2-3.3	Table 3.9
Network Development Planning			
11	Detailed description of network development plans including: 11.1 & 11.2 Description of the planning criteria and assumptions. 11.3 & 11.4 Description of strategies or processes that promote cost efficiency	2.4 / 6.2 6.2	Appendix D

CLAUSE	REQUIREMENT	AMP Section	Tables & Figures
	11.5 Description of strategies used to promote energy efficient operation of the network 11.6 Description of criteria used to determine capacity of equipment 11.7 The prioritisation methodology adopted for development projects. 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 load increases; including distributed generation and demand management 11.9 Analysis of network development options available and details of the decisions made to satisfy and meet target levels of service. 11.10 Description and identification of the network development programme and actions to be taken, including associated expenditure. 11.11 Distributed generation and related policies. 11.12 Non-network solutions and related policies.	6.2 6.4 6.3 / 6.5 6.6 6.6 6.4 6.2 / 6.3	Appendix D Table 6.13 Appendix E
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12	Detailed description of lifecycle asset management processes including: 12.1 Key drivers for maintenance planning and assumptions 12.2 Description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including expenditure projections. 12.3 Description and identification of asset replacement and renewal policies and programmes or actions to be taken for each asset category, including associated expenditure projections.	5.0 2.4 / 5.5 5.4 – 5.6 5.4 – 5.6	
Non-network development, maintenance and renewal			
13	A summary description of material non-network development.		
Risk Management			
14	Details of risk policies, assessment and mitigation including: 14.1 Methods, details and conclusions of risk analysis 14.2 Strategies used to identify network vulnerabilities (to high impact low probability events) and resilience of the network 14.3 Policies to mitigate or manage risks of events identified in 14.2 14.4 Details of emergency response and contingency plans	4.0 4.4 - 4.6 4.4 - 4.6 4.7 4.7	
Evaluation of performance			
15	Details of performance measurement, evaluation, and improvement including: 15.1 Review of progress against plan, both physical and financial. 15.2 Evaluation and comparison of actual service level performance against targeted performance. 15.3 An evaluation and comparison of the results of asset management maturity assessment. 15.4 Analysis of identified gaps and identification of planned initiatives to address the situation.	3.2 3.2 3.2.1-3.2.7 7.0 – 7.3 7.3 / 7.4	Table 3.2 Figure 7.1 App. F
Capability to Deliver			
16	Describe the processes used to ensure: 16.1 The AMP is realistic and objectives can be achieved 16.2 Organisation structure and processes for authorisation and business capabilities will support implementation of the AMP.	3.4	

Appendix D - Asset Management quality control documentation

Activity	Exiting Documents
Asset Management - general	<p>QM013, Design And Development Activities</p> <p>QN15, Maintenance Policy</p> <p>QN16, Network Operation Policy</p> <p>QN17, Network Connections</p> <p>QN18, Voltage Quality</p> <p>QN19, System Planning</p> <p>QN20, Risk Management For Electricity Networks</p> <p>Connections</p> <p>QP1701A, Capital Investment Approval Process</p> <p>QP1701B, Capital Funding Requests</p> <p>QP1702, Capital Investment Schedules</p> <p>QP1703, Processing Connection Applications</p> <p>QP1706, Capacity Change Requests</p> <p>QP1709, Motor Connection Assessment</p> <p>QP1710, Network Connections To Street Lighting</p> <p>QP1711, Notice To Telecommunication Providers</p> <p>QP1715, Reapportionment Of Capital Contributions</p> <p>QP1716, Line Charge Schedules</p> <p>QP1719, Removal Of Metering Equipment</p> <p>QP1720, Distributed Generation Less Than 10kw</p> <p>QP1721, Sub-Transmission Cable Installation</p> <p>Voltage Control</p> <p>QP1801, Subtransmission Voltage Control</p> <p>QP1802, Voltage Complaint Procedure</p> <p>QP1803, HV And LV Voltage Control</p> <p>QP1804, Subtransmission Voltage Parameters</p> <p>QP1901, System Planning Procedures</p> <p>QP1918, Half Hour Data Loading Procedure</p> <p>Network Records</p> <p>QP2101, Land Record Maintenance</p> <p>QP2102, Relay Settings</p> <p>QP2104, Processing Feeder Plans</p> <p>QP2106, Processing Completion Notice</p> <p>QP2107, Cable Location Records</p> <p>QP2109, Network Outage Reports</p> <p>QP2110, Network Manuals</p> <p>QP2115, Filling in Completion Packages</p> <p>QP2116, Ripple Plant Tuning</p> <p>QP2117, Application for Surge Arrestors</p> <p>QP2118, GIS Data Entry Requirements</p> <p>GIS Electrical Data Entry Manual</p> <p>QP2153 – QP2180 contain various requirements specific to each asset class.</p> <p>Maintenance Procedures</p> <p>QP1502, SCADA Database Maintenance</p> <p>QP1504, Overhead Lines Inspection</p> <p>QP1507, Gas Cable-Leak Location</p> <p>QP1508, Overhead to Underground Conversions</p> <p>QP1509, Request to Move Aurora Works</p> <p>QP1510, Transformer Load Guide</p> <p>QP1511, Tree Near Electricity Equipment</p> <p>QP1512, ONAN Transformer Temperature Monitoring Maintenance</p> <p>QP1513, Vegetation Management</p> <p>QP1514, Public and Contractor Safety Services</p> <p>Maintenance Standards</p> <p>MS01.00, Circuit Breakers</p> <p>MS02.00, On Load Tap Changes</p> <p>MS03.00, Protection Relays</p> <p>MS04.00, 33kV Air Break Switches</p> <p>MS06.00, SCADA Analogue Testing</p> <p>MS07.00, Intertrip Testing</p> <p>MS08.00, Ripple Control Equipment Zone</p>

Activity	Exiting Documents
	MS09.00, Lead Acid Batteries MS12, Distribution Transformer Assessment and Refurbishment Maintenance Plans PN1501, Zone Substation Maintenance PN1502, Substation Maintenance, PN1503, HV & LV Lines and Cables Maintenance PN1504, Distribution Substation Maintenance PN1505, System Control Maintenance Plan Service Work Guides
Resource Management	Contractor Management Policy QP1101, Tendering and Contract Administration QP1102, Approved Supplier Schedule for the Aurora Network
Control of Work	QN12, Inspection and Testing QP1103, PC1400 & PC 1405 Work Orders and Purchase Orders QP1201, Test Report Requirements QP1202, Earth Testing and Inspections QP1203, HV Cable Testing QP1204, LV Cable Testing QP1205, Zone Sub Earth Testing QP1206, Polarity Testing QP1207, Protection Relay Commissioning Tests QP1704, Network Connection Inspection QP1705, Authorised Network Inspector Approval QP1902, Project Quality Plans

Appendix E – Network Development project list

Year 2013/14

Project by Asset Type	Asset Type	Short Description	Sum of 2013/14
[-] Growth	[-] Subtransmission		340
	[-] 4149	Install 33kV circuit breaker at Omakau zone substation	10
	[-] 4150	Install 33kV circuit breaker at Dalefield zone substation	100
	[-] 4152	Install 33kV circuit breaker at Remarkables zone substation	100
	[-] 4153	Install 33kV breaker at Clyde-Earnsclough Substation	10
	[-] 4182	Upgrade Glenorchy supply to 33 kV	120
	[-] Zone substations		5,520
	[-] 2969	Land Acquisition for Riverbank Rd 66kV Switching station and designation	175
	[-] 3023	New zone substation in Maori Point Rd - Tarras irrigation scheme	1,365
	[-] 4135	Upgrade Maungawera Substation from 3 to 5 MVA	330
	[-] 4213	Land Acquisition for Maungawera Substation and designation	50
	[-] TBC	Fire , Security and Earthquake Upgrades	100
		Queensberry/Bengido upgrade	3,500
	[-] Distribution and LV lines		8,170
	[-] 2298	Establish new Wanaka HV feeder 2757 into Dungarvon St.	220
	[-] 3058	New Connections Dunedin	1,347
	[-] 3059	New Connections Central	5,391
	[-] 3165	New Wanaka Feeder 2751	600
	[-] 3896	New Feed to Cromwell CBD	
	[-] 4161	Upgrade of Maungawera 11kV feeder to Devon Dairy	42
	[-] 4207	Create intertie Between QT5232 and QT5242 to facilitate the off loading of QT5232	70
	[-] Distribution and LV cables		3,231
	[-] 3043	OH to UG Conversion Dunedin Area	1,363
	[-] 3044	OH to UG Conversion CODC Area	528
	[-] 3045	OH to UG Conversion QLDC Area	890
	[-] 4183	HV Distribution - Tarras Irrigation Scheme	450
	[-] 4206	Replace OH line in Dungarvon St Wanaka with 300mm cable.	
	[-] Distribution substations and transformers		792
	[-] 3061	Dunedin load growth projects yet to be identified	100
	[-] 3062	Central load growth projects yet to be identified	500
	[-] 3200	Extra cost of Dual ratio distribution transformers	80
	[-] 3788	Waterproof Centry Theatre UG Sub	50
	[-] 3789	Waterproof Dowling St No.1 UG sub	50
	[-] 4187	Install Micro Planet LV voltage regulator at distribution substation WS200	12
	[-] Distribution switchgear		150
	[-] 3741	ET2 - Recloser at urban boundary	
	[-] 3743	CE195 - Recloser on Springvale Road spur	50
	[-] 3744	AX168 - Recloser on Dunstan Rd spur	50
	[-] 3745	AB9 - Recloser at Tomahawk	50
	[-] Other network assets		50
	[-] 3807	Replace transformer Buchholtz relays at Central zone subs	20
	[-] TBC	Replace transformer Buchholtz relays at Dunedin zone subs	30
[-] Renewal	[-] Subtransmission		2,100
	[-] 3053	Replace Alexandra 33kV line breakers (3)	200
	[-] 4038	Replace Lower Shotover River 33 kV Crossing Old School Road with cable across bridge.	1,000
	[-] 4178	Replace Port Chalmers VWVE 33 kV circuit breakers with Seimens breakers	100
	[-] 4212	Port Chalmers to Peninsular Harbour Crossing Upgrade	800
	[-] Zone substations		
	[-] Distribution and LV lines		3,000
	[-] 3809	Arrange to have LV services removed from Mosgiel zone substation to local services Transformer	
	[-] 4204	Pole replacements 2012/13 Dunedin Area	1,000
	[-] 4205	Pole replacements 2012/13 Central Area	2,000
	[-] Distribution and LV cables		650
	[-] 2622	Dunedin UG link box upgrades, three per year.	150
	[-] 3272	Undergrounding of OH from Frankton Sub to Glenda drive for LTSA roading work.	500
	[-] Distribution substations and transformers		370
	[-] 3031	Annual Replacement of pole mounted substations	250
	[-] 3032	Ongoing replacement of distribution transformers	120
	[-] Distribution switchgear		446
	[-] 2145	Distribution CB replacement - Tennyson St rectifier	
	[-] 2146	Distribution CB replacement - Great King St rectifier	120
	[-] 3029	Ongoing replacement of Andelect Boxes in the Dunedin Area	36
	[-] 3211	Replace Pacific fuses in Central	60
	[-] 3772	Replace one KFE recloser in Central - unit to be identified	50
	[-] 4184	Replace the Otakou voltage regulator	100
	[-] TBC	Replacement of oil-filled switchgear	80
	[-] Other network assets		1,863
	[-] 2630	SCCP P4 - Upgrade Dunedin SCADA RTUs	385
	[-] 3354	Upgrade Cromwell transformer breathers with Messko units	26
	[-] 3355	Upgrade Clyde-Earnsclough transformer breathers with Messko units	26
	[-] 4214	Replacement of Dunedin street lighting ripple control relays.	80
		SCCP P1 (Part B) - Future SCADA master station operating system upgrade	100
		SCCP P2 - DUD, Central and DUD - Central Comms Upgrade	553
		SCCP P3 - Central Load Control System Upgrade	80
		SCCP P6 - Dunedin Subtransmission network protection system upgrade	380
		SCCP P7 - Aurora ICCP System	220
		Upgrade Coronet peak transformer breathers with Messko units	13
Grand Total			26,682

Years 2014/15 – 2017/18

Project by Asset Type	Short Description	2014/15	2015/16	2016/17	2017/18
Growth		19,154	16,448	14,563	12,538
Subtransmission		1,510	2,250		
3216	Install 66kV cables from Riverbank Rd substation to Wanaka Sub and to UC2 line.	250	2,250		
4149	Install 33kV circuit breaker at Omakau zone substation	90			
4153	Install 33kV breaker at Clyde-Farnsleugh Substation	90			
4182	Upgrade Glenorchy supply to 33 kV	1,080			
Zone substations		4,620	3,925	5,255	3,555
3019	Install 10 MVA transformers and new switchgear at Arrowtown Zone Sub.		40	1,980	1,980
3022	Construct Riverbank Rd 66kV switching station.	100	1,950	1,950	
3023	New zone substation in Maori Point Rd - Tarras irrigation scheme	2,835			
3024	Install two new 24 MVA transformers at Cromwell substation		250	1,125	1,125
3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.				250
4135	Upgrade Maungawera Substation from 3 to 5 MVA	1,485	1,485		
TBC	Fire , Security and Earthquake Upgrades	200	200	200	200
	Queensberry/Bengido upgrade				
Distribution and LV lines		6,106	5,502	5,502	5,502
3058	New Connections Dunedin	1,145	1,100	1,100	1,100
3059	New Connections Central	4,583	4,402	4,402	4,402
4207	Create intertie Between QT5232 and QT5242 to facilitate the off loading of QT5232				
Distribution and LV cables		5,422	3,351	2,526	2,301
3043	OH to UG Conversion Dunedin Area	1,175	1,127	1,127	1,127
3044	OH to UG Conversion CODC Area	455	437	437	437
3045	OH to UG Conversion QLDC Area	767	736	736	736
4183	HV Distribution - Tarras Irrigation Scheme	3,025	1,025		
4206	Replace OH line in Dungarvon St Wanaka with 300mm cable.		25	225	
Distribution substations and transformers		1,280	1,280	1,280	1,180
3061	Dunedin load growth projects yet to be identified	100	100	100	100
3062	Central load growth projects yet to be identified	1,000	1,000	1,000	1,000
3200	Extra cost of Dual ratio distribution transformers	80	80	80	80
3790	Waterproof Hanover St No.1 UG Sub	50			
3791	Waterproof Hope St UG Sub	50			
3793	Waterproof Moray Place No.1 UG Sub		50		
3794	Waterproof Moray Place No.3 UG Sub		50		
3795	Waterproof St Andrew UG Sub			50	
3796	Waterproof Stuart St-Pit St UG Sub			50	
Distribution switchgear		166	90		
3746	AX168 - Recloser on Letts Gully spur	50			
3747	Transfer of Part ET8 to new Mosgiel feeder	66			
3748	Ettrick - Recloser on Timaburn Road spur	50			
4137	Install voltage regulator in Jacks Point line, feeder FK7784		90		
Other network assets		50	50		
3807	Replace transformer Buchholtz relays at Central zone subs	20	20		
TBC	Replace transformer Buchholtz relays at Dunedin zone subs	30	30		
Renewal		7,811	14,365	7,564	9,094
Subtransmission		200	1,800	390	3,800
3171	Replace Kaikorai Valley 33kV cables				290
3470	Replace Willowbank 33kV gas cables			390	3,510
	Replace Neville St 33kV gas cables	200	1,800		
Zone substations		900	8,100	900	
2324	Rebuild Neville St zone substation on new site	600	5,400		
4179	Upgrade Outram Zone Substation	300	2,700	900	
Distribution and LV lines		3,000	2,000	2,000	2,000
3809	Arrange to have LV services removed from Mosgiel zone substation to local services Transformer				
4204	Pole replacements 2012/13 Dunedin Area	1,000	1,000	1,000	1,000
4205	Pole replacements 2012/13 Central Area	2,000	1,000	1,000	1,000
Distribution and LV cables		150	150	150	150
2622	Dunedin UG link box upgrades, three per year.	150	150	150	150
3272	Undergrounding of OH from Frankton Sub to Glenda drive for LTSA roading work.				
Distribution substations and transformers		370	370	370	370
3031	Annual Replacement of pole mounted substations	250	250	250	250
3032	Ongoing replacement of distribution transformers	120	120	120	120
Distribution switchgear		266	216	216	216
3029	Ongoing replacement of Andelect Boxes in the Dunedin Area	36	36	36	36
3211	Replace Pacific fuses in Central	60	60	60	60
3773	Replace one KFE recloser in Central - unit to be identified	50			
TBC	Replacement of oil-filled switchgear	120	120	120	120
Other network assets		2,925	1,729	3,538	2,558
2630	SCCP P4 - Upgrade Dunedin SCADA RTUs	385	364	238	378
4214	Replacement of Dunedin street lighting ripple control relays.	80	80	80	
TBC	SCCP P1 (Part A) - New System Control room	350	200	-	-
	SCCP P1 (Part B) - Future SCADA master station operating system upgrade	100	100	2,700	2,000
	SCCP P2 - DUD, Central and DUD - Central Comms Upgrade	830	170	170	-
	SCCP P3 - Central Load Control System Upgrade	-	-	-	-
	SCCP P5 - Upgrade Central SCADA RTU's	200	495	350	-
	SCCP P6 - Dunedin Subtransmission network protection system upgrade	860	320	-	180
	SCCP P7 - Aurora ICCP System	120	-	-	-
Grand Total		26,965	30,813	22,127	21,632

Year 2018/19 – 2022/23

Project by Asset Type	Short Description	2018/19	2019/20	2020/21	2021/22	2022/23
Growth		14,006	14,756	20,431	12,203	12,230
Subtransmission			200	1,800		
3021	Install 3rd 33/66kV auto transformer at Cromwell GXP and create 66kV bus		200	1,800		
Zone substations		3,350	3,875	7,925	1,550	1,550
2611	New Jacks Point zone substation			300	1,350	1,350
3038	Upgrade Andersons Bay substation. New Xfms and switchgear.	450	1,350	2,700		
3414	Upgrade Smith St Substation - new 24MVA transformers and HV switchgear	450	2,025	2,025		
3437	Install 24 MVA 66/11kV transformer and 11kV switchgear at Riverbank Rd substation.	2,250				
3438	New 66kV Switching Station at Queensberry		300	2,700		
TBC	Fire , Security and Earthquake Upgrades	200	200	200	200	200
	Queensberry/Bengido upgrade					
Distribution and LV lines		8,200	8,200	8,200	8,200	8,200
2298	Establish new Wanaka HV feeder 2757 into Dungarvon St.					
3058	New Connections Dunedin	1,200	1,200	1,200	1,200	1,200
3059	New Connections Central	7,000	7,000	7,000	7,000	7,000
Distribution and LV cables		1,276	1,301	1,326	1,353	1,380
3043	OH to UG Conversion Dunedin Area	609	621	633	646	659
3044	OH to UG Conversion CODC Area	252	257	262	267	272
3045	OH to UG Conversion QLDC Area	415	423	431	440	449
Distribution substations and transformers		1,180	1,180	1,180	1,100	1,100
3061	Dunedin load growth projects yet to be identified	100	100	100	100	100
3062	Central load growth projects yet to be identified	1,000	1,000	1,000	1,000	1,000
3200	Extra cost of Dual ratio distribution transformers	80	80	80		
Distribution switchgear						
Other network assets						
Renewal		6,151	6,372	6,456	2,556	2,556
Subtransmission		2,960	3,570	3,780		
3171	Replace Kaikorai Valley 33kV cables	2,610				
3469	Replace Ward Street 33Kv gas cables		420	3,780		
3471	Replace Smith St 33kV gas cables	350	3,150			
Zone substations						
Distribution and LV lines		2,000	2,000	2,000	2,000	2,000
3809	Arrange to have LV services removed from Mosgiel zone substation to local services Transformer					
4204	Pole replacements 2012/13 Dunedin Area	1,000	1,000	1,000	1,000	1,000
4205	Pole replacements 2012/13 Central Area	1,000	1,000	1,000	1,000	1,000
Distribution and LV cables		150	150	150	150	150
2622	Dunedin UG link box upgrades, three per year.	150	150	150	150	150
3272	Undergrounding of OH from Frankton Sub to Glenda drive for LTSA roading work.					
Distribution substations and transformers		370	370	370	370	370
3031	Annual Replacement of pole mounted substations	250	250	250	250	250
3032	Ongoing replacement of distribution transformers	120	120	120	120	120
Distribution switchgear		216	156	156	36	36
3029	Ongoing replacement of Andelect Boxes in the Dunedin Area	36	36	36	36	36
3211	Replace Pacific fuses in Central	60				
TBC	Replacement of oil-filled switchgear	120	120	120		
Other network assets		455	126	-	-	-
2630	SCCP P4 - Upgrade Dunedin SCADA RTUs	105	126	-	-	-
	SCCP P1 (Part B) - Future SCADA master station operating system upgrade	350	-	-	-	-
Grand Total		20,157	21,128	26,887	14,759	14,786

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152	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of assets, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2		Discussions with Asset Manager, Asset Systems Manager, Infrastructure Performance Manager. There are products of partially understood and well understood assets, risks etc, across various parts of the asset chain and lifecycle spans, but consistently across the business lifecycle improvement. An AM Improvement Program exists and the importance of reviewing performance and feeding back any lessons learnt is recognised. A risk team is responsible for making sense of risk, critically, location, condition etc and drawing a prioritised work program. Also see internal stores.	Which asset AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, reviewing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to document continual improvement as optimisation of cost risk and performance/condition of assets versus the life cycle. This question captures an organisation's capabilities in the area-making for continual improvement mechanised rather than reactive and ad-hoc (which are separately ranked).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Manager is responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Change in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and networks.
155	Continual Improvement	How does the organisation track and capture knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3		Discussions with Asset Manager, Asset Systems Manager, Infrastructure Performance Manager, Asset Specialist. Staff are part of industry groups, and attend training courses such as R4M2, road builder etc. Extensive networking of practitioners and collaboration are used. Information sources include IEA initiatives, interaction with other ESO's, with suppliers, attending conferences etc and training opportunities are identified. Potentially new products are evaluated for relevance to identify lower cost options. Some smart use, pending for the National Options is infrastructure Asset Management. However, there are gaps around specific asset classes and that the need for technical specialists for aging assets is not well understood.	One important aspect of continual improvement is when an organisation looks beyond its existing knowledge and knowledge base to look at other 'best things' out in the market. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg. by the R4M 2 & 4 it mentioned) 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 top risk opportunities to improve, enhance their fitability to its own organisation and implements them as appropriate. This question captures 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 mature items that require monitoring for 'change'. People that implement change 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 evolution of new tools, and techniques linked to asset management strategy and objectives.