



AURORA ENERGY LTD

Asset Management Plan Number 16

April 2009 – March 2019

Prepared for Aurora Energy Ltd
by *DELTA* Utility Services Ltd



ISO 9001

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TABLE OF CONTENTS

1	Summary	2
1.1	Purpose	2
1.2	Background and Objectives	2
1.3	Assets Covered.....	2
1.4	Service Levels.....	3
1.5	Network Development Plans	3
1.6	Lifecycle Asset Management Planning.....	4
1.7	Risk Management	4
1.8	Evaluation of Performance	4
1.9	Stakeholder Consultation	5
2	Background and Objectives.....	6
2.1	Purpose	6
2.2	Interaction between Plan Objectives and Other Corporate Goals, Business Processes and Plans	6
2.3	Period to Which Plan Relates.....	8
2.4	Stakeholder Interests	8
2.5	Accountabilities and Responsibilities.....	10
2.6	Details of Asset Management Systems and Processes.....	11
3	Assets Covered	13
3.1	High Level Description	13
3.2	Network Configuration.....	15
3.3	Subtransmission (66kV and 33kV)	16
3.4	HV Distribution (11kV and 6.6kV).....	21
3.5	Distribution Substations (11/0.4kV and 6.6/0.4kV)	23
3.6	LV Distribution (0.4kV)	24
3.7	Secondary Assets	24
3.8	Asset Details by Category	26
3.9	Justification for Assets	37
4	Service Levels	40
4.1	Customer Oriented Performance Levels	40
4.2	Network Reliability	42
4.3	Primary Customer Service Level Targets	43
4.4	Secondary Customer Service Level Targets	45

4.5	Tertiary Customer Service Levels	48
4.6	Regulatory Service Levels	49
4.7	Service Levels for Other Stakeholders	50
4.8	Justifying Service Levels	51
5	Network Development	53
5.1	Introduction	53
5.2	Distributed Generation Policy	54
5.3	Non-Network Solutions	54
5.4	Planning Criteria	55
5.5	Planning Process	55
5.6	Demand Forecasting Methodology.....	56
5.7	Project Prioritisation Methodology	56
5.8	Equipment Ratings.....	57
5.9	Grid Exit Points	58
5.10	Subtransmission	61
5.11	Zone Substations	62
5.12	HV Feeders.....	66
5.13	Distribution Substations	66
5.14	Reliability and Risk Mitigation Projects	67
5.15	Overhead to Underground Conversion Projects	68
5.16	New Customer Connections.....	68
6	Lifecycle Asset Management Planning for Maintenance and Renewal	70
6.1	Maintenance Planning Criteria and Assumptions	70
6.2	Routine and Preventative Inspection and Maintenance.....	71
6.3	Asset Renewal and Refurbishment Policies	75
6.4	Maintenance and Refurbishment Programmes	76
6.5	Capital Replacement Projects	78
7	Risk Policies, Assessment, and Mitigation	82
7.1	Methods, Details and Conclusions of Risk Analysis	82
7.2	Details of Emergency Response and Contingency Plans	86
8	Performance Measurement, Evaluation and Improvement	88
8.1	Review of Network Service Level Performance.....	88
8.2	Review of Financial Performance.....	89
8.3	Gap Analysis and Identification of Improvement Initiatives	91

F O R E W O R D

This is the sixteenth network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd, and covers the 10 year period from 1 April 2009.

It documents existing and projected network asset conditions, and the likely or intended asset management strategies, policies, plans, and thinking, based on the present understanding of customer and regulatory requirements, and regulatory demands. It is not an approved programme for specific work; rather, the programmes and projects are indicative. In some cases plans will be subject to user discussion and/or funding, while in all cases they are subject to financial approvals.

D I S C L A I M E R

As this document is indicative, Aurora Energy Ltd will not accept responsibility for decisions, by others, which are based upon information contained herein. Any person proposing to use information contained in this document for decision making purposes should consult with Aurora Energy Ltd before doing so.

1 Summary

1.1 Purpose

The purpose of this summary is to provide brief overview information that Aurora Energy Ltd (Aurora) considers significant.

1.2 Background and Objectives

This Asset Management Plan describes the asset management objectives, strategies, policies, plans and systems adopted by Aurora for its electricity distribution networks. It has been prepared in this format to meet the Electricity Distribution (Information Disclosure) Requirements 2008.

1.3 Assets Covered

The network assets consist of two geographically separate networks. The Dunedin network supplies 52,990 consumers in, and adjacent to, the urban area of Dunedin. The network in Central Otago, which stretches from Raes Junction to Lakes Wakatipu and Wanaka and north to St Bathans and Makarora, supplies 27,560 consumers.

The network assets comprise the types and quantities summarised in Table 1.1, located generally as shown in Figure 3.1. Their general condition is detailed in Section 3. The asset value and age data originates from the 2008 ODV data.

Asset Category	Quantity	RC	% by \$
Subtransmission	594 km	\$41,736,435	9%
Zone substations	36	\$96,638,950	21%
HV cables	782 km	\$72,476,897	16%
HV lines	2,353 km	\$61,315,237	13%
Distribution transformers	6,435	\$53,075,700	11%
Distribution switchgear		\$31,565,893	7%
Distribution substations	6,331	\$12,078,000	3%
LV distribution	1,726 km	\$76,403,484	16%
Service connections (80,500 customer connections, the remainder are streetlights)	94,662	\$13,367,305	3%
Street lighting distribution	224 km	\$6,237,230	1%
System control		\$1,667,200	< 1%
Sundry		\$562,593	< 1%
Total		\$467,124,924	100%

Table 1.1 – Types and Quantities of Assets

Approximately 1.82% by Depreciated Replacement Cost (DRC) of existing assets has been “optimised” out of Aurora’s revenue base. This represents the degree of asset stranding due to changes in either consumer requirements or technology since these assets were installed.

1.4 Service Levels

Service level objectives are summarised in Table 1.2. Details appear in Section 4.

Function	Objective
General Network Performance	Average of no more than 88 minutes without supply per customer per year. (SAIDI)
Response Time - Dunedin Network Area Restore supply following general network failure.	Within 4 hours of notification.
Response Time - Central Network Area* Restore supply following general network failure.	Within 4 hours of notification in urban areas, and within 6 hours of notification in rural areas.

Table 1.2 – Service Level Objectives

Aurora’s primary service level focus is the System Average Interruption Duration Index (SAIDI); other indicators are considered to be secondary. However, in the consumer survey described in Section 4.1.1, consumers wish to have fewer interruptions, therefore Aurora believes that making small improvements to SAIDI minutes is appropriate with specific emphasis on reducing the number of interruptions, as measured by the System Average Interruption Frequency Index (SAIFI).

1.5 Network Development Plans

New capital works are driven by demand growth in existing connections, new connections, replacement of equipment where it is economic to do so, and the community desire to underground overhead distribution for aesthetic reasons.

Probabilistic analysis is used to determine when equipment replacement and new capital works are economic. Planned capital expenditure, as detailed in Table 5.1, is summarised in Table 1.3 below:

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	81/19
Total	15,010	14,960	19,040	19,470	19,930	19,700	20,740	20,280	20,330	20,450

Table 1.3 - Capital Expenditure (\$000)

* For Retailers using the standard Use-of-System Agreement dated July 2005.

1.6 Lifecycle Asset Management Planning

Aurora's maintenance strategy is based on continual monitoring of asset condition and performance.

Asset management policy is to evaluate and balance the cost of maintenance against the prospective cost of failure, refurbishment/renewal costs and the cost of non-supply. Asset renewal is determined when the cost of maintenance is greater than the cost of replacement.

As a result of continual refurbishment work, the network is in reasonably good condition. Improved knowledge and analysis of maintenance trends continues to result in inspection and test intervals being extended in some instances, and reduced in others. Maintenance requirements are continually monitored, and are subject to change as optimum levels evolve. The maintenance expenditure from Table 6.2 is summarised in Table 1.4. below:

Financial Year	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Total Maintenance Expenditure	7,648	7,858	8,075	8,297	8,525	8,759	9,000	9,248	9,502	9,763

Table 1.4 – Total Maintenance Expenditure (\$000)

1.7 Risk Management

Risk assessment and risk management strategies focus on four principal areas:

- (1) health and safety;
- (2) responsibilities dictated by the Resource Management Act;
- (3) network capacity (new capital investment for load growth) ;
- (4) network reliability (maintenance and/or restoration of supply).

Procedures contained in *DELTA's* Asset Management Quality System detail operational and planning policies and guidelines for dealing with each of these risk management areas.

The risk of insufficient competent human resource to complete capital works in a timely manner is highlighted as a potential industry wide concern.

1.8 Evaluation of Performance

The diagram below compares the performance achieved by Aurora's network with that achieved by other large Electricity Lines Businesses (ELBs) in the year to 31 March 2007.

When judged on the combination of low price (average distribution charge/kWh delivered) and high quality (low SAIDI)¹, the Aurora network, shown as the shaded square in Figure 1.1 below, was in the 'best-performer quartile' of New Zealand's 28 large ELBs.

This analysis provides a great degree of confidence that Aurora's performance is satisfactory.

¹ SAIDI = System Average Interruption Duration Index (minutes).

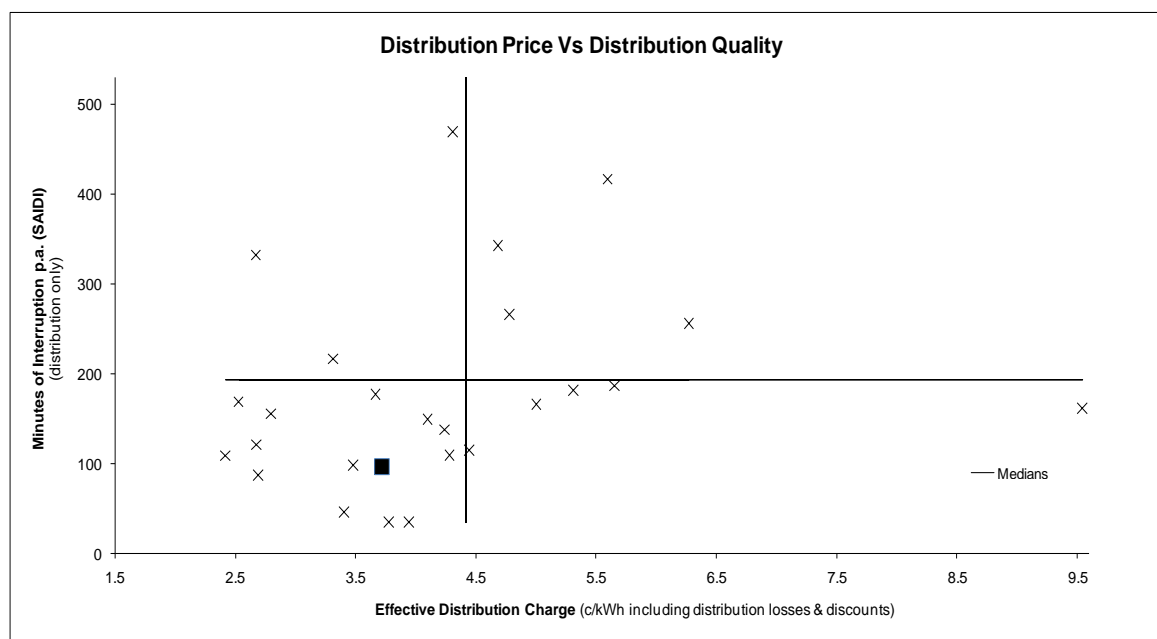


Figure 1.1 – Price-Quality Matrix

1.9 Stakeholder Consultation

Aurora's process for continual improvement will remain focussed on optimising the trade-off between price and quality. To this end, Aurora invites questions, comments, and suggestions for improvement of this Asset Management Plan at any time.

These can be lodged through www.electricity.co.nz/AMP.htm or by writing to:

Aurora Energy Ltd
P O Box 1404
DUNEDIN

This plan concentrates on asset management principles and overall indicators of asset condition and performance. Existing or potential users of network assets may request more details regarding the specific assets that affect them.

For some years, Aurora has actively sought comment on its Asset Management Plan, including through newspaper advertisements and direct approaches. There was one instance of feedback regarding demand growth on the 2006 Asset Management Plan and this was taken into account in the preparation of the 2007 Asset Management Plan. No other comment had been received in response, other than from the Commerce Commission and its agents. Separately, Aurora has also sought feedback from consumers on the level of reliability received and the price paid to assist with assessing whether consumers receive value for service.

In order to improve on this generally low level of public feedback, Aurora uses external consultants to assist in the ongoing development of the Asset Management Plan, policies and processes.

2 Background and Objectives

2.1 Purpose

The purpose of this document is to summarise Aurora's asset management methodology and practices to provide a systematic representation, ownership, governance and management framework that ensures that Aurora:

- sets service levels for Aurora's electricity networks that will meet consumer, community and regulatory requirements;
- understands what network capacity, reliability and security of supply is required, both now and in the future, and what issues drive these requirements;
- has robust and transparent processes in place for managing all phases of the network life cycle;
- 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 an ever-increasing knowledge of Aurora's asset locations, ages, conditions, and likely future behaviour.
- makes all decisions within systematic frameworks and guidelines.

Preparation of the Asset Management Plan in this format also assists in meeting the requirements of Section 7 of the Electricity Distribution (Information Disclosure) Requirements 2008.

2.2 Interaction between Plan Objectives and Other Corporate Goals, Business Processes and Plans

Aurora's corporate strategic asset management drivers reflect the company's corporate mission statement:

“TO BE THE BEST PERFORMING INFRASTRUCTURAL BUSINESS IN NEW ZEALAND”

Aurora has four levels of corporate planning: a Strategic Plan, this 10-year Asset Management Plan, a Six-Year Development Plan, and an annual budget. Interaction between business processes and plans are detailed in Figure 2.1 overleaf.

Aurora's Strategic Plan sets out the vision of the Company and the key objectives that must be achieved if that vision is to be realised. The plan takes into account aspects such as regulatory, customer, staff and shareholder constraints and expectations, and defines and shapes the AMP.

Aurora maintains a Six-Year Development Plan, which details potential developments to provide for anticipated load growth, improved security and reliability, and appropriate asset renewal. It is confidential to Aurora. This is approved by the Board prior to setting annual budgets. It contains more detail regarding capital works than the AMP, and is used as the basis of the proposed capital works programme contained herein.

This Asset Management Plan covers the period from 1 April 2009 to 31 March 2019, and represents an evolution of the annual Asset Management Plans published for the Dunedin network since 1993.

The Board approved this (2009 – 2019) Asset Management Plan on 1 April 2009.

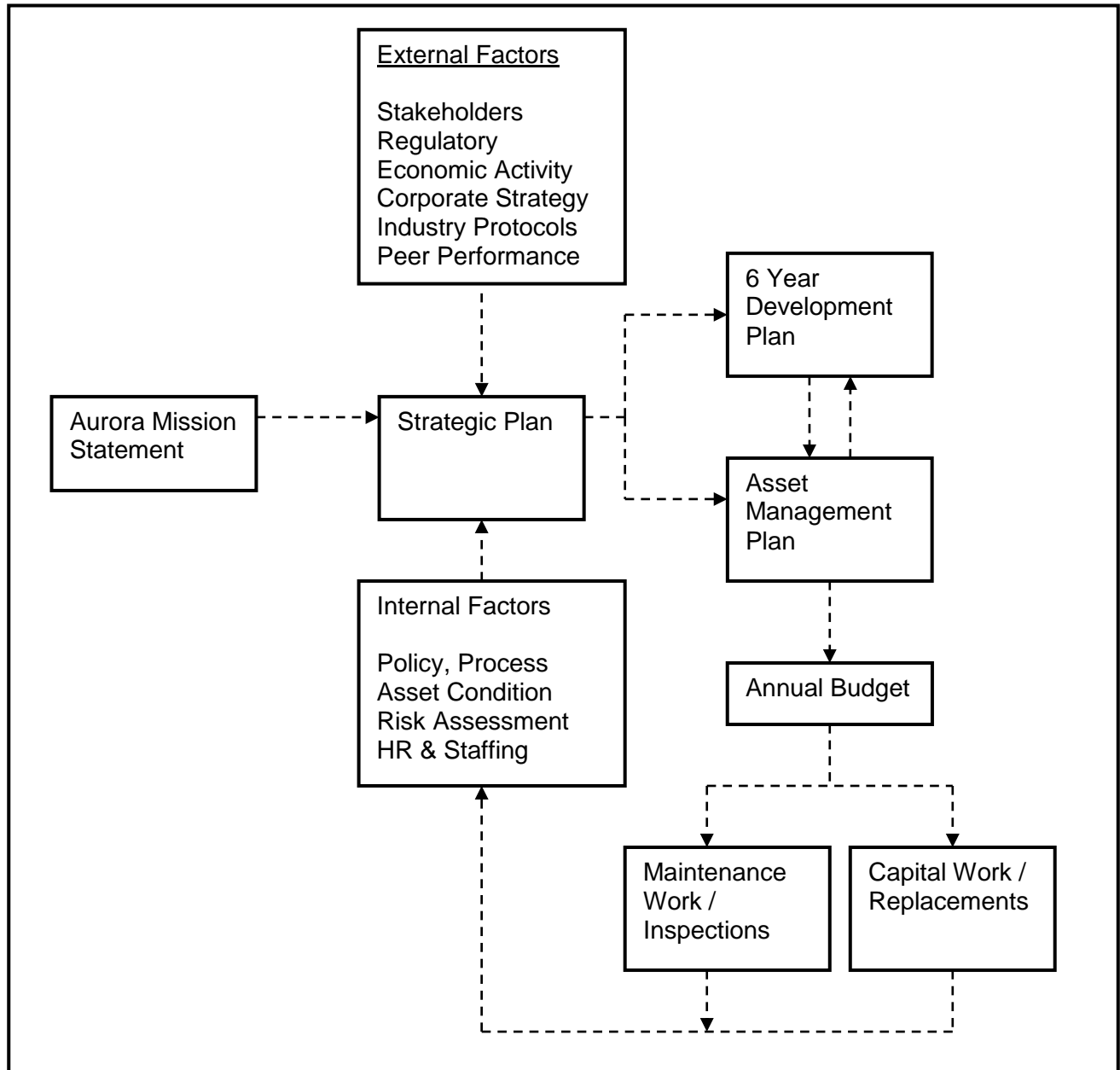


Figure 2.1 - Interaction Between Other Business Processes and Plans

2.3 Period to Which Plan Relates

This plan relates to the 2009 - 2019 period.

The plan is subject to change without notice in the event of significant unanticipated equipment failures, storm or disaster, or material changes in local loadings.

There is an obvious degree of uncertainty in any predictions of the future and, accordingly, the AMP is uncertain.

Following the announcement of several unforeseen industrial closures in Dunedin, and a falling off of customer initiated works coupled with a slump in international economic activity, Aurora has attached the following certainties to the timeframes of the AMP.

Timeframe	Residential and Commercial	Large Commercial and Industrial	Intending Generators
Year 1	Certain	Reasonably certain	Reasonably certain
Years 2 and 3	Reasonably certain	Some certainty	Some certainty
Years 4 to 10	Little if any certainty	Little if any certainty	Little if any certainty

Table 2.1 – Loading Certainties

2.4 Stakeholder Interests

2.4.1 Stakeholders

Stakeholders are those parties with a direct interest in Aurora's network asset management policies and practices. The exact nature of stakeholder interests are identified by customer surveys, open requests for feedback, safety reviews, industry forums and other means. The principal stakeholders and the nature of their interests are as summarised follows:

Stakeholder	Interest
Contractors who provide services to Aurora	Contractual relationship Safe working environment Continuity of work
Electrical Contractors who work for consumers and developers	New-connection policies Maintenance and upgrade policies
Electricity Consumers	Line charges Network reliability/service quality Optimisation of electrical losses New-connection policies
Electricity Retailers, and embedded generators	Line charges Network reliability/service quality Contractual arrangements Optimisation of electrical losses
Employees	Health and safety Creative work environment Career opportunities
Government	Economic efficiency Compliance with statutory requirements

Stakeholder	Interest
Landowners with network facilities on their land	Safety Easement conditions Access for maintenance/repair Compensation for significant interference
Property developers	New-connection policies Timely network expansion
Shareholder	Adequate, stable, and secure return on investment Good corporate citizenship
Territorial authority	Minimising of environmental impacts (RMA) Local economic development Control of assets in road reserve Conversion of overhead to under-ground
NZ Transport Agency	Control of assets in road reserve
Transpower	Reliability of supply Investment for growth

Table 2.2 – Stakeholder Interests

This list is illustrative of the issues Aurora takes into account, but is not exhaustive.

Stakeholder interests are accommodated by considering the following aspects of asset management:

- Safety: Safety is given the top priority – Aurora will not compromise the safety of contractors' staff or the public.
- Reliability/cost trade off: the network reliability targets are set as a reflection of Aurora's understanding of customer needs.
- Economic growth: Aurora will facilitate economic growth in the areas it serves by providing an electrical distribution network, on an economic basis, to meet consumers' needs.
- Environmental responsibility: where practicable, Aurora will enhance the environment it serves. Examples include:
 - undertaking under-grounding projects in partnership with local authorities;
 - paying particular attention to new zone substation designs;
 - liaising with potentially affected parties associated with new works with the aim of providing economic but visually inoffensive solutions.
- Legislative compliance: Aurora will comply with New Zealand legislation.

In consideration and management of stakeholder conflict, Aurora will apply the criteria explained above, in order of priority, with safety being the primary concern. The Aurora Board will decide upon any issue of conflict between stakeholder interests.

2.4.2 Continuance of Supply

Under the provisions of Section 62 (Continuance of Supply) of the Electricity Act 1992, Aurora's obligation to provide lines services (subject to Section 62.3) to all points of supply expires after 31 March 2013.

While Aurora recognises that some points of connection are, or may become, uneconomic, it intends to continue maintaining supply to them beyond 2013 via cross-subsidisation, conditional on an acceptable overall return on investment in the network and while 'cherry-picking' by other network owners is not evident.

However, line businesses will be required to continue to supply electricity beyond 31 March 2013 if the Electricity (Continuance of Supply) Amendment Bill 296-1 (2008), Government Bill is adopted.

2.5 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.

Figure 2.2 details the accountabilities and responsibilities for asset management within the Aurora / *DELTA* contract.

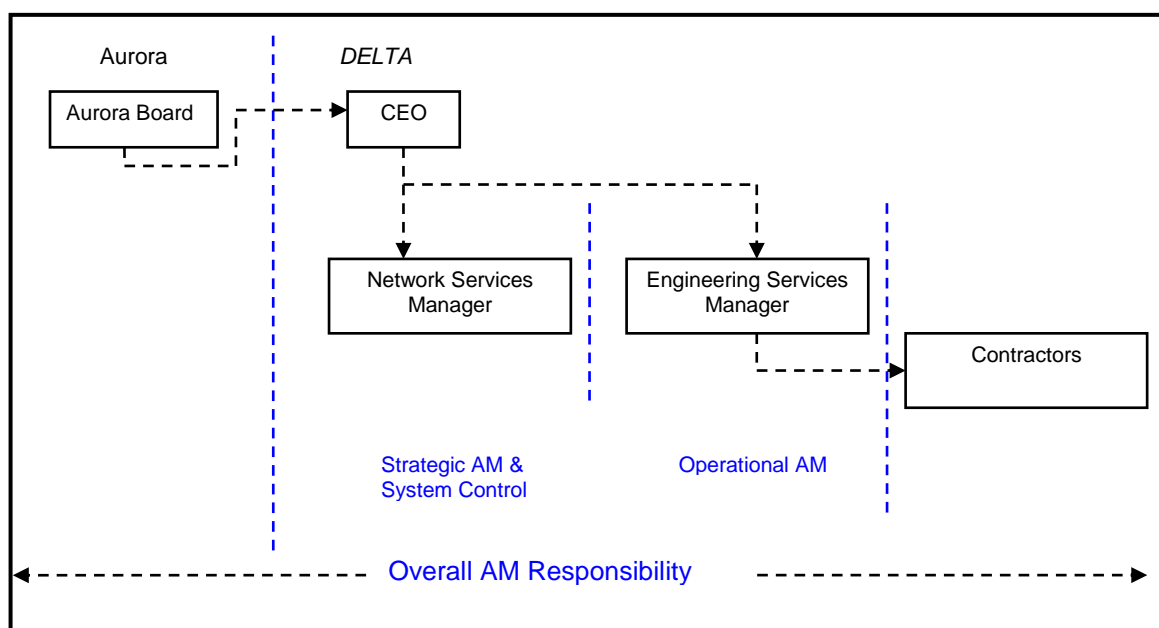


Figure 2.2 - Asset Management Accountabilities and Responsibilities

Under the asset management contract with *DELTA*, the responsibility for the management of the network is primarily through *DELTA*'s Chief Executive and the day-to-day operational management is delegated to *DELTA*'s Engineering Services and Network Services Managers, who together form the network management group within *DELTA*.

The delegated financial levels are given in Table 2.2 below:

Staff Level	Budgeted Expenses	Budgeted Capital Expenditure
Aurora Company Secretary	\$5,000,000	\$250,000
<i>DELTA</i> Chief Executive	\$5,000,000	\$250,000
<i>DELTA</i> Network Services Manager	\$3,000,000	
<i>DELTA</i> Engineering Services Manager	\$1,000,000	\$100,000

Table 2.3 – Delegated Financial Authority Levels

The Engineering Services Manager's responsibilities include asset planning, asset management including contractor and records management, and the capital expenditure programme.

The Network Services Manager's responsibilities include managing Aurora's contracts with energy retailers and directly connected consumers, Transpower, embedded generators, embedded network owners, use-of-system pricing policies, regulatory matters, the billing of line charges and outage management.

DELTA has made use of external contractors and consultants for works associated with the annual operational, maintenance, capital replacement and network development programmes.

The Aurora Board receives both regular and special reports from *DELTA*, and meets monthly to review a range of operational indicators and to consider strategic issues. Regular reports include financial reporting, capital expenditure, energy and system demands, outage summaries, and specific reports of all outages over 0.5 SAIDI minutes.

The capital programme is approved by the Board during the annual budgeting process.

DELTA advises that its Information Systems Strategic Plan was reviewed in 2007 and that it has a broad range of strategic objectives in hand to ensure its continued excellence in asset management, vis-à-vis its competitors.

While the information systems hardware and software belong to *DELTA*, the information they contain belongs to Aurora and must be provided to any new asset manager retained by Aurora when the current contract ends.

2.6 Details of Asset Management Systems and Processes

The asset management information systems are built around an ESRI geographic information system, which interfaces with the corporate Oracle database and the following suite of asset management tools:

- Application-for-supply Management System: the process of negotiating and constructing new connections is electronically managed from application to liveness.
- Maintenance Management System: 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.

- Work Order Management System: the issue of work to, and inspection of work by, contractors is managed electronically within the SAP accounting software.
- Production of ODV summaries and analysis is integrated with the core records of plant items.
- Outage Management System: planning and notification of outages and production of interruption statistics.
- Load Data: load data, (demand and total energy), is collected and analysed for growth trend information.

While the core of these systems is generally a commercial product, enhancement and development since separation of line and energy activities in 1993 has given *DELTA* a significant strategic advantage over its competitors in the management of such utility assets.

In June 1995, Aurora (then named Dunedin Electricity Limited) achieved ISO certification for its Asset Management Quality System. Successive audits by the Telarc registration authority have seen that ISO certification maintained by *DELTA*. The data stored in these systems is regularly analysed to determine economic ways of maintaining system reliability (SAIDI) at the least cost to the consumer.

Section 3 details deficiencies in asset information (mainly dates) for each of the asset categories described. These deficiencies are being incrementally addressed as this becomes the economic course of action. Date data is not considered to be as important as condition data. Missing date data relates to old equipment with corresponding low residual value. As such, the benefits to be gained by improving date data for its own sake are minimal and are not actively pursued unless there is a perceived economic case to do so. Efforts to improve the quality of condition data, particularly for poles, will take a higher priority than the improvement of date data.

3 Assets Covered

3.1 High Level Description

3.1.1 Areas Covered

The network assets consist of two geographically separate networks in Dunedin and Central Otago as shown in Figure 3.1 below.

- The geographically smaller network is the electricity network that supplies 52,823 consumers in the urban areas of Dunedin, Mosgiel, and the inner reaches of the Taieri Plains. 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 network in Central Otago, which 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, supplies 26,915 consumers. 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.

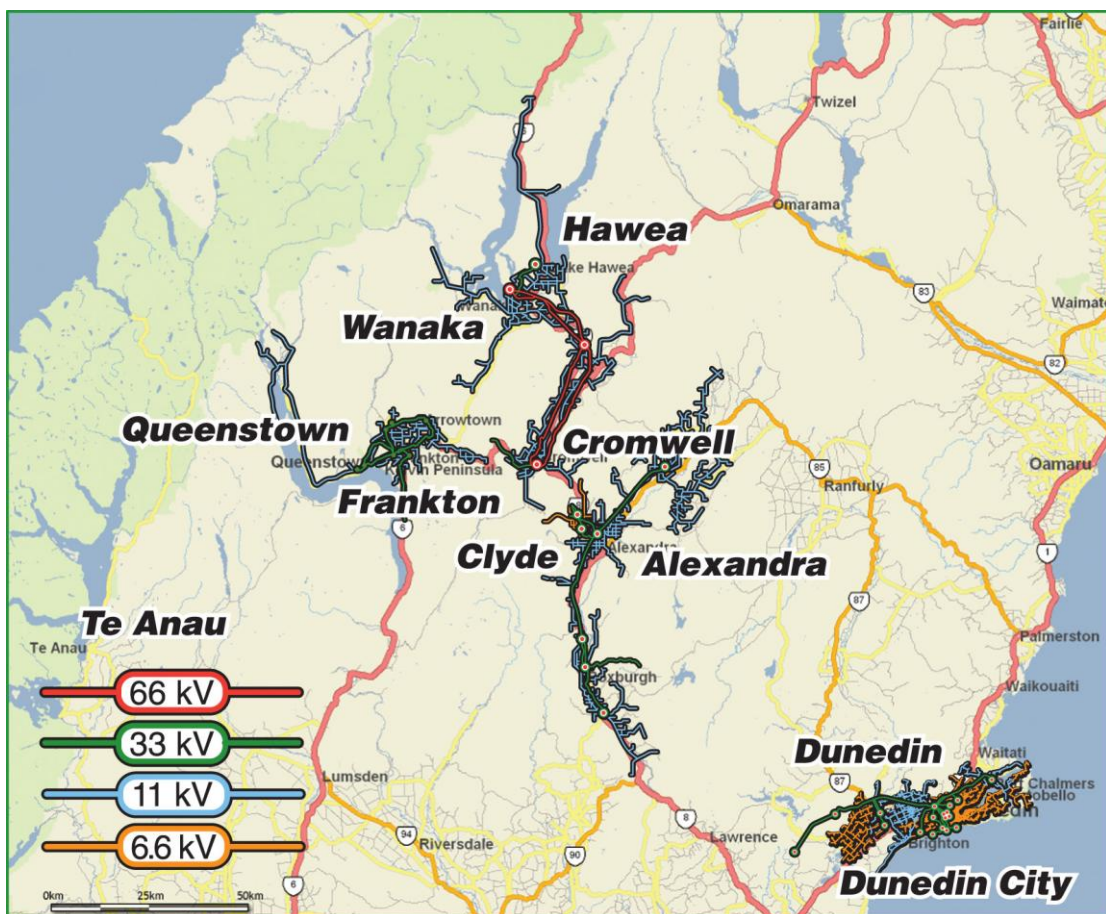


Figure 3.1 – Aurora Network

3.1.2 Large Consumers

The largest consumer that has a significant impact on network operations is the University of Otago with a peak load of 5MW.

3.1.3 Load Characteristics

The load in all areas is dominated by residential and commercial load; ie the industrial load with its characteristic flicker and poor power factor, while potentially significant at HV feeder level is not significant at zone sub or GXP level. All GXP areas have their peak demand in winter. The daily peak loads for 2007, which were larger than the 2008 peak loads, for each GXP are shown in Figure 3.2.

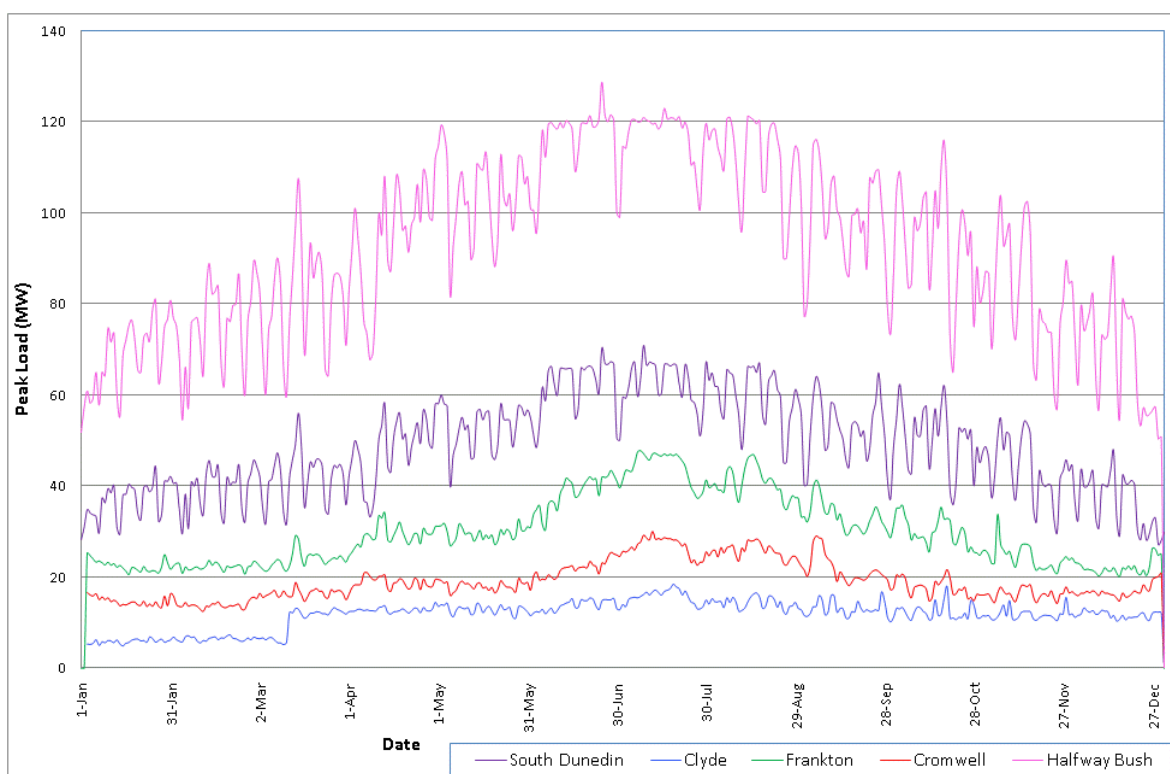


Figure 3.2 - Graph of Grid Exit Point Daily Load Peaks (2007)

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 where the Queensberry zone substation has a summer peak; however, the Cromwell GXP peak is not expected to shift from winter within the planning period.

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), 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.

3.1.4 2008 Load Data

The key load and embedded generation statistics for the 2008 calendar year are presented in Table 3.1.

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2008 peak MW including embedded generation	16.4	28.0	48.0	124.0	70.5	286.9
2008 energy transported GWh	82.8	129.0	214.3	595.8	316.2	1338.1
Total number of ICPs	6,570	9,850	11,090	36,370	16,620	80,500
Off take n-1 capacity (24 hour winter post contingency) MVA	27	35	88	112	81	

Table 3.1 - GXP Load and Capacity Summary

3.2 Network Configuration

The Aurora network is supplied from five Transpower GXPs as detailed above. The significant distributed generation that exports to the Aurora networks, at each GXP is detailed in Table 3.2.

GXP	Embedded Generation	Connection Voltage kV	Installed Generation Capacity MVA
Halfway Bush	Waipori	33	44
	Ravensdown Fertiliser	6.6	2.8
South Dunedin	None		
Frankton	Glenorchy	11	0.5
	Wye Creek	33	1.3
Cromwell	Roaring Meg	33	4.3
Clyde	Fraser	33	2.5
	Teviot	33	14.8
Total			70.2

Table 3.2 - Schedule of Embedded Generation

Various small scale generation projects are being connected by others. These have little effect on the network.

3.3 Subtransmission (66kV and 33kV)

3.3.1 Dunedin Area

The Dunedin network area is supplied from the Halfway Bush and South Dunedin GXP's. There are 19 33kV breakers 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 33/6.6kV transformers. The North East Valley zone substation is teed off the Port Chalmers zone substation 33kV circuits. The Taieri Plain area, including Mosgiel, is served by four zone substations which are supplied from the three parallel 33kV lines between the Halfway Bush GXP and TrustPower's Waipori power scheme. An overview of the network is shown in Figure 3.3 and zone substation details are in Table 3.3.

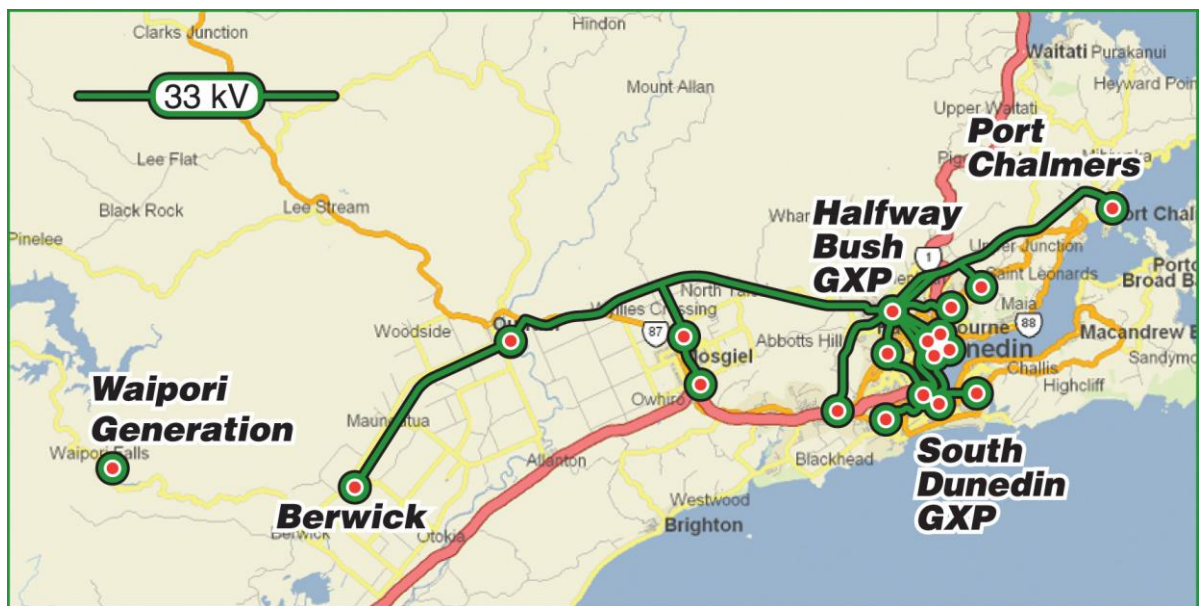


Figure 3.3 - Dunedin Subtransmission Network

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

Table 3.3 - Zone Substations in the Dunedin Area

3.3.2 Frankton Area

The Frankton area is supplied via seven 33kV circuit breakers 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 ring supplies the Remarkables ski field and the Wye Creek generating station. An overview of the network is shown in Figure 3.4 and zone substation details are in Table 3.4.

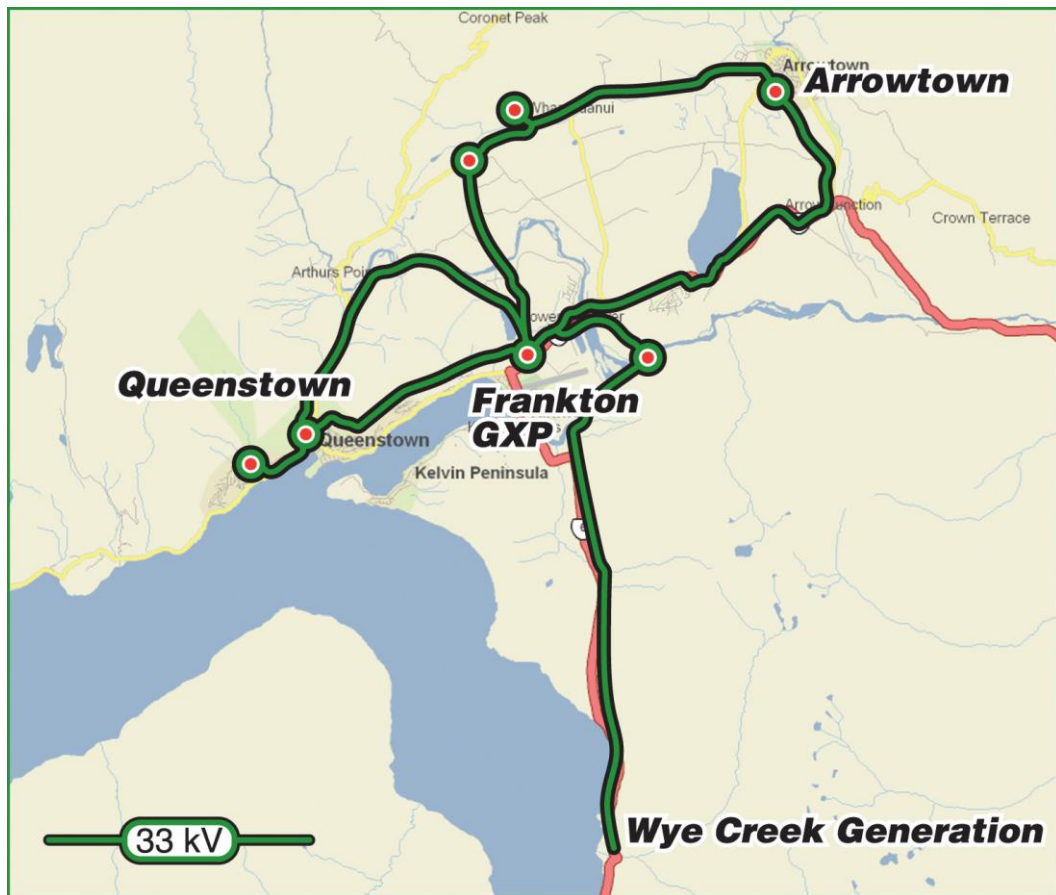


Figure 3.4 - Frankton Subtransmission Network

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

Table 3.4 - Zone Substations in the Frankton Area

3.3.3 Cromwell Area

The Cromwell area is supplied via four 33kV circuit breakers at the Cromwell GXP. Two of the circuits supply two Aurora-owned, 33/66kV, 30MVA, auto transformers, adjacent to the GXP, which supply the Wanaka area via two parallel 66kV 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, 66/33/11kV units, with the 33kV windings supplying the Maungawera zone substation. An overview of the network is shown in Figure 3.5 and zone substation details are in Table 3.5.

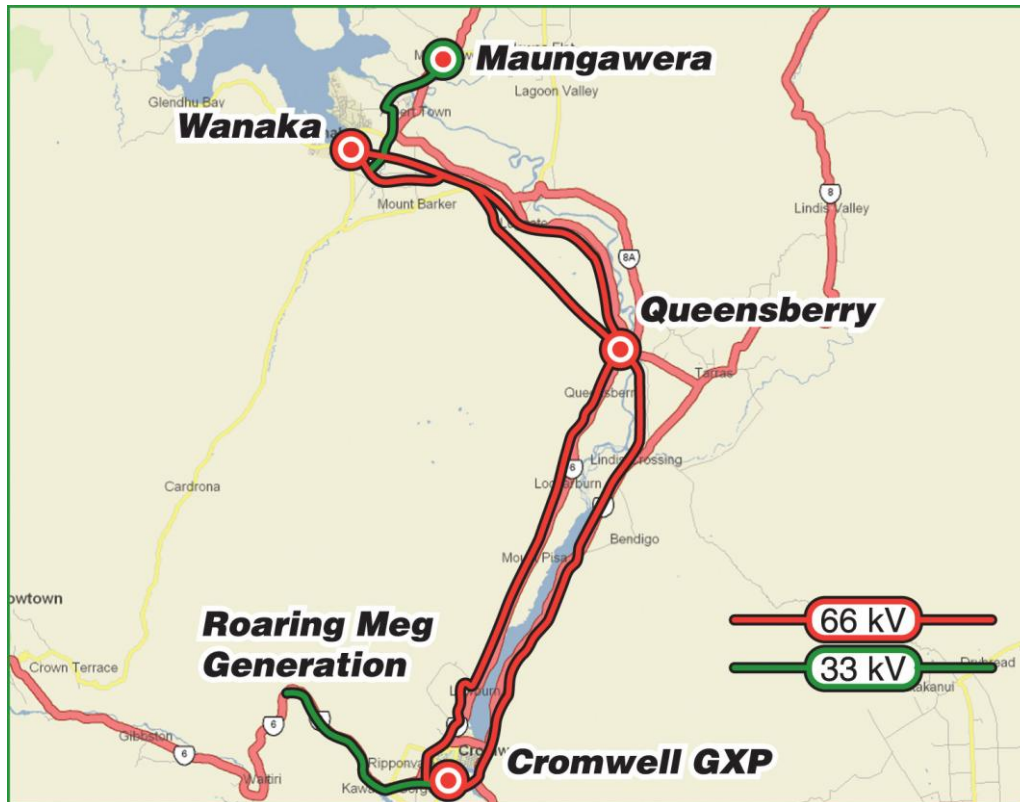


Figure 3.5 - Cromwell Subtransmission Network

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

Table 3.5 - Zone Substations in the Cromwell Area

3.3.4 Clyde Area

The Clyde area is supplied via two 33kV circuit breakers 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 33kV 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, are each supplied by a single 33 kV line. An overview of the network is shown in Figure 3.6 and zone substation details are in Table 3.6.

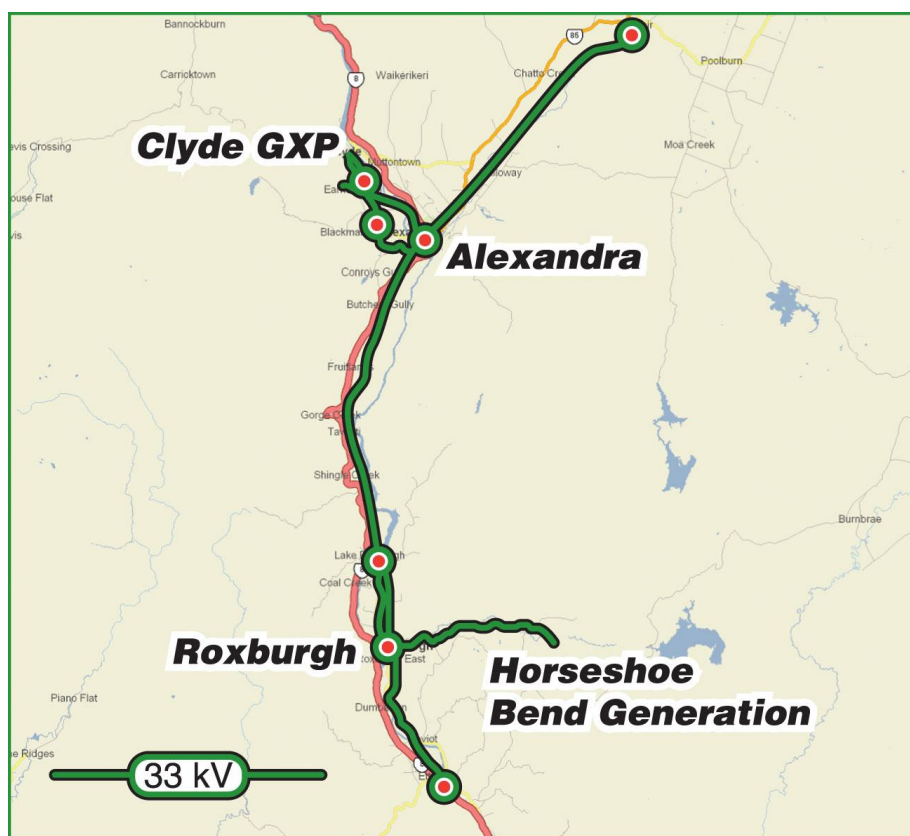


Figure 3.6 - Clyde Area Subtransmission

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

Table 3.6 - Zone Substations in the Clyde Area

3.4 HV Distribution (11kV and 6.6kV)

All HV mains are owned by Aurora, except where consumers specifically retain ownership.

3.4.1 Dunedin Area

HV distribution in the Dunedin area is via 182 HV feeders. Four zone substations; Berwick, Mosgiel, East Taieri, and Outram, have 11kV feeders and the remaining fourteen have 6.6kV feeders. The HV distribution voltage by location is shown in Figure 3.7 and the quantities by voltage are shown in Table 3.7. All feeders are radial with a high degree of meshing in the metro areas, except for the supplies to Otago University and the Hillside Workshops which have dedicated paralleled feeders. HV cable insulation in the Dunedin area is predominately PILC (86%) with the remainder being either XLPE (7%) or unknown (7%). For many years, all new cable has been rated for 11kV operation even when it operates at 6.6kV. Note that for this, and other assets described below, there is no plan to resolve unknown data as there is no economic case to do so.

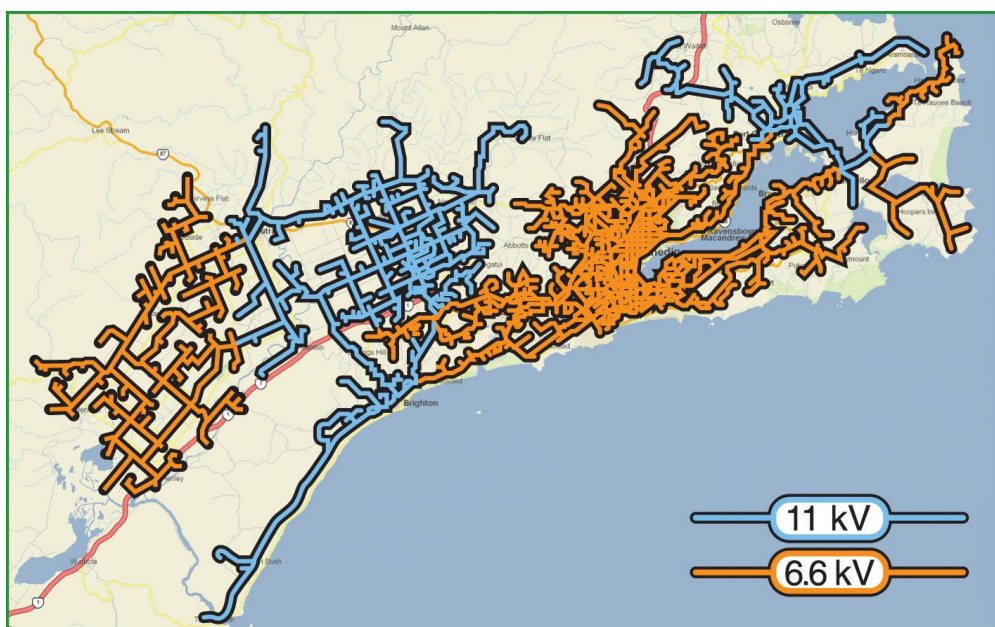


Figure 3.7 - Dunedin HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11kV	334	83%	17%
6.6kV	704	67%	33%
Total	1,038	72%	28%

Table 3.7 - Dunedin HV Distribution Quantities

3.4.2 Central Area

HV distribution in the Central area is via 59 feeders. All HV feeders are 11kV except for those in the Clyde area which are 6.6kV. All feeders are radial with limited interties to other feeders. The HV distribution voltage by location is shown in Figure 3.8 and the quantities by voltage are shown in Table 3.8. HV cable insulation in the Central area is a mix of PILC (27%), XLPE (66%) and unknown (7%). In Central, there is a significant quantity of rural HV cable, due to local authority requirements and the high number of rural lifestyle subdivisions.

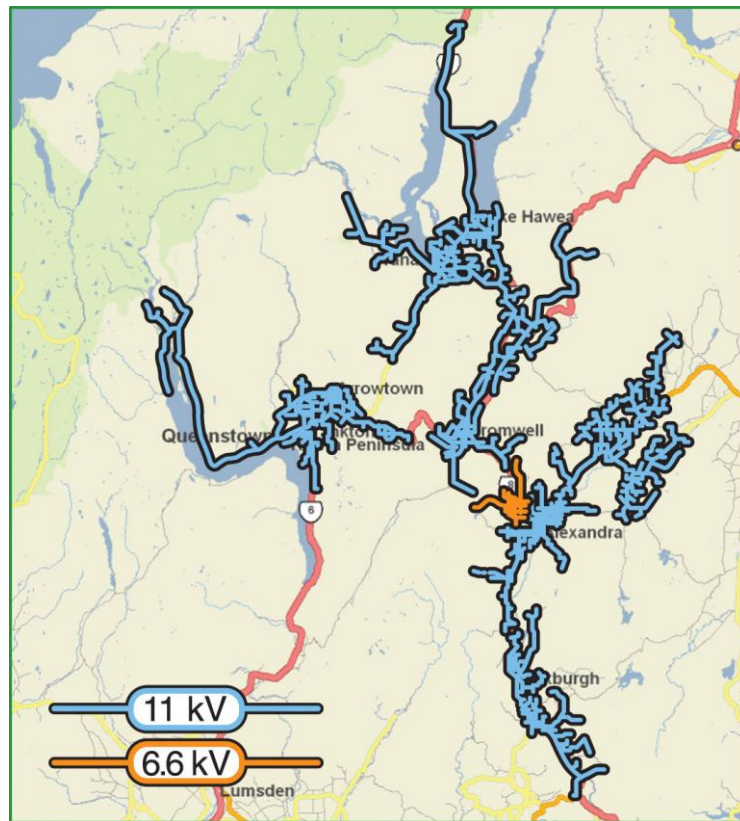


Figure 3.8 - Central HV Distribution by Voltage

Voltage	Km	% Overhead	% Underground
11kV	2,018	76%	24%
6.6kV	77	88%	12%
Total	2,095	77%	23%

Table 3.8 - Central HV Distribution Quantities

3.5 Distribution Substations (11/0.4kV and 6.6/0.4kV)

The quantities of each type of substation owned by Aurora are detailed in Table 3.9.

Substation Type	Count
Pole mounted	4,201
Pedestal mounted	8
Ground mounted	2,102
Underground	20
Total	6,331

Table 3.9 - Substation Count

3.5.1 Pole Mounted

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

3.5.2 Pedestal Mounted

Pedestal substations are used in the Central area only, and consist of a bushing/bushing transformer mounted on a concrete pedestal to facilitate open wire connection to the overhead network. They range in size from 150 to 500kVA. This configuration is no longer used and is being phased out due to latent safety concerns. Aurora intends to have the remaining pedestal mounted substations removed by June 2009.

3.5.3 Ground Mounted

Ground mounted substations range in size from 15 to 1500kVA and fall into the following categories:

- **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 1000kVA.
- **Micro (standard)** - these substations are used for low visibility. They range in size from 15 to 100kVA, 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 LV distribution switchgear. They were constructed in the 1960s and 1970s, generally have a 1000kVA 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 50kVA. This configuration is no longer used for new substations.

3.6 LV Distribution (0.4kV)

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. The quantities by area are given in Table 3.10.

Area	km	% Overhead	% Underground
Dunedin	972	80%	20%
Central	749	32%	68%
Te Anau	5.6	0%	100%
Total	1,726	59%	41%

Table 3.10 - LV Distribution Quantities

The reason that the 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

3.7 Secondary Assets

3.7.1 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. All zone substations, except the 1MVA Remarkables substation, have a Remote Terminal Unit (RTU).

3.7.2 Telecommunication Systems

In the Dunedin area, a pilot cable network, installed with 33kV cables, provides communication with twelve of the eighteen zone substations. Telecom facilities are used for the six zone substations not covered by the pilot network. In the Central area, data communication is via a combination of the Aurora owned VHF and UHF systems.

A limited UHF radio network exists in the Central area, principally providing for information transfer between Aurora and Pioneer Generation Ltd for operational and load management functions.

A VHF land mobile network is provided in Dunedin and Central and provides an extensive system for operational communications, and phase identification.

3.7.3 Load Management Systems

Dunedin Load Management

Load management in the Dunedin area is via 18 K22/Decabit 1050 Hz 11kV/6.6kV 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.

Central Load Management

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants; one in each GXP area. There are approximately 25,000 Decabit relays on the network, which are mainly owned by Electricity Retailers. The Central injection plants are controlled by a custom made system dating from 1996.

There is also a pilot wire system, controlled by interfacing Decabit relays installed at distribution substations, which supply approximately 2,000 consumers. This system is being replaced upon failure as there is no financial incentive to do otherwise.

3.7.4 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.

3.7.5 Mobile Substations/Generation

Aurora owns three 11kV/6.6kV/400V mobile substations. One 500kVA unit is based on Cromwell, with 300kVA and 500kVA units based in Dunedin. An additional 5MVA 66kV/33 kV/11kV/6.6kV mobile substation is undergoing commissioning. Aurora owns a mobile 500kW generator, which is based at the future Cardrona zone substation site.

3.7.6 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.

3.8 Asset Details by Category

The value of Aurora's assets by category, as derived from the 2008 ODV valuation of the network, is presented in Table 3.11, and each category is detailed below.

Asset Category	Quantity	RC	% by \$
Subtransmission	594 km	\$41,736,435	9%
Zone substations	36	\$96,638,950	21%
HV cables	782 km	\$72,476,897	16%
HV lines	2,353 km	\$61,315,237	13%
Distribution transformers	6,435	\$53,075,700	11%
Distribution switchgear		\$31,565,893	7%
Distribution substations	6,331	\$12,078,000	3%
LV distribution	1,726 km	\$76,403,484	16%
Service connections ¹	94,662	\$13,367,305	3%
Street lighting distribution	224 km	\$6,237,230	1%
System control		\$1,667,200	< 1%
Sundry		\$562,593	< 1%
Total		\$467,124,924	100%

Note 1 Now includes street light circuit connection points

Table 3.11 - ODV Value of the Aurora Network

The general condition of Aurora's assets is "fit for purpose". The underlying SAIDI (Section 8) is close to 90 minutes which compares very favourably with the performance of other like networks. Critical assets that have the potential to give concern, such as the Neville Street and Kaikorai Valley 33kV cables, are closely monitored.

3.8.1 Subtransmission Lines

The age profile of subtransmission lines (66 and 33kV) is shown in **Figure 3.9** based on conductor age.

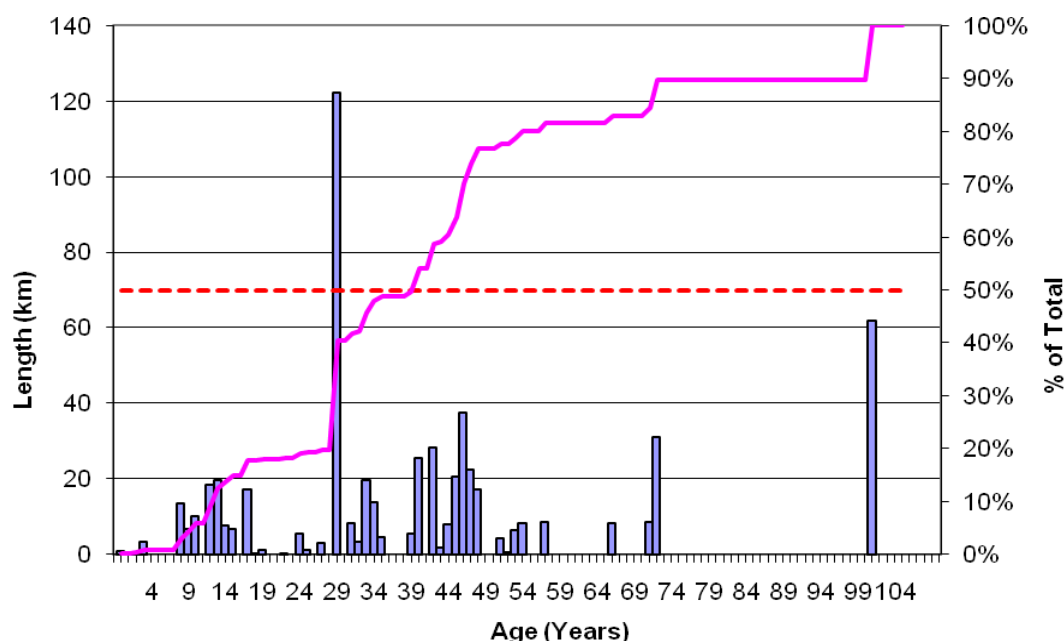


Figure 3.9 – 66 & 33kV Lines Age Profile (Total = 504km)

The lines shown at 101 years are the Taieri “A” and “B” lines to Waipori. These lines have had all of their original poles replaced, but the original conductor is still performing well.

All lines are in good condition and no significant expenditure is expected within the planning period, based on existing loadings. The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses, and its maintenance history. 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 and poles over 45 years.

3.8.2 Subtransmission Cables

The age profile of 33kV cables is shown in Figure 3.10.

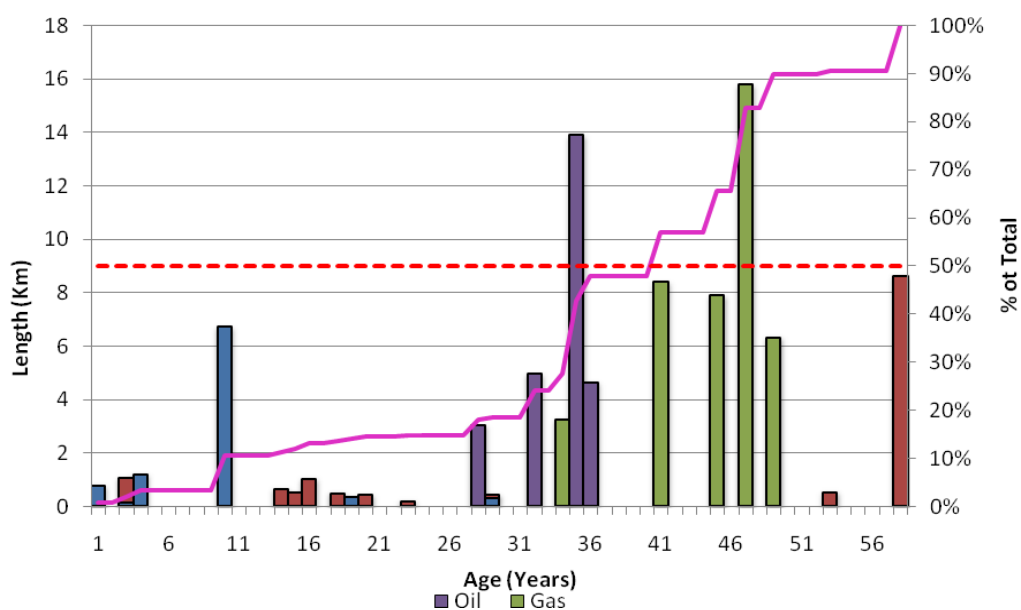


Figure 3.10 – 33kV Cables Age Profile (Total 90 km)

Following the Auckland CBD cable failures in 1998, an independent investigation was undertaken to confirm the condition of Aurora’s Dunedin 33kV cables, and review the maintenance practices employed for those cables. The report confirmed that most of the cables were in good condition, with the balance in fair condition. Partial discharge testing of 33kV cables has been used to monitor ongoing condition.

The 33kV gas insulated cables from the Halfway Bush GXP to Neville Street zone substation have experienced leaks. It is proposed to replace these cables within the planning period if the failure rate increases and makes it economic to do so. The Queenstown subtransmission cables were replaced in 2008 to meet ongoing growth.

3.8.3 Zone Substation Power Transformers

The age profile of zone substation transformers is shown in Figure 3.11. Transformers that are subject to moderate loading, minimal through faults, prudent monitoring and maintenance practices should last for at least 60 years. All power transformers have performed well to date and monitoring has not detected any latent concerns, with the exception of one transformer at Halfway Bush which had water ingress in November 2006, and another where Dissolved Gas Analysis (DGA) indicated that planned maintenance was necessary. The two 76 year old units at Berwick have been replaced since 31 March 2008. The Ward Street transformers are scheduled for replacement by winter 2010 in association with a major upgrade of the substation.

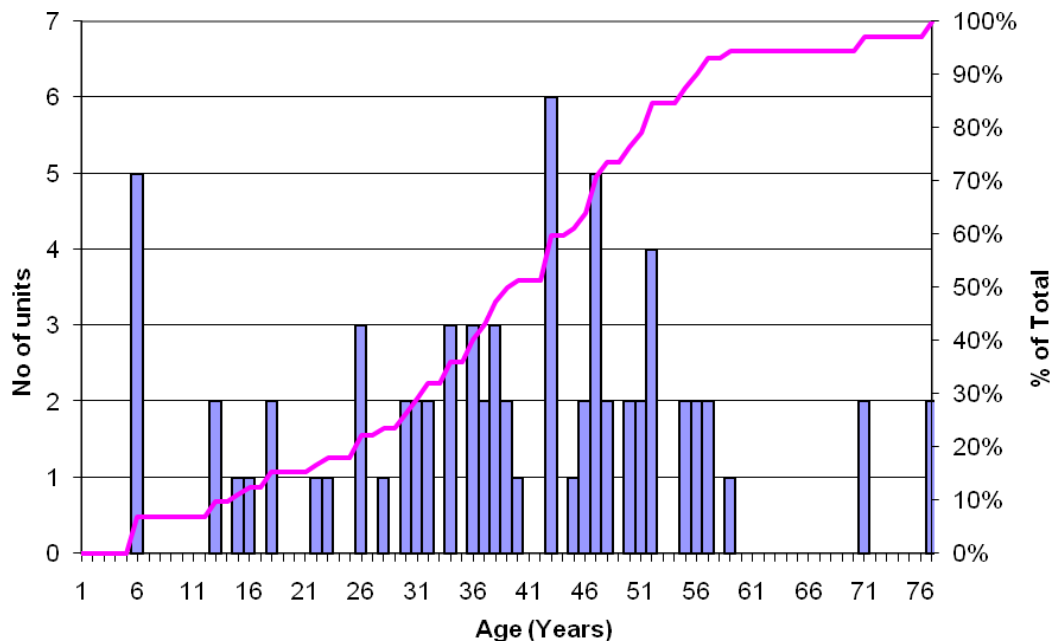


Figure 3.11 – 66 and 33kV Zone Substation Transformers Age Profile (Total = 73)

Note that the Berwick replacements are not shown as they were not fully complete as at 31 March 2008.

3.8.4 Zone Substation 66kV and 33kV Circuit Breakers

The age profile of 66 and 33kV circuit breakers is shown in Figure 3.12. The 33kV circuit breakers at five zone substations are more than 40 years old but are performing very well. Replacement of the circuit breakers at Mosgiel and Ward Street substations is scheduled during the planning period, and the circuit breakers at Alexandra and North East Valley are being closely monitored.

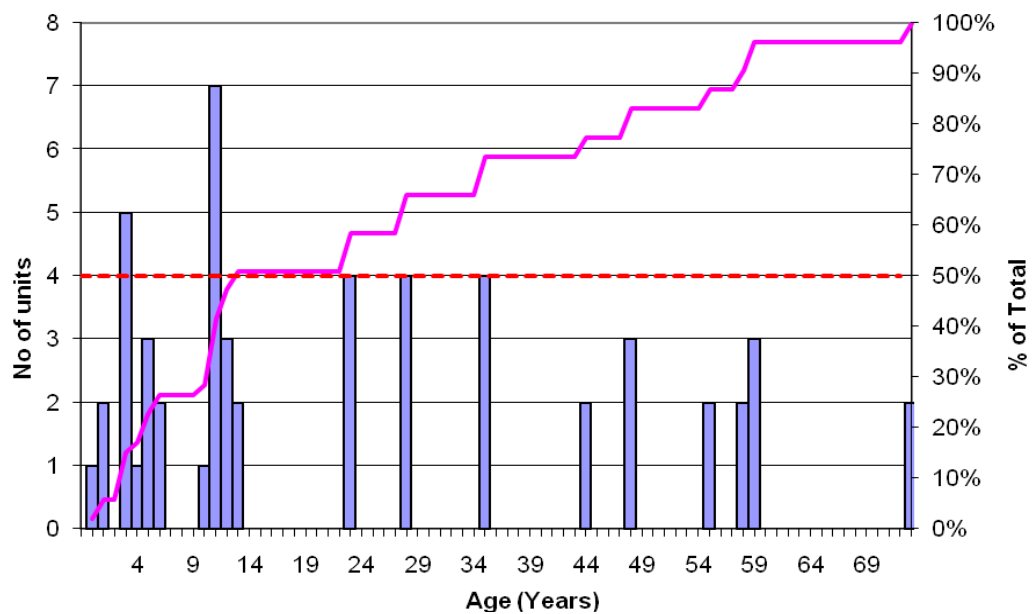


Figure 3.12 – 66 and 33kV Zone Circuit Breakers Age Profile (Total = 53)

3.8.5 Zone Substation 11kV and 6.6kV Circuit Breakers

The age profile of 11kV and 6.6kV circuit breakers is shown in Figure 3.13. Half of the circuit breakers are older than the ODV handbook limit of 40 years, but are performing adequately.

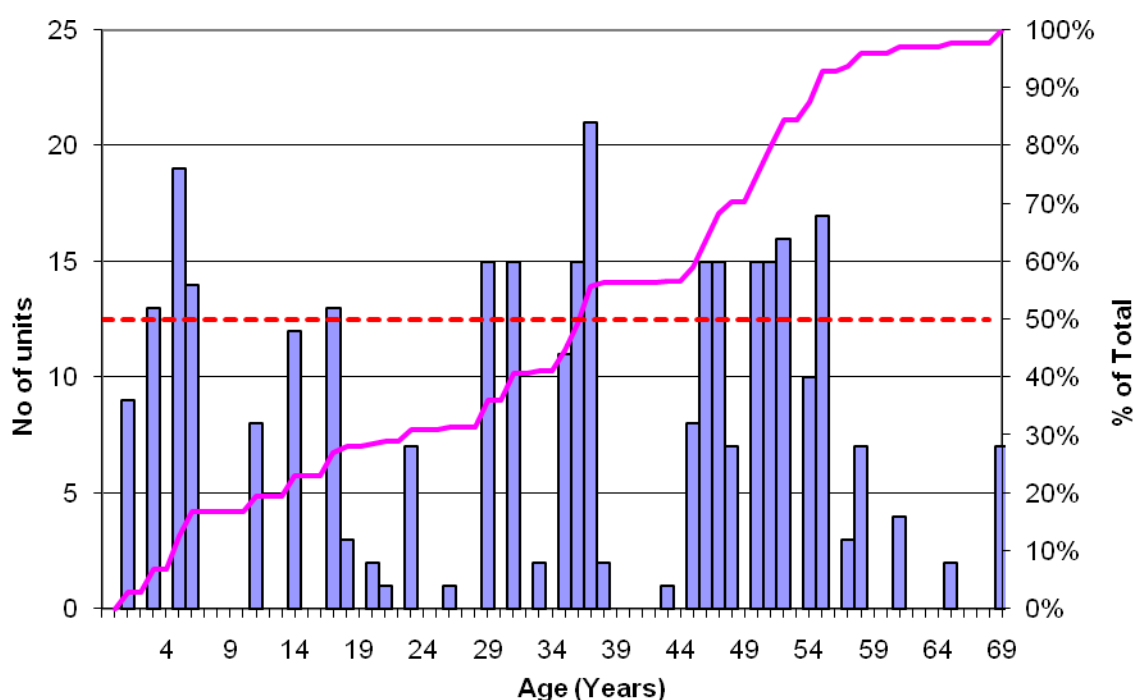


Figure 3.13 – 11 and 6.6kV Circuit Breakers Age Profile (Total = 325)

The oldest circuit breakers are listed in Table 3.12 along with anticipated (subject to economic evaluation) replacement dates.

Substation	Manufacture Year	Status	Number CBs	Year
Ward Street	1938	Approved	14	2010/11
Roxburgh	1950	Planned	1	2009/10
Frankton	1950	Planned	8	2009/11
Remarkables	1950	Monitor	1	
Neville Street	1953	Monitor	14	
Mosgiel	1954	Underway	10	2009/10
Halfway Bush	1956	Monitor	16	
Green Island	1957	Monitor	15	
Smith Street	1958	Monitor	15	
Earnsclough	1960	Monitor	1	
Dalefield	1960	Monitor	1	
Outram	1963	Monitor	8	

Table 3.12 – Scheduled Zone Substation Circuit Breaker Replacements

3.8.6 Load Control Equipment

In the Dunedin network area, the 11kV and 6.6kV load management ripple injection equipment at each zone substation dates from 1958, or from the date of construction of the substation if later. Replacement of these 18 plants with 33kV injection, or alternative technologies, is under consideration but is not yet confirmed. The 33kV injection plants in the Central network area are aged 16 (Cromwell), 20 (Frankton) and 22 (Alexandra) years. Notwithstanding any condition-based renewal, it is envisaged that the Frankton injection plant will require to be upgraded by 2014, due to network load growth. The Cromwell injection plant will be replaced in 2009-10 as part of consequential works caused by Transpower's upgrading of this GXP.

The age profile of load management equipment is shown in Figure 3.14.

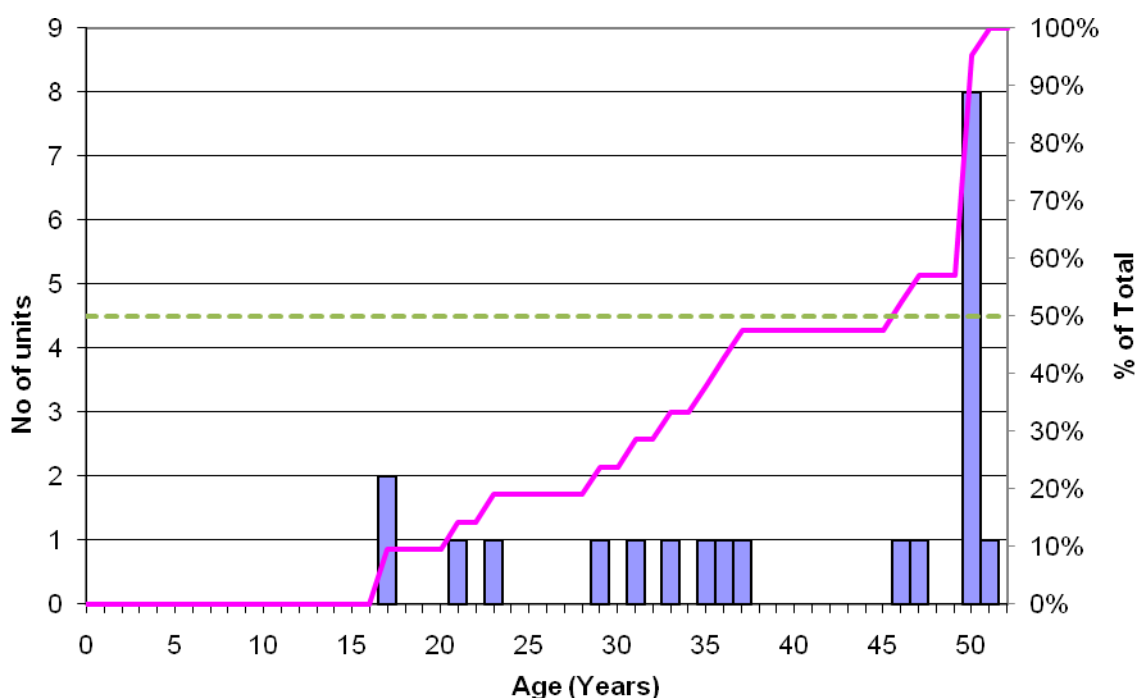


Figure 3.14 – Load Control Equipment Age Profile (Total = 21)

3.8.7 Zone Substation Protection Relays

Aurora does not have specific age profile data for the protection relays; however the age of the relays is generally the same as the associated switchgear. Protection relays are generally upgraded to modern numerical relays when the associated switchgear is replaced.

Relays are performing well operationally (no evidence of mal-operation) and under test, so Aurora sees no reason to intensively manage relays as a separate asset class.

3.8.8 SCADA Remote Terminal Units

The SCADA RTUs in Central date from 2000. In Dunedin the majority of the RTUs were installed in 1988. Dunedin RTUs have been very reliable, but face technical obsolescence due to their inability to use modern master station communication protocols, and to communicate with intelligent electronic devices such as modern protection relays. When substation switchgear and protection is upgraded, the station RTU is also upgraded.

3.8.9 Other Zone Substation Equipment

Battery banks at substations include flooded and sealed lead acid cells with various life expectancies. 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.

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.

3.8.10 Buildings, Grounds and Fences

There has been regular maintenance of substation buildings and grounds; however security fences are being upgraded.

3.8.11 HV Lines

Figure 3.15 details the age profile of HV lines by conductor age and pole age. Aurora has 2,353 km of HV lines and the age of 38.3 km (1.6%) has yet to be confirmed. As a result of growth in the Dunedin network area in the 1960s, and in the Central network area in the 1980s and 1990s, the age profile is relatively even up to 50 years old. 25% of conductor is aged more than 50 years. No significant change in maintenance expenditure on HV lines is expected over the planning period, as their underlying reliability is good.

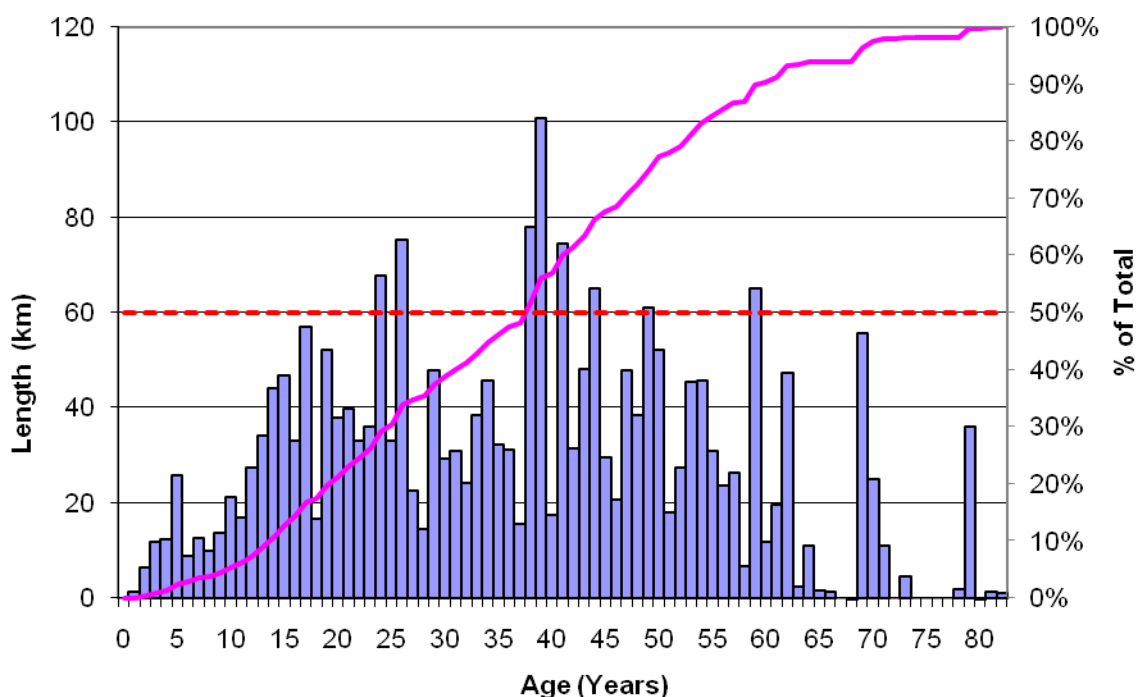


Figure 3.15 – 11kV & 6.6kV Lines Age Profile

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3.16. Aurora has 782 km of HV cable, of which the age of 32 km (4.0%) has yet to be confirmed. Deterioration of HV cable has not been a particular problem, 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.

No major replacements are necessary within the planning period.

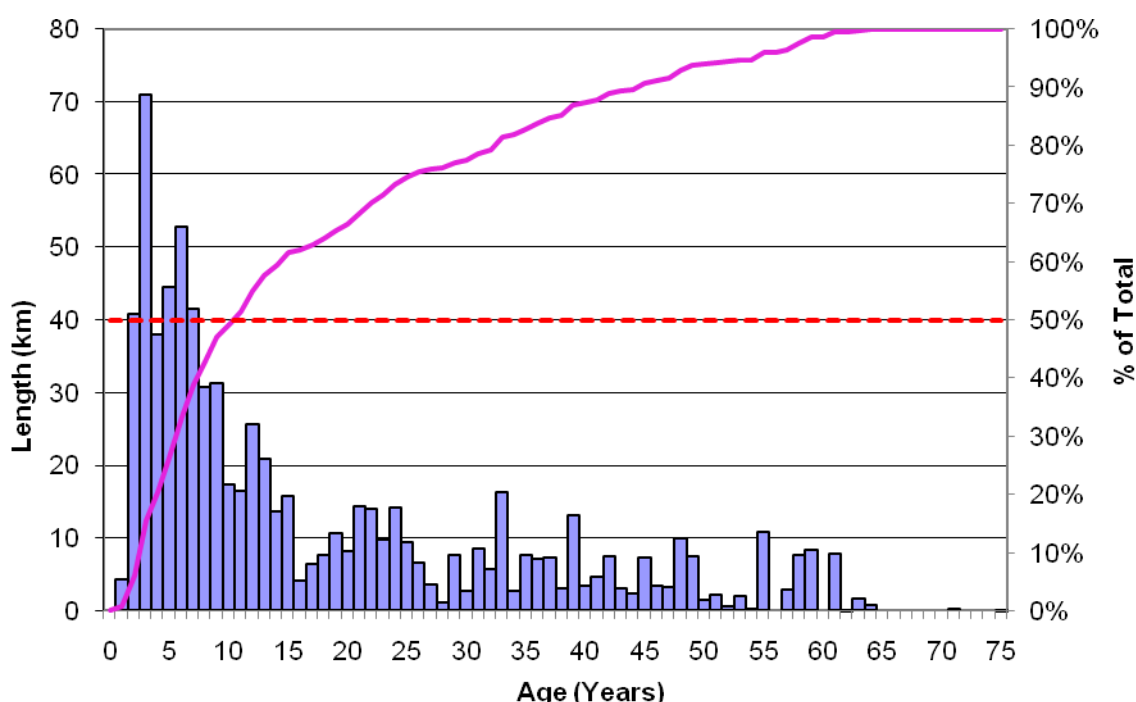


Figure 3.16 – 11 & 6.6kV Cables Age Profile (Total = 782 km)

3.8.13 Distribution Substations

Distribution substations comprise the transformer (sub-categorised in section 3.8.14, below), transformer pad, HV and LV fusing, and an earth mat. At 1 April 2008, there were 6,331 distribution substations on the Aurora network.

As at March 2008, 8 pedestal-mounted transformers remained on the Central network, (down from an initial total of 41), which are at risk in the event of a significant earthquake, and present a safety hazard. It is planned to have all of these replaced by June 2009.

In a historically abnormal flash-flood in February 2005, five underground distribution substations in Dunedin were flooded, and had to be off-loaded, with the subsequent failure of one transformer after the event. A programme is underway to seal and mechanically ventilate underground substations vulnerable to flooding.

3.8.14 Distribution Transformers

Figure 3.17, below, details the age profile of in-service distribution transformers. The age of only 26 units (0.4%) is unknown. While approximately 5% of the transformer population is older than the extended ODV life of 55 years, there is no history of age-related failures. Accordingly, only routine inspections and monitoring are necessary.

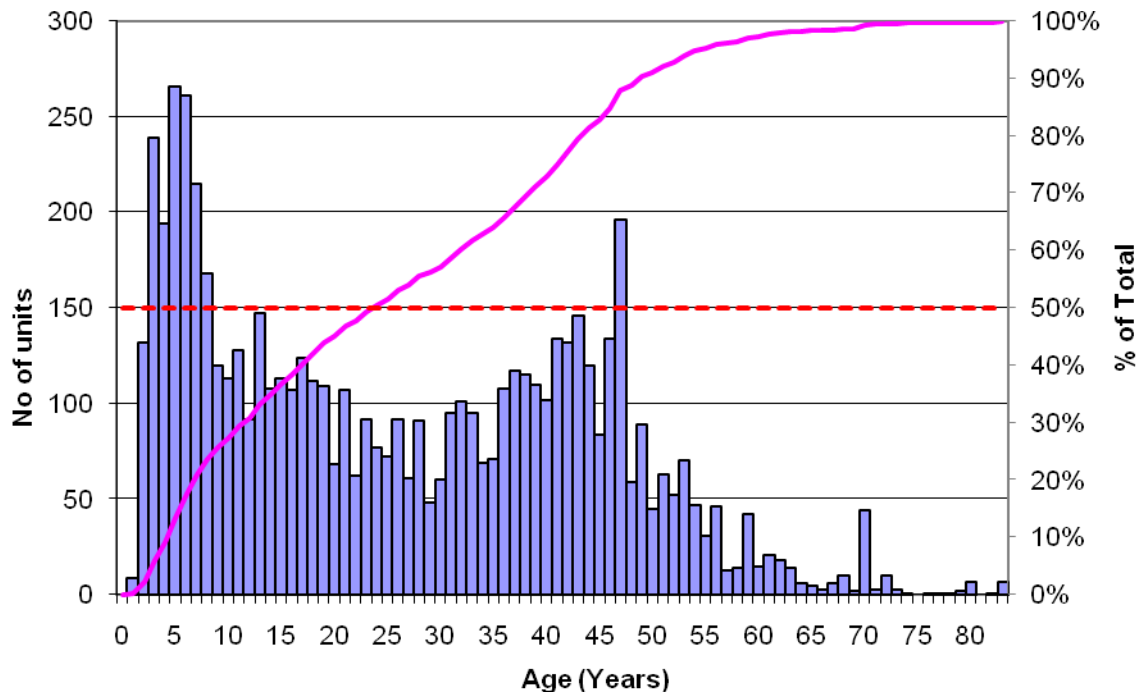


Figure 3.17 – Installed Distribution Transformers Age Profile (Total = 6435)

3.8.15 HV Regulators

Figure 3.18, below, details the age profile of regulators. The age profile is by regulator site; ie a site with three single phase regulators is treated as one unit.

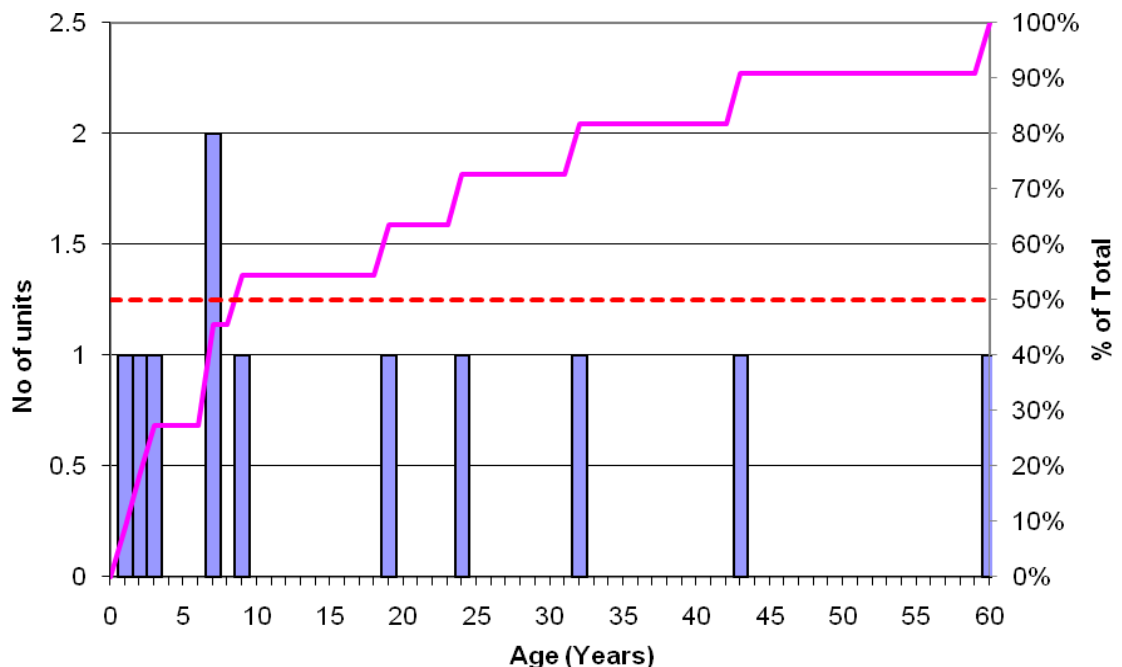


Figure 3.18 – HV Regulators Age Profile (10 Sites)

3.8.16 HV Auto-Transformers

Figure 3.19, below, details the age profile of auto-transformers. Nine auto-transformers (with a spare unit available) are used for the interconnection of 11kV and 6.6kV sections of the network. While these units have an average age greater than 38 years, they have been reliable and require only minimal maintenance.

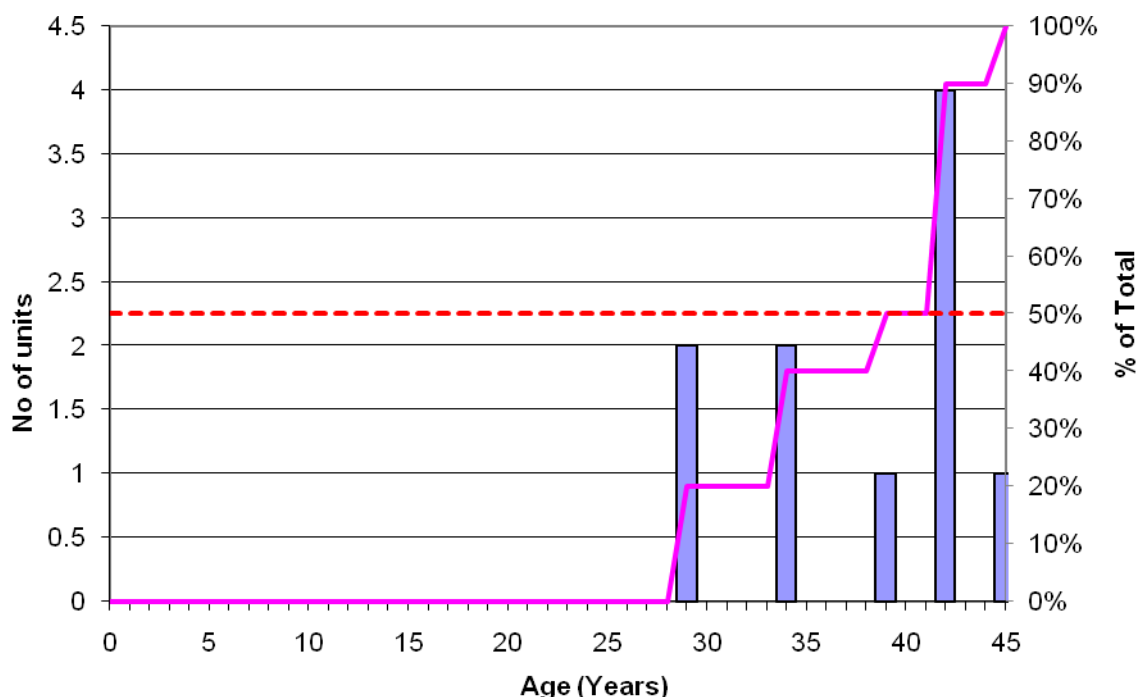


Figure 3.19 – HV Autotransformers Age Profile (10 Units)

3.8.17 HV Ground Mounted Distribution Switchgear

Ground mounted distribution switchgear consists of six different types, and the quantity by type is detailed in Table 3.13, below.

The age profile of ground mounted distribution switchgear is shown in Figure 3.20. Age data is not available for 7% of the units.

Switchgear Type	No of Units
Ground mounted 3 phase air fuse unit	112
HV oil ring main unit	489
HV oil fuse switch	289
Oil circuit breaker	32
Single HV oil switch	350
Vacuum circuit breaker	7
Total	1,279

Table 3.13 - Ground Mounted Switchgear by Type

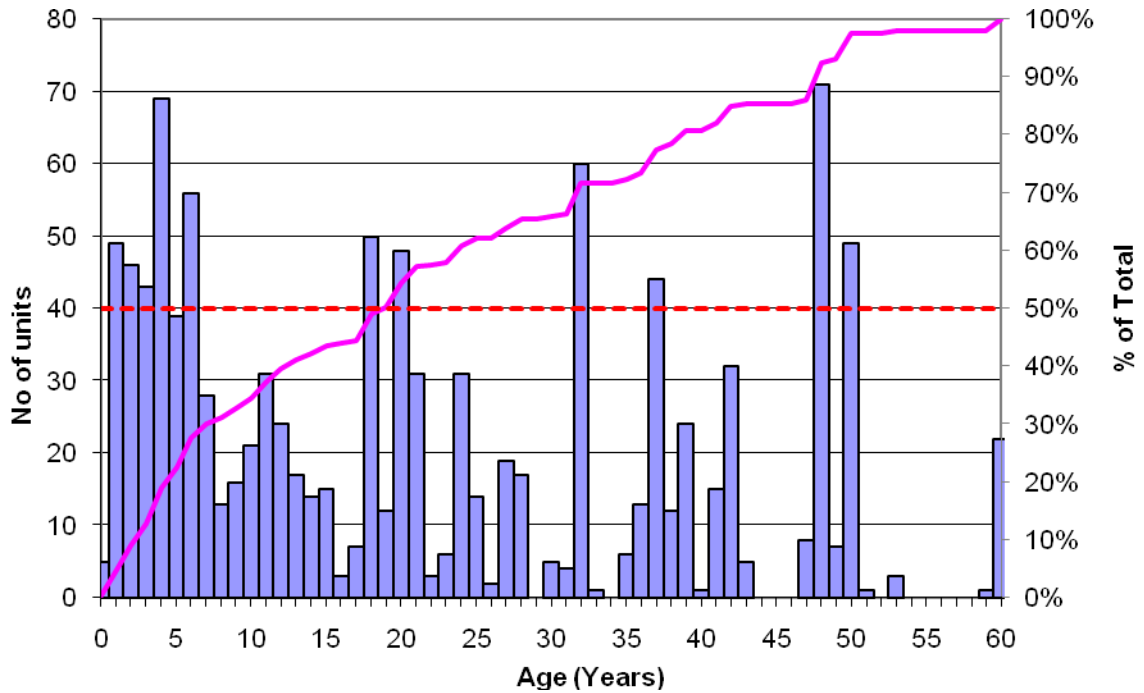


Figure 3.20 – HV Ground Mounted Switchgear Age Profile

3.8.18 LV Overhead Conductor

Figure 3.21 shows the age profile of overhead LV lines. Aurora has 950km of LV line, and the construction date of 202 km (21%) has yet to be confirmed. There are two types of LV overhead on the network, being predominantly open wire with a few kilometres of Aerial Bundled Cable (ABC).

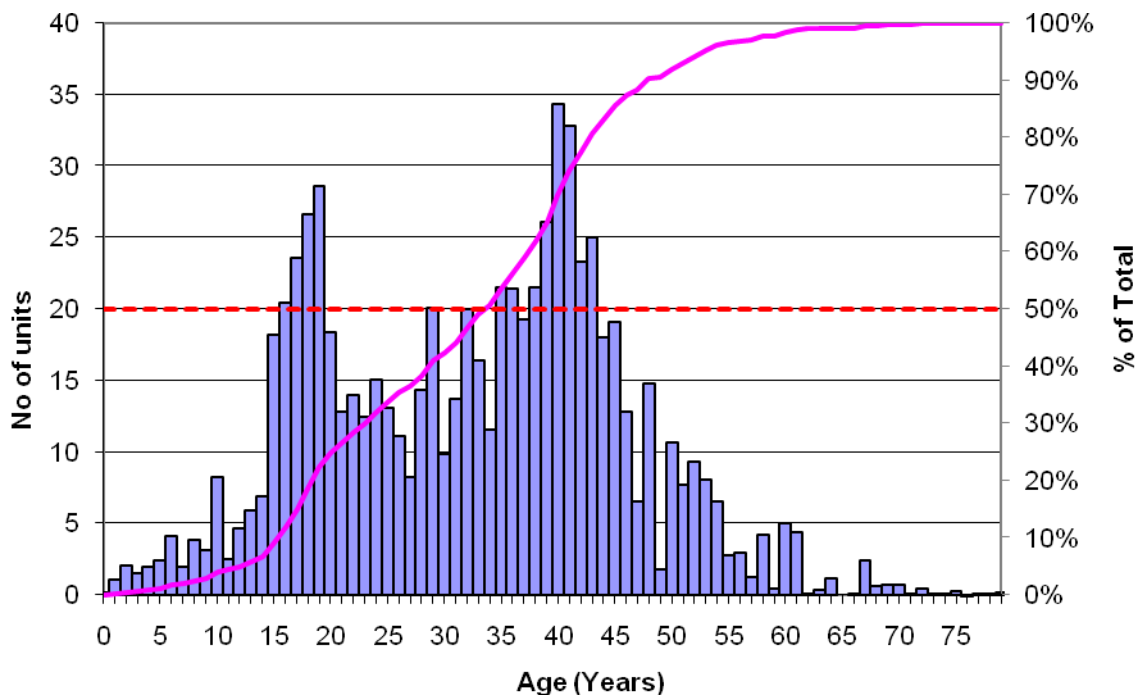


Figure 3.21 – LV Distribution Line Age Profile

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

Part of the grouping at the 15- 20 year age group is due to default date data, which is to be corrected when resources are available. Note that this is not a high priority.

3.8.19 LV Underground

Figure 3.22 shows the age profile of the underground cables. Aurora has 715 km of LV cable, of which the age of 45 km (6%) has yet to be confirmed as dating from original construction. Most LV cable is cross-linked polyethylene (XLPE). However, in the Dunedin CBD, paper-insulated lead covered (PILC) cable has been the norm.

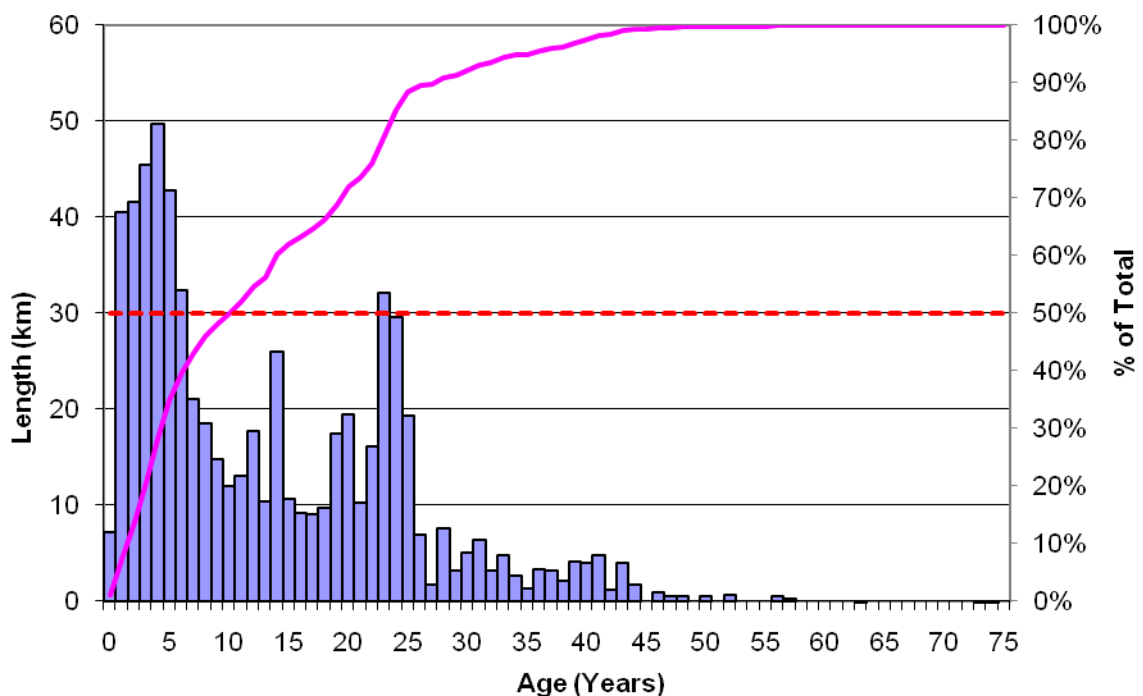


Figure 3.22 – LV Distribution Cable Age Profile

The recent boom in residential subdivision is evident.

The oldest LV cables show no sign of reaching the end of their economic lives.

3.8.20 Poles

Aurora has approximately 50,586 poles, of which only 96 (0.2%) poles do not have installation dates allocated.

Figure 3.23, below, details the age profile for HV and LV poles.

A condition-based inspection regime is in place, which indicates that the rate of renewal will double, at least, by the end of the planning period. Since 1990, 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. In light of communication with other network operators; it is likely that softwoods may be limited in the situations that they may be used.

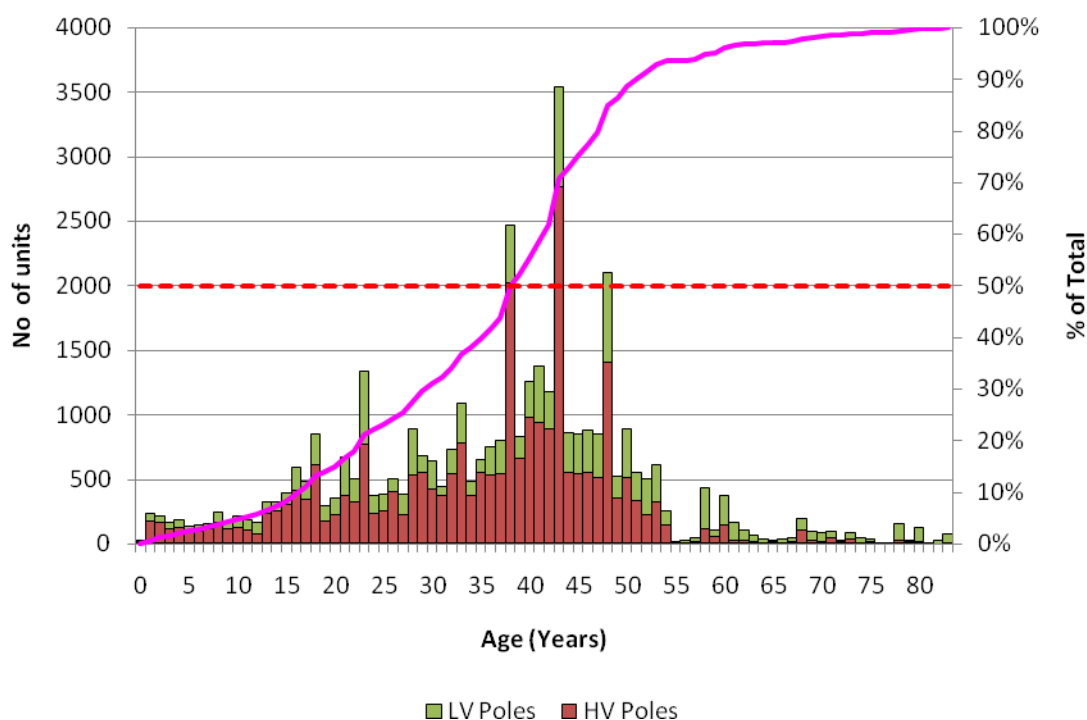


Figure 3.23 – HV and LV Poles Age Profiles

3.8.21 System Control Equipment

The Central region SCADA master station is a Lester Abbey system installed in 2000 with RTUs being installed from that time. The Dunedin master station is a Foxboro system for which a hardware and software upgrade was completed in March 2006. The Dunedin RTUs date from 1989.

3.9 Justification for Assets

All assets are justified by present or anticipated requirements, except for approximately 1.8% of assets by ODV value which have been “optimised” out for ODV purposes. Although such assets have been optimised out, many are still required to meet existing network standards; for example, fault limiting reactors. These assets require on-going monitoring and maintenance and, as such, represent a cost to the network. Until the cost of maintaining the status quo becomes higher than the cost to replace with the optimal network, these present network assets will remain in service.

Looking to the future, matching the level of investment in assets to expected growth and service levels requires the following issues to be considered:

- The need to accommodate future demand growth (noting that the ODV Handbook prescribes the number of years ahead that such growth can be accommodated).
- How asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.
- The asymmetric nature of under-investment and over-investment to be clearly understood ie over-investing creates service levels before they are needed, but under-investing can lead to service interruptions.

- The discrete “sizes” of many classes of components to be recognised; for example, a 220kVA load will require a 300kVA transformer that would be only 73% loaded. In some cases capacity can be staged through use of modular components.

In theory, an asset would be justified if the service level it creates is equal to the service level required. In a practical world of asymmetric risks, discrete component ratings, non-linear behaviour of materials, and uncertain future growth rates, Aurora considers an asset to be justified if its resulting service level is not significantly greater than that required, subject to allowing for demand growth and discrete component ratings.

Assets that were optimised are detailed below:

HV Distribution Switchgear

Twenty eight oil circuit breakers at distribution substations were optimised to oil switches or fuse switches. Oil circuit breakers that are no longer used were deleted. These were mainly associated with supply to trolley bus rectifier equipment, which has been removed.

HV Distribution

HV distribution lines and cables that were identified in the GIS as being “not in service” were optimised out. Typically, these are cables that have been laid in conjunction with other utility assets to minimise public inconvenience by avoiding the need to re-trench roads at a later date. The total quantity optimised was 10.7 km in the Central area, and 0.82 km in the Dunedin area. The Central area data, which relates to a historic GIS system, continues to be checked as resources are available.

LV Distribution

LV distribution lines and cables that were identified in the GIS as being not in service were optimised out. The total quantity optimised was 3.78 km.

Subtransmission

One of three circuits to the South City substation was optimised out because there are now only two transformers at South City. Neville Street cables were optimised to a shorter length to reflect new construction which would supply these substations from the South Dunedin GXP instead of the Halfway Bush GXP. Note that Ward Street cables are no longer optimised out, as studies have shown that the existing circuits are in their most economic configuration.

Pilots

54 km of pilot cables were optimised out in the Dunedin area mainly associated with the optimisation of the load management system.

Zone Substation Assets

At Alexandra substation, 33kV switches 3106 and 3104 were optimised out as they are for future use. At Wanaka substation, the circuit breakers and protection associated with feeders 2751 and 2757 were optimised out because they are for future land grant. At Fernhill substation, 33kV CB 3902 and associated protection for the future supply to Glenorchy was optimised out. The T2 bus section, incoming circuit breakers, and associated protection at South City substation were optimised out due to the removal of the T2 transformer.

At Frankton, the 7.5/15MVA T2 transformer was optimised to the same size as T1; ie, 5/10MVA.

Buildings at Neville Street and Ward Street were optimised to a smaller size. The South City building was optimised to a value two thirds of its replacement cost, to recognise that a replacement building would only accommodate two transformers and twelve outgoing feeders.

Nineteen unused HV feeder circuit breakers were optimised out.

Seventeen HV feeder circuit breakers in the Dunedin area were optimised out, where their projected five-year load was less than 30% of the feeder rating times 0.67, unless they were providing standby supply for large consumers.

Ward Street and Neville Street reactors and auto transformers were optimised out. This equipment will be required until the associated power transformers are replaced with new, higher impedance, units.

The 33kV bus work and switchgear at substations that would be reconstructed as transformer feeder stations was optimised out and yards optimised to a medium sized yard. These substations were Andersons Bay, Smith Street and Willowbank.

Transformers at Dunedin substations were optimised to the next standard smaller size where the projected 10 year load is less than the n-1 rating of the substation.

The 6.6/11 kV load control injection plant in Dunedin was optimised to the equivalent injection at 33kV.

4 Service Levels

Aurora's business is the delivery of electricity to more than 80,000 consumers. To ensure that it is providing a cost effective service and one that is in line with consumer expectations, Aurora surveys consumers regarding their expectations, consults with stakeholders, and benchmarks itself against industry standards.

Aurora sets a broad range of service levels for all stakeholders; ranging from capacity, continuity of supply, and restoration of supply following faults, to ground clearances, earthing, absence of interference, compliance with District Plans, and submission of regulatory disclosures. This chapter describes the service levels that Aurora delivers to its stakeholders, explains why it sets particular service levels in preference to others, and discusses how it sets the quantum of those preferred service levels.

It also specifically describes the service levels that Aurora is required to uphold for various regulatory bodies, and to contribute to the well being of the community at large.

The service levels defined in this section will be used to:

- (a) inform stakeholders, especially customers, of proposed levels of service;
- (b) focus Asset Management Plan strategies to deliver the required service levels;
- (c) enable customers to assess whether their service levels are appropriate, given the nature of the assets that provide the delivery service;
- (d) over time, provide a measure of the effectiveness of the actions taken in accordance with the AMP.

4.1 Customer Oriented Performance Levels

4.1.1 Consumer Surveys

User opinion on quality of supply issues is continuously surveyed by Aurora. The survey was commenced in 1999 and is continuous so that results are:

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

The survey is conducted directly with consumers because retailers appear to have little focus on quality issues at present, and because retailers may prove unable to reflect local preferences in the long term.

Table 4.1, below, summarises the survey results to-date. (2009 results are based on nine months of data.)

Aurora's Continuous Price Versus Quality Survey							
Results to 31 March	2003	2004	2005	2006	2007	2008	2009
Consumers Surveyed	4,327	4,554	4,641	4,603	4,752	4,800	2794
Response Rate	20%	18%	18%	18%	16%	17%	18%
Responses							
Prefer higher quality	9.3%	7.4%	6.7%	5.3%	5.9%	4.8%	6.9%
Prefer lower price	90.7%	92.6%	93.3%	94.7%	94.1%	95.2%	93.1%

Table 4.1 – Price Versus Quality Survey

Additionally, Aurora commenced biennial telephone interviews of approximately 400 consumers in 2006, with the intention of increasing the frequency to yearly intervals. The results from the surveys are shown below. The telephone survey involved 200 consumers in the Dunedin area and 200 in the Central Otago area, selected at random, and questions covered a range of price – quality and service related issues. The main results of the survey are set out below:

Aurora's Customer Telephone Survey 2008 and 2006							
No	Question	Dunedin		Central		Total	
		2006	2008	2006	2008	2006	2008
1	Price more important than quality	Yes 68%	65%	Yes 86%	59%	Yes 77%	62%
		Unsure 15%	11%	Unsure 2%	16%	Unsure 8%	14%
		No 17%	24%	No 12%	25%	No 15%	24%
2	Single most important issue relating to quality	No of interruptions 70%	40%	No of interruptions 71%	46%	No of interruptions 71%	43%
3	Accept 10% increase in line charges for 10% improvement in quality	No 68%	100%	No 75%	46%	No 71%	70%
		Unsure 12%	0%	Unsure 4%	0%	Unsure 9%	0%
4	Acceptance of rebate should increased supply not be achieved	Yes 68%	60%	Yes 88%	92%	Yes 76%	78%
		Unsure 12%	10%	Unsure 4%	0%	Unsure 9%	5%
5	Accept 10% decrease in line charges for say 10% more interruptions	No 44%	81%	No 80%	77%	No 64%	79%
		Unsure 16%	4%	Unsure 4%	7%	Unsure 9%	6%
6	Acceptable time-frame for restoration of supply (weighted avg)	2.8 hrs	2.2 hrs	1.6 hrs	2.6 hrs	2.2 hrs	2.4 hrs

Table 4.2 – Price Versus Quality Survey

Key points to emerge from the surveys are that;

- consumers generally do not wish to pay more for much improved reliability;
- the number of interruptions rates as the most important issue;

The key point to emerge from the survey is that whilst most consumers do not wish to pay more for significant improvements in reliability, consumers would prefer to have fewer interruptions.

These results validate Aurora's approach of analysing worst performing feeders, as described in Section 4.4.2 and that this AMP should focus on improvements to the 10 worst performing feeders, relative to their peers.

4.1.2 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.

4.1.3 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.

4.1.4 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.

4.2 Network Reliability

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.

Extensive data is collected by System Control, for both planned and unplanned interruptions to supply; including the duration of the outage, number of consumers affected, and cause. This information provides all the input data necessary for calculating Aurora's reliability statistics. It is important to note that one-off events can unduly influence the results for any one year, and that the long-term trend is more important and reflects the overall reliability of the assets.

Set out in Figures 4.1 and 4.2 below, are graphs of past performance for the Dunedin and Central Otago networks, using the SAIDI measure. The graphs show the average minutes without supply per customer for planned events, the largest unplanned event, and all other unplanned events.

Note: The graph for the Central Otago area includes the period from 1993 to 1999 when Central Electric owned this network area.

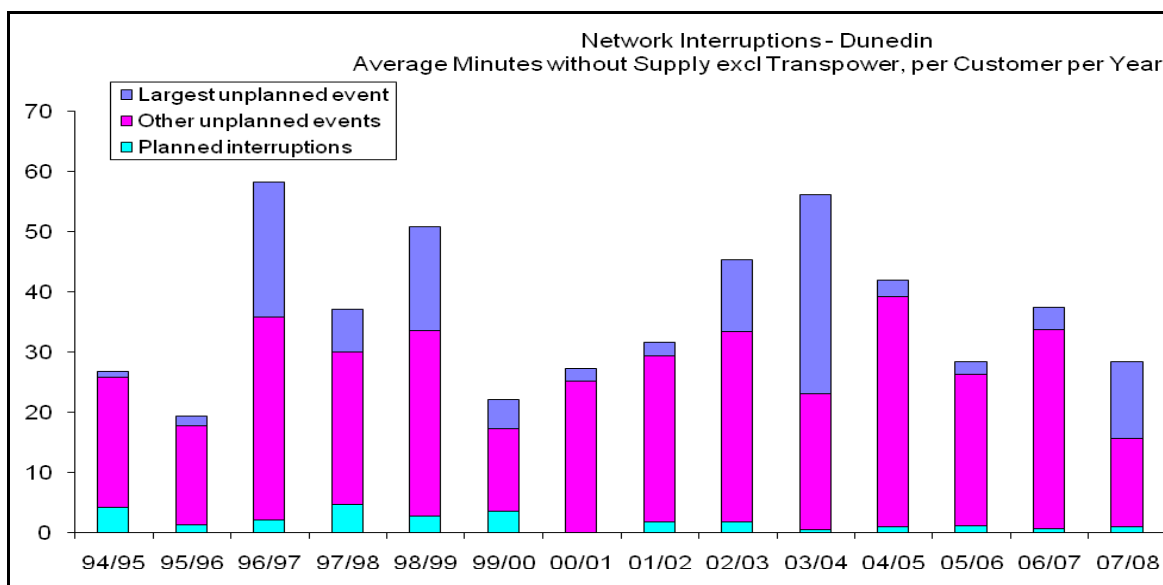


Figure 4.1 - Network Interruptions - Dunedin

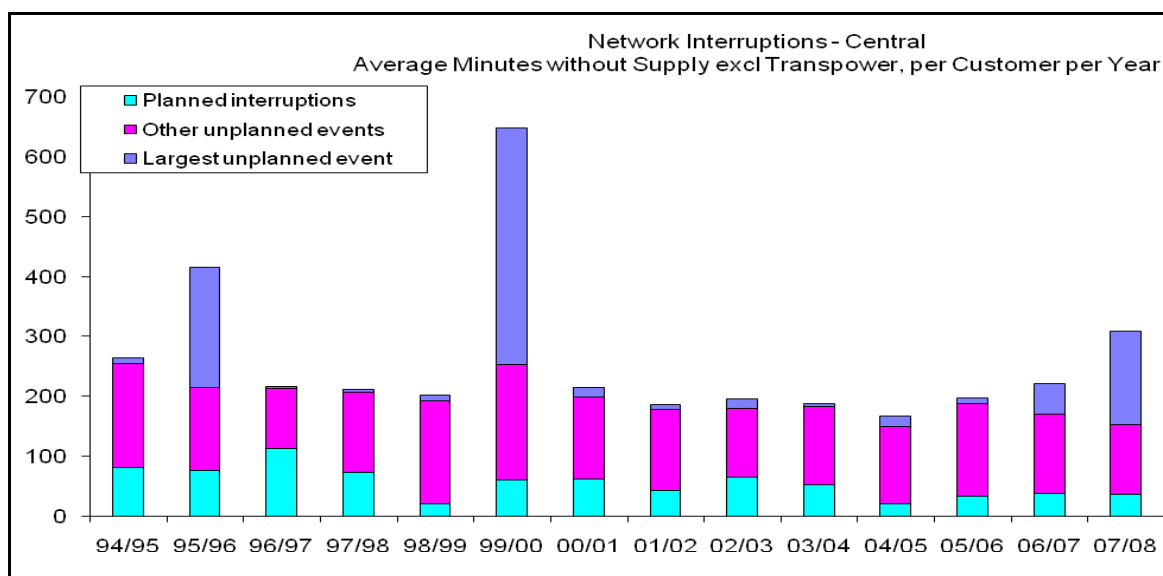


Figure 4.2 - Network Interruptions - Central

In 1999/2000, an extreme weather event consisting of very high winds, combined with heavy snow falls, resulted in widespread outages. In 2007/2008, gale force winds in Central Otago resulted in multiple outages, with both Cromwell – Wanaka 66kV circuits affected for 10 hours.

4.3 Primary Customer Service Level Targets

From the above surveys and consultation, Aurora has confirmed that providing a reliable and secure network for electricity delivery is the primary requirement, and that consumers do not wish to have any reduction in service from that currently provided.

- consumers want service continuity (“keeping the lights on”)
- consumers want fewer interruptions especially in rural areas.

In summary, Aurora believes it has a strong community mandate to focus on supply continuity.

Aurora uses the internationally accepted supply reliability measures of SAIDI and SAIFI; the 10-year target levels of which are set out in Table 4.3 and Table 4.4, below. SAIDI is the primary measure chosen to monitor overall asset, since it combines both interruption frequency and interruption duration. This AMP provides for incremental improvement of SAIDI by reducing SAIFI, especially for those consumers that experience high levels of interruption.

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Unplanned	72	71	71	70	69	68	68	67	66	65
Planned	15	15	14	14	14	14	13	13	13	13
Total	87	86	85	84	83	82	81	80	79	78

Table 4.3 – Network Performance Target (SAIDI) (minutes)

Within this strategy, analysis will continue to focus on improving the worst components of performance, and to mitigate the occurrence and impact of significant events. This includes analysis at the HV feeder level in order to identify economic opportunities to improve the worst performing feeders.

Another important service level is unplanned SAIFI, which is chosen due to the expressed consumer preference for fewer faults. The 10-year target for unplanned SAIFI is shown in Table 4.4 – Network Performance Target (SAIFI), below:

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Unplanned	1.31	1.29	1.27	1.26	1.25	1.24	1.24	1.22	1.20	1.19

Table 4.4 – Network Performance Target (SAIFI)

Aurora also recognises that these measures are somewhat academic and meaningless to individual stakeholders, so, in practical terms, individual consumers can expect the supply reliability levels stated in Table 4.5, below.

These levels of service are, in most cases, the results of previous system designs based upon deterministic forms of security guidelines. This is a useful rule-of-thumb approach to network design, but it is dependent on engineers' perceptions of consumers' needs (for example - larger load groups and "urban" feeders are generally assigned higher standards, without the basis of the choice being explicit) and has historically led to over-investment. Such a deterministic approach was used in the past by Aurora for the Dunedin City area, but future decisions on asset replacement and upgrade are being made using a demand-side driven, probabilistic, approach. This approach is more sophisticated, is facilitated by technology available today and, in Aurora's view, will lead to better asset utilisation and, thus, lower costs while meeting consumer expectations.

General Location	Target for Sustained Outages	Actual 2007/08 (No of feeders exceeding performance criteria) (No of feeders in that category)
Otago University, Hillside Workshops	No more than 1 outage of less than 4 hours every 5 years	0 of 6
Dunedin urban CBD	No more than 1 outage of less than 4 hours every 5 years	0 of 33
Dunedin urban suburbs	No more than 2 outages of less than 4 hours each year	8 of 106
Taieri Plains, Otago Peninsula	No more than 4 outages of less than 4 hours each year	5 of 26
Major urban areas in Central (Alexandra, Queenstown, Cromwell, Wanaka)	No more than 2 outages of less than 4 hours each year	6 of 18
Smaller towns in Central (Arrowtown, Roxburgh, Clyde, Ettrick, Omakau, Lake Hawea, etc)	No more than 4 outages of less than 6 hours each year	2 of 13
Rural areas in Central	No more than 10 outages of less than 6 hours each year	9 of 61
Remote rural areas in Central	No more than 20 outages each year	0 of 4

Table 4.5 - Fundamental Reliability Targets by Consumer Location

In the year ended 31 March 2008, 4,107 (6%) urban consumers experienced more than four interruptions and 2,863 (26%) rural consumers experienced more than 10 interruptions. Most rural consumers experiencing high numbers of interruptions are supplied from reclosers and, hence, many of the interruptions will be for relatively short periods. From recent customer surveys, Aurora is aware that, for many consumers, frequent interruption with fast restoration is more annoying than fewer interruptions but slower restoration. This is a factor that Aurora now takes into account when positioning reclosers in HV feeders.

4.4 Secondary Customer Service Level Targets

Aurora has a number of service level targets which it regards as secondary to the primary service levels.

4.4.1 Faults per 100km of HV Circuit

Physical asset performance targets, such as faults per 100 km of HV circuit, are supply-side measures, and are secondary to SAIDI and SAIFI; however, they do provide segmented information to assist Aurora when making asset management decisions. Table 4.6, below, describes the target level of faults per 100km of HV circuit, and the actual performance achieved for the 2007/8 year.

Measure	Indicator	Target Level	Actual 2007/08
Faults per 100km HV	No of incidents per year	11.1	11.7
Faults per 100km HV UG	No of incidents per year	2.5	1.8
Faults per 100km HV OH	No of incidents per year	13.5	14.6

Table 4.6 - Targeted and Actual Performance - Faults per 100km of HV Circuit

4.4.2 Improve the Performance of the 10 Worst HV Feeders

From consumer surveys, many rural consumers expressed a strong preference for fewer interruptions. Over the last 10 years, Aurora has focused upon installing SCADA systems into the Central Otago network and installing remote controlled switches into the many long rural HV feeders, in an effort to reduce the number of consumers interrupted when an unplanned interruption occurs, and then to restore supply as soon as possible. Whilst these efforts have reduced the average restoration time, the number of interruptions for some feeders is now becoming the main issue of concern.

In order to address these concerns, Aurora has selected the following feeders (refer Table 4.7) for attention over the next two years.

Area	Improve Reliability	Measure	Target Level
Arrow Junction	OT7652	Reduce number of interruptions	20% improvement
Bannockburn	CM821	Reduce SAIDI and number of interruptions	10% improvement
West Cromwell	CM832	Reduce number of interruptions	10% improvement
Hawea Flat	MA244	Reduce SAIDI minutes	10% improvement
St Bathans	OM634	Reduce number of interruptions	10% improvement
Poolburn	OM679	Reduce number of interruptions	10% improvement
Omakau West	OM699	Reduce number of interruptions	20% improvement
Lower Peninsula	PC3	Reduce SAIDI minutes	20% improvement
Aramoana	PC5	Reduce SAIDI minutes	10% improvement
Glenorchy	QT5202	Reduce SAIDI minutes	20% improvement

Table 4.7 - Targeted Improvement in the 10 Worst Performing Feeders

4.4.3 Financial Efficiency Targets

Aurora strives to ensure that its operating costs are low compared to others in the NZ distribution sector. The chosen financial efficiency measures, shown in Table 4.8 below, are based around the measure of total operating costs to supply consumers per kWh.

Service Criteria	Service Definition	Target	Actual 2006/07
Operating efficiency	Total direct and indirect charges per kWh delivered	Lowest quartile for all networks	5 th lowest out of 28 networks

Table 4.8 - Cost Efficiency Measure

4.4.4 Energy Delivery Efficiency Targets

Aurora's projected energy delivery efficiency measures are shown in Table 4.9, below:

Service Criteria	Service Definition	Target	Actual 2007/08
Load factor	Energy into network / peak kW hours per year	52%	54.7%
Loss ratio	Energy into network less energy delivered / energy into network	6.0%	5.6%
Capacity utilisation	Peak network kW / installed distribution transformer capacity kVA	30%	33.7%

Table 4.9 - Energy Delivery Efficiency Measures

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. Thus, it is not appropriate to compare Aurora with, say, a North Island network which will have a flatter load profile and a corresponding higher load factor. Pricing signal efficacy notwithstanding, 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.

4.4.5 Restoration of Electricity Delivery Following a General Network Failure

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:

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

Payments are not made if the fault is due to extraordinary climatic conditions, civil emergencies, Transpower initiated, or certain third party events.

These payments apply to the standard Use-of-System Agreement with retailers, and other arrangements can be negotiated. To date, no party has sought any alternative compensation arrangement.

The actual spend on service failure payments (effectively a line charge reduction for reduced service) over recent years is detailed in Table 4.10, below:

Year to 30 June	Events	Consumers Affected	Total Paid	Percent 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%

Table 4.10 - Historic Service Failure Payments

As a result of the modest level of such payments, and the excellent delivery service provided, the quantum of compensation paid is insufficient to materially affect network design, and applies only modest pressure to operational decisions. Of far greater significance in changing behaviour is the cost-of-interruption charge Aurora applies to approved construction and maintenance contractors for planned outages, which is designed to maximise the use of live line techniques, and other innovative work practices.

4.5 Tertiary Customer Service Levels

4.5.1 Fault Calls

Since the separation of the line and energy businesses, Aurora has not operated a call centre capable of answering multiple fault calls. It does provide a 24 hour service for direct fault calls and emergency contact; however, this service has a limited capability and consumers are encouraged to call their retailer for up-to-date information on fault restoration.

4.5.2 Power Quality or Service Interruption Investigations

Aurora will respond to enquiries regarding power quality or service interruption investigations within 7 working days. 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.

4.5.3 Voltage Range

Minimum and maximum voltage is set by regulation for the protection of consumer appliances, but excludes "momentary" fluctuations. Voltage excursions outside of the statutory range will occur because of equipment failure, environmental effects (for example - lightning), or unexpected loads, and all can require solutions that take time. Voltage excursions will normally be reported by consumers for low voltage, due to rising loads or failing conductor joints, and occurs during winter when loads are highest. Often the problem has abated, until the following winter, before Aurora can confirm the cause or make additional investment, where this is necessary. Accordingly, Aurora sets a target for the maximum number of outstanding voltage complaints of ten per ten thousand consumers per annum; ie, 80 voltage complaints per year. Table 4.11, below, details the actual frequency of voltage complaints against target.

Aurora actively monitors progress to resolve complaints. If there are delays to remedying the issue, the usual impediment to meeting them is gaining Local Authority agreement to the location of equipment; for example, transformer placement.

Measure	Service Level	Target	Actual 2007/08
Voltage complaints	No of valid voltage complaints per year	Less than 10 per 10,000 connections	1.6 per 10,000 connections

Table 4.11 - Reported Voltage Complaints

4.5.4 Customer Service

Because Aurora has contracted out management of its assets, Aurora monitors *DELTA*'s performance to ensure appropriate customer service levels are maintained for such matters as answering telephones and correspondence. Aurora is also a founding member in the Electricity and Gas Complaints Commission scheme and is committed to resolving consumer issues in a responsible manner. Table 4.12, below, details Aurora's general customer service levels.

Measure	Service Level	Service Guarantee	Valid Claims 2007/08
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 for exceeding the time-frame	Nil
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 for exceeding the time-frame	Nil
Notification of planned service interruption	Missing notification of planned interruption	\$20 per ICP per missed communication	Nil

Table 4.12 - Customer Service Levels

4.6 Regulatory Service Levels

Various Acts and Regulations require Aurora to deliver a range of outcomes within specified timeframes, such as:

- restraining prices during each financial year to that prescribed by the price path threshold;
- ensuring that SAIDI and SAIFI do not materially decline from the 5-year average to 31 March 2003;
- publicly disclose an AMP each year;
- publicly disclose prescribed performance measures each year.

The complete derivation of these measures will be included in the Financial and Information Disclosures and the Threshold Disclosures published on Aurora's website www.electricity.co.nz.

4.7 Service Levels for Other Stakeholders

Aurora also creates a number of service levels that benefit other stakeholders such as safety, amenity value and absence of electrical interference.

4.7.1 Safety

There are various legal requirements for assets (and consumers' plant) to adhere to certain safety standards, which include earthing exposed metal and maintaining specified line clearances from trees and from the ground. These requirements include:

- Health & Safety In Employment Act 1992;
- the amended Electricity Act 1992 setting out the requirements for safety management systems;
- Electricity (Hazards from Trees) Regulations 2003;
- maintaining Safe Clearances From Live Conductors (NZECP34:2001);
- power system earthing (NZECP35:1993).

The need to protect both the workforce involved with the operation and maintenance of Aurora's assets, and the general public, requires management of the inherent hazards of electrical equipment. Industry safety rules establish the principles for safe work and Aurora's operating and maintenance standards detail the procedures for meeting these principles in various situations.

The replacement programme for plant and equipment ensures that unsafe items are replaced at the earliest opportunity, if defects cannot be eliminated. To protect the public, Aurora takes particular care of its subtransmission and distribution lines, through its maintenance programmes, by ensuring that vegetation is maintained clear from lines. Similarly, zone substation fences and gates, distribution substations, LV pillars, and other equipment enclosures are maintained in good order.

Aurora's key safety measures are detailed in Table 4.13, below:

Measure	Indicator	Target Level	Actual 2007/08
Safety of public	No of incidents per year	Zero incidents per year	0
Safety of personnel	No of incidents per year	Zero incidents per year	0
Safety of network assets	Compliance with standards	All significant site hazards removed or mitigated	0

Table 4.13 - Network Safety Levels

4.7.2 Environmental Management

There are a number of requirements that limit where and how overhead power lines are built:

- the Resource Management Act 1991;
- the operative Dunedin City, Central Otago and Queenstown Lakes District Plans;
- relevant parts of the operative Otago Regional Plan;
- Land Transport requirements.

In general, new assets will be required to be installed underground, in many areas, which is significantly more expensive, and may also raise reliability levels beyond what consumers generally expect and are prepared to pay for.

Many of Aurora's assets are in environmentally sensitive areas. Maintenance programmes include; the repair and maintenance of oil filled equipment (such as transformers and circuit breakers) to prevent leakages, the upkeep of noise-reducing components, and appropriate landscaping and/or revision of land use.

In addition, some of Aurora's assets are in ecologically sensitive areas where design of the asset needs to take into account the local environment. The District Plans of local authorities also set out minimum standards, and in many cases assets are required to be located underground.

A specific instruction covers the handling of sulphur hexafluoride (SF₆) gas used as an insulating medium in some equipment. Polychlorinated biphenyls (PCBs) have been eliminated from Aurora's equipment. No breaches of the RMA have occurred.

Table 4.14, below, describes Aurora's principal environmental performance measures.

Measure	Indication	Target Level	Actual 2007/08
SF ₆	No of incidents per year	Zero incidents per year	0
PCBs	No of incidents per year	Zero incidents per year	0
Oil spills	No of incidents per year	Zero incidents per year	0

Table 4.14 - Environmental Performance Measures

4.7.3 Electrical Interference

Under certain operational conditions, assets can interfere with other utilities, such as telephone wires and railway signals, or even with the correct operation of Aurora's own equipment or customers' plant. The following two codes impose service levels:

- harmonic levels (NZECP36:1993);
- SWER load limitation to 8A (NZECP41:1993).

4.8 Justifying Service Levels

Aurora justifies its service levels in several ways:

- on the basis that the majority of consumers have expressed a preference for maintaining similar levels of continuity and restoration, in return for paying similar line charges;
- by what is achievable within Aurora's constrained revenue;
- by the physical characteristics and configuration of the network, that embody an implicit level of reliability which is expensive to significantly alter (but which can be altered if a consumer or group of consumers agrees to pay for the alteration);
- because of the diminishing returns of each dollar spent on reliability improvements.
- by a customer's specific request (and agreement to pay for) a particular service level;
- when an external agency imposes a service level, or in some cases, an unrelated condition or restriction that manifests as a service level; such as a requirement to place all new lines underground, or a requirement to maintain clearances.

Consumer surveys over the past 4 years have indicated that consumer preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for major increases in service levels other than a reduction in the number of interruptions. This is the aspect of service on which Aurora intends to focus in the immediate future.

It is important to note that the new sections of the Electricity Act 1992 setting out the Safety Management System requirements may require a step increase in the level of public safety, and, therefore, a step increase in activities like inspections. Once the new clauses in the Act become operative Aurora will need to ensure that its program of inspections will meet the requirements, which may need to be reflected under the heading of public safety, above.

5 Network Development

5.1 Introduction

Capital expenditure on the Aurora network is driven by the following factors:

- growth in demand by existing consumers;
- connection of new consumers;
- replacement of aging equipment to meet safety and reliability standards;
- community requirement to convert overhead distribution to underground.

Aurora expects strong growth in electrical demand to continue in the areas served by the Frankton (4 to 5% growth per annum) and Cromwell (6 to 7% growth per annum) GXPs. There are a variety of forecasts that indicate growth could continue at these levels, or could fall. The projected capital budget reflects a continued growth scenario, so the predominant reason for capital expenditure is network extensions and upsizing demand capacity. Major capital works, such as zone substation upgrades, are sized to meet at least 20 years growth. However, each situation is individually studied taking into account local conditions (such as the ability to reticulate feeders, and the availability of land for new substations).

Modest growth, in the order of 1% to 2% per year, is expected in the area served by the Clyde GXP.

Minimal population growth is expected in Dunedin over the next 20 years. Overall growth in electrical demand is expected to average between 0% and 1%, but there will be localised areas where growth will exceed this. Capital expenditure in the Dunedin area will mainly be driven by the replacement of ageing assets, the conversion of overhead distribution to underground, and reliability improvements.

Aurora's projected capital expenditure is presented in Table 5.1 below:

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Customer connections	5,000	5,000	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Asset replacement and renewal	5,460	5,060	3,240	4,370	3,630	4,400	6,440	6,180	6,230	6,250
Reliability, safety environment	500	500	500	500	500	500	500	500	500	500
System growth	3,650	4,000	6,700	6,000	7,200	6,200	5,200	5,000	5,000	5,100
Asset relocations	400	400	400	400	400	400	400	400	400	400
Total	15,010	14,960	19,040	19,470	19,930	19,700	20,740	20,280	20,330	20,450

Table 5.1 – Capital Expenditure Forecast (\$000)

Capital expenditure categories are as defined in the Electricity Distribution (Information Disclosure) Requirements 2008, and are summarised as follows:

- customer connections: capital spent on new or upgraded connections;
- asset replacement and renewals: the replacement of obsolete or deteriorated assets;
- reliability, safety, and environment: works required for safety, reliability or environmental reasons;
- system growth: expenditure associated with a change in network demand;
- land purchases are excluded.

Specific projects currently under final investigation are described in Section 5 and include:

- Morven Ferry Road substation (5.11.2);
- Frankton zone substation (5.11.5).

Other potential mainly reliability-based projects are at the stage of preliminary investigation. These will be detailed in future AMPs.

Subject to final approval, it is expected that these projects will be commenced in the first five years of this Plan.

5.2 Distributed Generation Policy

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. Aurora encourages the connection of distributed generation to its network, and examines each proposal with regard to strategic network development. Aurora currently has in excess of 60MW of large embedded generation, albeit all pre-date the 1998 Electricity reforms.

Aurora has guidelines and application information for the connection of distributed generation published on its website at www.electricity.co.nz. These comply with the Electricity Governance (Connection of Distributed Generation) Regulations 2007. For the connection of larger capacity generation, technical matters are covered by the New Zealand Electricity Engineers Association's Guide for Connection of Generating Plant (October 2007), as cited in Aurora's guidelines

Aurora's Congestion Period Demand (CPD) pricing methodology financially rewards the operation of standby generation plant during network congestion periods. Aurora otherwise applies the pricing principals as scheduled in the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

As foreshadowed in the previous AMP, Aurora installed a generator at the future Cardrona substation site to defer subtransmission upgrades. The generator ran for approximately 100 hours over times of winter peak demand during the winter of 2008.

5.3 Non-Network Solutions

Demand Side Management (DSM) provides an alternative to investing in network assets. The primary mechanism for better utilisation of distribution assets is via Aurora's delivery pricing structure. In addition, a headwork's charge for new connections above 150kVA encourages designers of major installations to limit electrical demand by the introduction of load management and/or utilisation of alternative energy sources.

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, and results in peak demand being reduced by approximately 45MW (16%) across the Dunedin and Central networks, 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. During 2008, a number of consumers completed the alterations to their diesel generation plant to allow it to operate during congestion periods.

5.4 Planning Criteria

Planning decisions within the electrical distribution industry have historically been deterministic (such as the Guidelines for Security of Supply in New Zealand Electricity Networks June 2000), and risk over-investment.

In the past, the “n-1” criterion was applied almost universally at a subtransmission and zone substation level. Aurora uses the n-1 criteria as a screening tool to identify which parts of its subtransmission and zone substation network require the application of probabilistic analysis to determine economic network upgrades. Investment will occur when the net present value of the energy not supplied is greater than the investment.

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, or when the feeder has reached 85% of its thermal rating. On rural feeders, it is normally voltage drop that will determine the maximum capacity of a feeder, whereas it is thermal capacity that is normally the limit in urban areas.

5.5 Planning Process

Aurora’s planning unit is HV feeders, for which half-hourly load data is collected and analysed after each winter for all zone substations. This load data for the previous year, along with transformer MDI readings, is analysed to identify new investment expected over for the following six years. The development plan also includes projects to improve network reliability, and the renewal of aging assets where their reliability is assessed as being less than desirable. (Age alone is not a determinant for capital works.) Budgetary estimates for each project are produced.

There are usually multiple options to resolve most network capacity constraints. Options for relieving constraints include:

- Operational activities, in particular switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders, to avoid new investment.
- Influence consumers to alter their consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
- Construct distributed generation so that an adjacent asset’s performance is restored to a level below its trigger point. Distributed generation would be particularly useful where additional capacity could eventually be stranded, or where primary energy is going to waste; e.g., water being released from a dam that could be used in a hydro generator.
- Modify an asset so that the trigger point will move to a level that is not exceeded; e.g., by adding forced cooling. This is essentially a sub-set of the final approach described below, but will generally involve less expenditure. This approach is more suited to larger classes of assets such as 33/11kV transformers.
- Retrofitting high-technology devices that can exploit the features of existing assets. Examples include: using remotely operated Air Break Switches (ABS) to improve reliability, using advanced software to thermally re-rate heavily-loaded lines, or retrofitting core temperature sensors on large transformers.
- Install new assets, with greater capacity, which will increase the asset’s trigger point to a level that is not exceeded.

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. 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.

Aurora generally selects the option with the lowest life-cycle cost, by determining the NPV of the following costs associated with a project:

- initial construction;
- on-going maintenance;
- consumer outage costs associated with construction;
- cost of losses (presently valued at \$0.06 per kWh);
- on-going consumer outages.

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

5.6 Demand Forecasting Methodology

Demand predictions are undertaken annually, at HV feeder and zone substation level, and are based on past trends and known future developments. Factors that are taken into account include land zoning, population projections, and expected economic conditions.

Once every 5 to 10 years there is an extreme cold weather event; typically, a three-day snowfall that occurs during the week, and outside of the school holiday period. These events can add an additional 10% to the Dunedin peak demand. Aurora has determined that it is not economic to install additional assets to maintain normal supply security levels during these infrequent events, and load forecasts are based on “normal” weather conditions.

5.7 Project Prioritisation Methodology

In general, the priority for the completion of capital projects is determined in accordance with Table 5.2, below:

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.

Table 5.2 – Project Priority List

Projects described in section 5 are listed in Appendix A.

5.8 Equipment Ratings

Equipment ratings are assigned in accordance with Table 5.3, below:

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. See Table 5.4 for parameter allocation.
Switchgear	Manufacturer's assigned rating, no overload permitted.
Current transformers	120% of nominal rating unless rated for extended thermal range.
Cables	Some 33kV 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.

Table 5.3 – Assignment of Equipment Ratings

Parameter	Summer Day	Winter Night
Ambient temperature	30°C	10°C
Wind direction	60° to the conductor	60° to the conductor
Wind speed	1 m/s	1 m/s
Max conductor temperature	50°C	50°C
Latitude	45°	45°
Sun time	mid-day, 1 kW/m ²	None
Emissivity	0.5	0.5
Absorptivity	0.5	0.5

Table 5.4 – Parameters Used to Determine Overhead ACSR Conductor Ratings

5.9 Grid Exit Points

5.9.1 Demands and Growth Predictions

The history of peak demands (in MW) for the network areas associated with each GXP are shown in Table 5.5, below, and are equal to the demand on the GXP plus distributed generation.

Calendar Year		Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin
2002		17.1	19.9	37.4	133.0	65.9
2003		15.2	20.3	38.3	116.4	61.3
2004		15.6	21.5	41.4	126.0	67.0
2005		17.2	24.4	41.8	126.0	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		16.1	27.4	46.5	122.3	70.3
2009	<i>Predicted</i>	17.0	31.5	51.1	125.0	72.7
2010		17.2	33.7	53.4	126.3	73.4
2011		17.3	36.2	55.9	127.5	74.1
2012		17.5	38.7	58.5	128.8	74.9
2013		17.6	41.5	61.2	130.1	75.6
2014		17.7	44.5	64.0	131.4	76.4
2015		17.9	47.7	66.9	132.7	77.1
2016		18.0	51.1	70.0	134.0	77.9
2017		18.2	54.7	73.2	135.4	78.7
2018		18.3	58.6	76.6	136.7	79.5
2019		18.5	62.8	80.1	138.1	80.3
Past Growth Rate (Trend 2002 to 2008)		1.0%	7.1%	4.6%	1.0%	1.9%
2008 MW off take peak (excludes distributed generation)		3.4	24.1	45.5	105.4	70.3
Off take n-1 capacity (continuous) MVA		27	356	66	100	81
Off take n-1 capacity (24hr winter post contingency) MVA		27	35	88	112	81
Distributed generation (2008 MW at time of load peak)		13.5	3.3	1.0	16.9	n/a

Table 5.5 – GXP Area Peak Demands

Strong growth is predicted to continue in the Frankton and Cromwell GXP areas, with more modest growth in the Clyde and Dunedin GXP areas. The South Dunedin demand growth has been predicted to be 1.0%, as the apparent load growth of 1.9% was partly due to a 2MW load transfer from the Halfway Bush GXP in 2006.

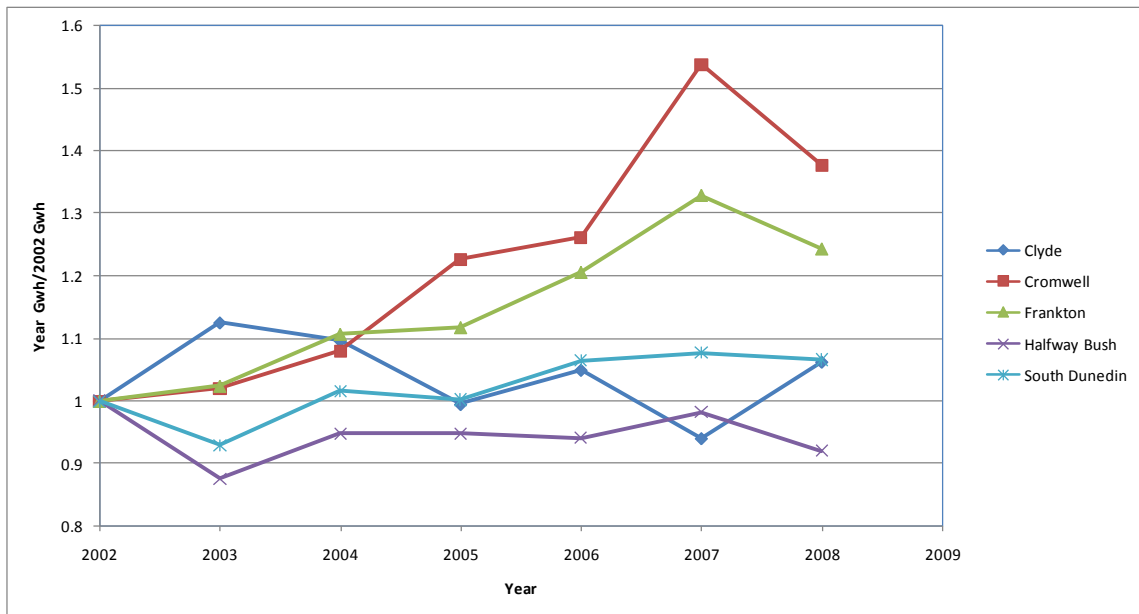


Figure 5.1 – Comparative Growth in GXP Energy

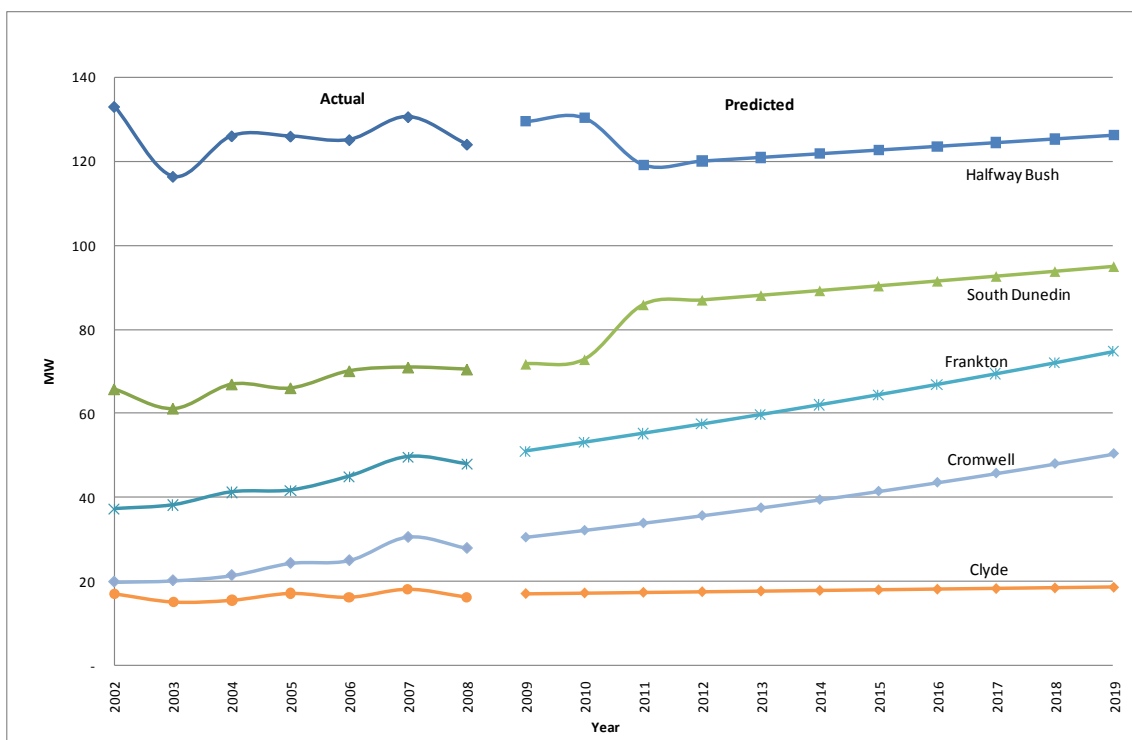


Figure 5.2 - GXP Area Peak Demands (Including Distributed Generation)

The reduction of demand in Dunedin and Clyde GXP areas in 2003 was due to the Government's energy savings campaign. The Dunedin 2002 peaks were due to an uncharacteristic three-day snowfall in May. The dip in 2008, compared to 2007, was due to the 2008 winter being milder than the previous year and a nationwide industry led energy savings campaign. The predicted dip in Halfway Bush's demand is due to the imminent closure of the Fisher & Paykel factory and a reduction in meat processing demand.

5.9.2 Frankton GXP

The Frankton GXP is supplied via 110kV lines from 220/110/33kV transformers at the Transpower Cromwell substation, as described in section 5.9.3, below.

The 2007 peak off-take on the Frankton GXP was 45.5 MW (excluding distributed generation).

In conjunction with the transformer upgrade in late 2007, Transpower has installed two additional 33kV circuit breakers for Aurora.

5.9.3 Cromwell GXP

The Cromwell GXP is “teed” off the Transpower 220kV lines that run between Twizel and Clyde. Two three-winding transformers at Cromwell supply both the 33kV breakers at the Cromwell GXP, and the 110kV Transpower supply to the Frankton GXP. The transformers are rated as 85/50/35 MVA for their 220kV, 110kV and 33kV windings respectively. The 2007 combined Cromwell and Frankton GXP demand was approximately 82MVA.

It was expected that the nominal 50 MVA rating on the 110 kV winding feeding Frankton would have been exceeded in the winter of 2009. The Transpower upgrade currently underway, consists of the paralleling the existing transformers on one circuit, and installing a new 220/110/33 kV, 150/150/50 MVA transformer on the other circuit. Completion is expected by April 2009.

5.9.4 Clyde GXP

The Clyde GXP has two 27 MVA transformers. The distributed generation on this GXP almost meets the total GXP demand. Should the distributed generation fail, the maximum demand on the GXP would be approximately 19 MVA, based on 2008 loadings. There is adequate GXP capacity at Clyde for the foreseeable future. Clyde GXP growth has been lower than for Frankton and Cromwell, and is not expected to accelerate during the planning period.

5.9.5 Halfway Bush GXP

The off-take peak at Halfway Bush exceeds the 112 MVA rating. This is not a major concern, as in the event of a failure of the Transpower 100MVA transformer, TrustPower would be asked to increase their 33kV generation during peak periods, and up to 5MW can be transferred to the South Dunedin GXP via the 6.6kV network. A contingency plan has been prepared for this situation.

Long term, it is planned to move the Neville Street substation load to the South Dunedin GXP when the Halfway Bush - Neville Street gas cables require replacement (see Sections 3.8.2 and 6.5.1). This will reduce the demand on HWB by approximately 13MVA.

5.9.6 South Dunedin GXP

The South Dunedin GXP presently has two 100 MVA transformers but they have been assigned an 81MVA limit by Transpower due to metering accuracy limitations. The present peak demand on South Dunedin is approximately 73 MVA but if the Neville St Substation load is transferred to South Dunedin the load would be very close to 84 MVA. The work required to eliminate the constraint is to change the metering CT ratio from 1200/1 to 2400/1 and recalibrate the meters, at an estimated cost of \$20,000.

5.10 Subtransmission

Potential subtransmission projects exceeding \$300,000 in cost are detailed in this section.

5.10.1 Frankton to Queenstown

Prior to the winter of 2008, the n-1 capacity of the 33kV subtransmission from the Frankton GXP to Queenstown was constrained by the 33kV cables into the Queenstown substation. This was resolved by upgrading the cables in 2008. No further works are anticipated within the planning period.

5.10.2 Cardrona Valley

Previous AMPs foreshadowed the installation of a 500 kW generator. This was completed before the winter of 2008 and ran for approximately 100 hours during times of peak loading. Preliminary planning for a 66 kV subtransmission upgrade is underway. The costs, timing are subject to further economic analysis to determine when this project is likely to proceed. The earliest this could occur would be by the winter of 2010 at a cost of \$ 4.3 million.

5.10.3 Wanaka to Hawea

Contact Energy proposes to install 16MW of hydro generation at Lake Hawea and has obtained resource consent. Subtransmission upgrade and new lines will be required between Wanaka and Hawea. It is proposed that the new line follows the route of the existing 11kV line in a 66kV over 11kV configuration. Contact's preliminary timetable requires confirmation. Resource and land owner consent will be required for this project.

5.10.4 Nevis Power Scheme

Pioneer Generation Limited is investigating a 40MW hydro generation station on the Nevis River and has enquired about options for connection to the Aurora network. Indicative costs have been given to Pioneer (in 2005) who also has the option of connecting to the nearby Transpower 110kV lines. This project is actively opposed by Fish and Game – no further work is planned until such planning issues have been addressed.

5.10.5 Maungatua Wind Farm

A windfarm has been proposed to be installed on the Maungatua Hills west of the Taieri Plain. If this occurred, it is likely that significant upgrades would be required to the subtransmission circuits that run from Waipori to the Halfway Bush GXP. No allowance has been made in this AMP as the scope of any such works has yet to be confirmed. However, external consulting advice is being obtained to confirm the likely nature of the required upgrade works.

5.10.6 Other Major Projects

Other major developments have been proposed confidentially by third parties. These, and possible consequential works, are not included within this document in order to protect third party commercial interests.

5.11 Zone Substations

5.11.1 Demand Projections

The historical and predicted demands for all zone substations are shown on Table 5.6. The following notes relate to the interpretation of this information.

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.

Predicted future demands are shown with a shaded background; when they exceed the firm capacity of the substation they act as a “flag” for closer study. Zone substations with a capacity of 3 MVA or less are not designed to n-1 security. Spare transformers are held that provide cover for several sites. The predictions are based on considering the [previous six years load demands with both exponential and linear predictions being considered in arriving at a judgement as to the future likely demands.

When the new Commonage, Morven Ferry (or its alternative option), and Jack’s Point substations are commissioned there will be a reduction in load of the existing Queenstown, Arrowtown and Frankton substations that are presently supplying the load. This is taken into account in future demand predictions.

Only existing distributed generation injection points and demand side management programmes are considered in preparing this forecast.

Appendix A provides a summary of indicative project timings.

Smith Street and South City

Approximately 1.5 MW of load was transferred from Smith St to South City in September 2005 after the substation peak loads were recorded. Future predictions take into account this transfer.

North City

The firm capacity has been restricted to 28 MVA due to the inability to deliver any more than this via the feeder breakers without further expenditure.

Queenstown, Commonage and Fernhill

These substations are allocated a firm capacity equal to their n-1 rating. Load can be transferred between them but the total load that can be supplied by the three substations is constrained by the 33kV subtransmission system. The loss of a transformer at Queenstown is not considered to be a problem due to adequate inter-ties to Frankton and Fernhill.

				Historical Demands MVA							Predictions			Predicted Demands Between Exp and Linear M									
Zone Substation	Transformer MVA	Firm Load MVA	n-1	2002	2003	2004	2005	2006	2007	2008	Previous Growth (Exp) %/yr	Exponential Growth %/yr	Linear Growth MVA/yr	2009	2010	2011	2012	2013	2014	2015	2016	2017	
Alexandra	7.5/15+7.5/15	15	15	11.1	10.0	10.4	10.8	10.9	12.4	11.4	2.00%	2.0%	0.22	11.9	12.1	12.3	12.6	12.8	13.0	13.3	13.5	13.8	
Anderson's Bay	15 + 15	18	18	15.5	13.5	15.3	14.6	14.9	16.6	15.7	1.52%	1.0%	0.23	16.0	16.2	16.4	16.6	16.8	17.0	17.2	17.4	17.6	
Arrowtown	5 + 5	7.5	6	5.6	6.3	6.3	6.4	7.2	7.7	7.3	4.82%	4.8%	0.31	8.0	8.3	8.7	9.0	9.4	9.8	10.2	10.6	11.0	
Berwick	3	3.6	0	1.2	1.2	1.1	1.1	1.1	1.2	1.2	0.13%	0.1%	0.00	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	
Clyde/Earnsclough	4 +2	4.8	4	4.7	4.1	3.6	3.6	3.7	4.0	4.1	-1.55%	1.0%	0.04	4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	
Coronet Peak	5	6	0	0	0	3.0	4.4	3.6	3.6	4.5	6.29%	1.0%	0.20	4.4	4.5	4.6	4.7	4.9	5.0	5.1	5.2	5.4	
Corstorphine	12/24 + 12/24	23	23	13.5	12.2	13.1	12.5	12.8	13.8	12.5	-0.03%	0.3%	0.00	12.9	12.9	13.0	13.0	13.0	13.0	13.0	13.1	13.1	
Cromwell	5/10 + 7.5	9.0	9.0	6	6.6	7.1	6.8	7.9	9.2	9.2	7.55%	5.0%	0.55	9.7	10.3	10.8	11.3	11.9	12.5	13.0	13.6	14.3	
Dalefield	3	3.6	0	3.0	3.0	1.4	1.9	1.8	2.3	2.1	10.43%	7.0%	0.17	2.4	2.6	2.8	3.0	3.2	3.4	3.6	3.8	4.0	
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
East Taieri	12/24 + 12/24	See Text	18.5	14.7	13.6	14.2	14.9	15.7	15.7	15.5	1.99%	2.0%	0.29	16.1	16.4	16.7	17.0	17.3	17.6	18.0	18.3	18.6	
Ettrick	3	3.6	0	2.0	2.0	1.8	2.0	1.5	2.0	1.8	-1.88%	0.5%	0.00	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	
Frankton	7.5/15 + 7.5/10	12	10	7.9	7.8	8.0	9.0	10.4	12.0	13.2	9.96%	7.0%	0.60	12.9	13.7	14.4	15.3	16.1	17.0	16.0	16.9	17.9	
Fernhill	7.5/10+7.5/10	10	10	4.8	5.2	5.2	5.4	5.6	6.1	6.2	4.16%	4.2%	0.22	6.4	6.7	6.9	7.2	7.4	7.7	8.0	8.3	8.6	
Green Island	15 + 15	18	18	12.5	12.9	13.6	13.8	14.0	14.2	13.8	1.84%	1.8%	0.24	14.5	14.8	15.0	15.3	15.6	15.8	16.1	16.4	16.6	
Halfway Bush	15 + 15	18	18	14.1	12.2	12.3	13.1	13.6	14.2	13.8	1.24%	1.0%	0.16	14.0	14.1	14.3	14.4	14.6	14.7	14.9	15.0	15.2	
Kaikorai Val.	12/24 + 12/24	23	22	9.0	9.0	10.0	11.9	10.3	10.4	9.9	2.15%	2.0%	0.20	10.9	11.1	11.3	11.5	11.7	12.0	12.2	12.4	12.6	
Maungawera/Hawea	3	3.6	0	2.3	1.9	2.2	2.3	2.5	3.2	2.1	3.64%	5.0%	0.10	2.6	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	
Mosgiel	10 + 10	14	12	12.0	11.0	11.6	11.8	12.2	12.0	12.0	0.82%	0.8%	0.05	12.2	8.2	8.3	8.4	8.4	8.5	8.5	8.6	8.6	
Neville St	15 + 15	18	18	13.6	13.0	13.6	13.9	14.4	14.9	13.3	0.95%	1.0%	0.13	14.3	14.5	14.6	14.7	14.9	15.0	15.2	15.3	15.4	
North City	14/28 +14/28	28	28	21.1	21.1	20.4	19.8	20.2	20.7	20.3	-0.59%	0.5%	0.10	20.2	20.3	20.4	20.5	20.6	20.7	20.8	21.0	21.1	
North East Val.	9/18 +12/18	23.9	18	11.4	10.2	11.4	10.8	10.8	11.0	10.9	-0.13%	0.5%	0.05	10.9	11.0	11.0	11.1	11.1	11.2	11.2	11.3	11.4	
Omakau	3	3.6	0	1.54	1.7	1.5	1.6	1.6	1.8	1.8	2.34%	2.3%	0.04	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.1	
Outram	3 + 3	5.6	3.6	2.5	2.5	2.6	2.6	2.9	2.8	2.7	2.21%	2.0%	0.06	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.3	3.4	
Port Chalmers	7.5 +7.5	10	9	7.5	7.6	7.9	8.1	7.9	8.3	7.5	0.67%	1.0%	0.05	8.1	8.1	8.2	8.3	8.3	8.4	8.5	8.5	8.6	
Queensberry	3	3.3	0	0.6	0.8	1.4	1.6	1.9	1.7	1.8	19.73%	5.3%	0.21	2.3	2.4	2.6	2.8	3.0	3.1	3.3	3.5	3.7	
Queenstown	10/20 +10/20	22	20	18.3	18.0	20.4	18.3	20.2	22.8	22.1	3.74%	3.7%	0.40	14.9	15.4	15.8	16.3	16.9	17.4	17.9	18.5	19.0	
Remarkables	1	1.2	0	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.10%	0.0%	0.00	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Roxburgh	1.5 +1.5	3.6	1.8	2.9	1.9	1.7	2.3	2.5	2.5	2.2	0.52%	0.5%	0.01	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	
Smith St	15 + 15	18	18	19.0	16.0	18.1	18.1	16.5	16.9	16.1	-1.71%	1.0%	0.20	16.5	16.7	16.9	17.1	17.2	17.4	17.6	17.8	18.0	
South City	9/18 +9/18	18	18	13.0	11.8	13.6	14.3	15.4	15.7	15.3	4.30%	1.0%	0.20	16.1	16.3	16.5	16.7	16.9	17.0	17.2	17.4	17.6	
St Kilda	12/24 + 12/24	29	23	14.7	14.7	15.1	15.2	15.4	16.3	15.6	1.45%	1.4%	0.22	16.2	16.4	16.6	16.9	17.1	17.3	17.6	17.8	18.0	
Wanaka	12/24 +12/24	24	24	11.4	11.5	13.6	14.6	15.1	18.6	18.7	9.51%	7.5%	1.20	20.3	19.6	21.0	22.4	23.8	25.4	27.0	20.7	22.1	
Ward St	15 + 15	18	18	11.0	10.4	10.9	10.6	11.6	11.3	11.4	1.20%	1.2%	0.13	11.6	11.7	11.8	12.0	12.1	12.2	12.4	12.5	12.7	
Willowbank	15 + 15	18	18	12.2	12.1	13.7	13.7	12.8	12.7	12.5	0.33%	0.5%	0.04	13.0	13.0	13.1	13.1	13.2	13.2	13.3	13.3	13.4	
Commonage	7.5/15+7.5/15	15	15									3.7%	0.24	8.0	8.3	8.5	8.8	9.1	9.4	9.7	10.0	10.3	
Cardrona		5										7.5%	0.18		2.5	2.7	2.9	3.0	3.2	3.3	3.5	3.6	
Jacks Point *	7.5/10	10	0									8.0%	0.20							2.0	2.2	2.4	
Wanaka 2	12/24 + 12/24	23	23									6.0%	0.48								8.0	8.5	
MG + ET (Merged 1/2hr data)		30.8	30.8		24.39	25.05	25.98	27.25	26.46	26.68	2.50%	3%	0.6	28.4	25.1	25.7	26.4	27.0	27.7	28.3	29.0	29.7	

Table 5.6 – Zone Substation Historical and Predicted Demands

5.11.2 **Morven Ferry Substation/Arrowtown Substation Upgrade**

A new substation was proposed near the junction of Morven Ferry Road and SH6, to relieve the loading on the Arrowtown substation and to support the voltage in the Gibbston valley. An alternative is to increase the capacity of the Arrowtown zone substation. This is still believed to be the cost-effective option so this proposal is not shown in Table 5.6 above. Further investigations are required to confirm that increasing the capacity of the Arrowtown substation is the better option.

The estimated project cost is \$2,000,000 with the earliest completion date being before the winter of 2012.

5.11.3 **Mosgiel Substation**

It is necessary to consider East Taieri and Mosgiel together when allocating a firm load to these substations. The firm load allocation is on the basis of a single contingent event with the loss of the Waipori generation counted as one event. With the present network configuration the combined firm load allocated is 30.8 MW. The closure of the Fisher and Paykel factory is expected to reduce the load by 4 MVA in 2009 resulting in no need to augment supply during the planning period.

Subject to growth at the Cromwell substation, it is proposed that new transformers be installed at the East Taieri substation in 2010/2012 and the existing transformers be transferred to the Cromwell substation. This would give the Cromwell substation the additional capacity predicted to be required by then and would remove the voltage constraint at East Taieri.

This is estimated to cost \$2.4 million.

The replacement of the 11kV switchgear at Mosgiel is underway.

5.11.4 **Tarras Substation**

The Queensberry substation had a 2006 peak load of 1.9 MVA (2008 peak of 1.8 MVA) and the area is still experiencing strong growth mainly due to irrigation load. There is no spare 66/11kV transformer available in the event of the Queensberry unit failing. The 2006 plan recommended that a new substation be established in Maori Point road to support the Queensberry substation and provide an alternative supply should the Queensberry transformer fail.

During a review process it was decided to investigate the purchase of a mobile substation that could be used to replace the Queensberry transformer in the event of a failure and can also be used to as a replacement for other Aurora transformers. This project has been authorised and is underway at a cost of \$1.4 million.

The provision of a new substation at Tarras is therefore not contemplated within the planning period and therefore will not be mentioned in future AMPs.

5.11.5 **Frankton Substation**

Frankton substation has a 7.5/15 MVA and a 7.5/10 MVA transformer. The substation exceeded its firm load in 2008 ahead of the prediction to reach this in 2010.

A project to upgrade the Frankton substation to a more secure transformer-feeder configuration was completed in 2007/08. This project involved the installation of a new 33kV cable from the Transpower GXP to the Frankton substation and the installation of inter-tripping. The project utilises the two additional 33kV breakers provided by Transpower as detailed above.

There are no viable alternatives such as relocation to augmenting the existing substation.

The 11kV switchgear at Frankton is old and cannot be remotely controlled. There is insufficient space to easily accommodate additional 11kV feeders. Additional feeders will be required to supply new load. The two bus sections are connected by cable which will soon have insufficient capacity. It is proposed that new indoor 11kV switchgear be installed in a new building. This building will be designed and located to facilitate the eventual moving of the substation. The switchgear upgrade is estimated to cost \$1.0 million.

Whilst approximately 1 MVA of load will eventually be transferred to an embedded network owner (Aurora expected this to have already taken place in 2007). Augmentation of the Frankton substation will be required by 2011. This could be initially provided by a new substation at Jack's Point in 2011 (see section 5.11.9). Further studies as to what is the best augmentation solution are planned in 2009-2010.

5.11.6 Queenstown Substation

The construction of the 7.5/15 MVA Commonage substation defers any augmentation of Queenstown to beyond the planning period.

5.11.7 Cromwell Substation

The Cromwell substation exceeded its firm capacity in the winters of 2007 and 2008. A number of options are available. The preferred option is to ensure the mobile substation is available which would allow load to increase up to 12.5 MVA so delaying the need to replace the existing transformer. Preliminary investigations indicate that the possibility of moving a transformer from East Taieri in 2011 to increase the capacity of this substation is the best solution that maximises the use of existing assets at a cost of \$400,000. Further work is required to confirm this.

5.11.8 Commonage Substation

This project will be complete before the winter of 2009.

5.11.9 Jack's Point Substation

Significant developments (2,700 lots) are under way in the Jack's Point area, which is off the Frankton to Kingston Road approximately 5 km from Frankton. This development would be initially supplied from Frankton feeder 703 up to a load of approximately 2 MVA. When this load limit is reached, it is intended to install a 33/11kV substation supplied from the 33 kV line to Wye Creek.

The substation will be designed to eventually accommodate two 5/10MVA transformers. A site has been chosen and a 33kV cable has been installed to the site. Timing depends on the uptake of subdivision lots but is anticipated to be by 2011 at the earliest. The site is to be designated as per RMA requirements in the 2009-2010 year. The total project cost estimate is \$1,300,000.

This option would put the zone substation close to a point of new load and is considered to be financially better than running more feeders from the Frankton zone substation. However if load growth is low then the upgrading of the Frankton zone substation would be the better option in the interim.

5.12 HV Feeders

A feeder's rating is the minimum of its circuit breaker rating, outgoing cable rating, or 1.2 x the CT nominal rating. Feeders are not permitted to exceed their rating. Database report "Feeder Load Prediction" predicts the load on all HV feeders and lists feeders expected to exceed 85% of their rating during the planning period.

In the event of a fault, the ability to off-load a feeder to adjacent feeders is calculated by the "Feeder Loading" database. When it becomes impossible to completely off-load a feeder, analysis is carried out to assess if the investment to eliminate the off-loading constraint is economic.

Rural feeder upgrades are generally driven by consumer low voltage complaints. The maximum load most rural feeders can carry is normally constrained by voltage drop. The maximum tolerable feeder volt drop is 5% when consumers at the end of the feeder are supplied by LV distribution. When customers near the end of a feeder have their own dedicated transformer, which is generally the case for rural feeders, then a higher HV volt drop can be tolerated before the consumers voltage goes out of the allowable $\pm 6\%$ range. Voltage monitoring equipment that telemeters voltage from a consumer's installation has been installed on some "at risk" feeders.

Remedial action that could be required within the planning period to eliminate feeder loading constraints has been identified. An allowance of \$1.06 million for work on nine feeders has been made within the planning period.

5.13 Distribution Substations

Distribution substation projects are not itemised in the Asset Management Plan as they are usually driven by new customer connections and an appropriate response is made at the time.

5.13.1 Distribution Substation Utilisation

The loading of all distribution transformers greater than 200kVA (which represents 78% of installed transformer capacity) is monitored by Maximum Demand Indicators (MDIs). The MDIs in "at risk" substations are read at least annually and for other substations the interval is longer. Overloading of smaller substations is normally brought to attention by LV fuses failing or voltage complaints. Utilisation data is shown in Table 5.7 and is for all transformers connected to the Aurora network including those not owned by Aurora.

Year	2004	2005	2006	2007	2008
Utilisation	32.5%	34.2%	33.6%	33.2%	33.7%

Table 5.7 – Distribution Transformer Utilisation

Overall, utilisation is above the 30% ODV optimisation threshold.

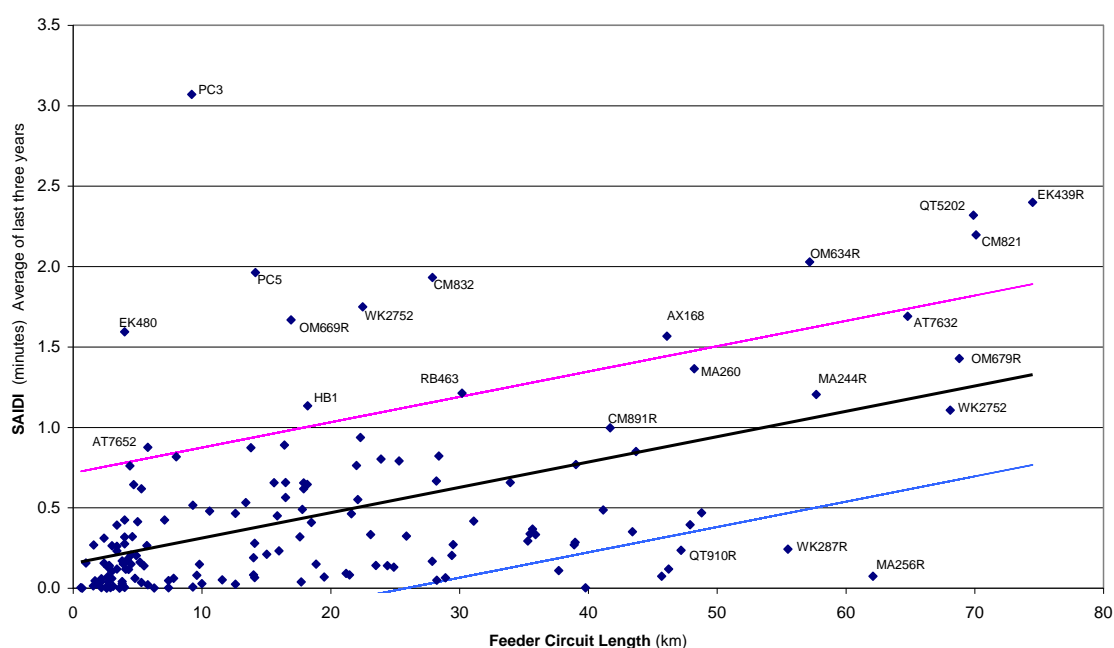


Figure 5.4 – HV Feeder Customer Outage Minutes by HV Feeder (2006-2008)

5.15 Overhead to Underground Conversion Projects

Aurora has a policy of assisting local authorities place overhead lines underground.

The projected available funding envelope by local authority area is detailed in Table 5.8 below.

Authority	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
DCC	1,640	1,660	1,680	1,700	1,720	1,740	1,760	1,780	1,810	1,830
CODC	290	300	310	320	330	340	350	360	370	380
QLDC	480	490	500	510	530	550	570	590	600	610
Total	2,410	2,450	2,490	2,530	2,580	2,630	2,680	2,730	2,780	2,820

Table 5.8 – Overhead to Underground Conversion Budget (\$000)

Expenditure in the CODC and QLDC areas is subject to the respective Authorities contributing on a 50:50 basis. If this does not occur then the undergrounding budgets will not be spent.

5.16 New Customer Connections

New customer expenditure includes the cost of extensions to the Aurora network to facilitate the connection of customers to the network; that is, subdivisions and individual connections. Customers make a contribution toward the cost of this work in accordance with the Aurora capital investment policy.

The expenditure in these categories is entirely customer driven and subject to regional economic activity. The budgeted annual expenditure is presented in Table 5.1 above. This forecast is shown as a constant \$8.2 million per year after a two year drop off due to reduced economic activity currently being experienced in the Central region.

6 Lifecycle Asset Management Planning for Maintenance and Renewal

6.1 Maintenance Planning Criteria and Assumptions

The prime asset management considerations are customer service (particularly reliability of supply), longevity, and economic efficiency, which act against the background of safety and environmental responsibility. Aurora network maintenance is conducted in line with the risk management policy described in Section 7.1 and is reflective of customer, community, and legislative requirements, in addition to fulfilling Aurora's business objectives.

Maintenance expenditure is now split into three categories, as per the Electricity Distribution (Information Disclosure) Requirements 2008. These are summarised below:

- Routine and Preventative Maintenance: Programmed maintenance, including post fault inspections and repairs.
- Refurbishment and Renewal Maintenance: Replacement or refurbishment of components of an asset class, as described in the ODV Handbook.
- Fault and Emergency Maintenance: response to unplanned events.

Table 6.1, below, summarises the forecast maintenance expenditure in the above categories.

Maintenance Expenditure \$,000)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Fault and Emergency	3,358	3,450	3,545	3,642	3,742	3,845	3,951	4,060	4,171	4,286
Refurbishment & Renewal	956	982	1,009	1,037	1,066	1,095	1,125	1,156	1,188	1,220
Routine and preventative	3,335	3,426	3,521	3,617	3,717	3,819	3,924	4,032	4,143	4,257
Total	7,648	7,858	8,075	8,297	8,525	8,759	9,000	9,248	9,502	9,763

Table 6.1 – Routine and Preventative Maintenance Costs Summary, by Disclosure Requirements Category

Third party damage is excluded from the above table, as this is unplanned work not initiated by equipment condition.

The proportion of overhead to undergrounding works that would be expensed, such as removal of overhead lines, is also excluded from the above but it is included in the capital forecasts in Table 5.8.

Effective maintenance management involves balancing the cost of maintenance against the cost of replacement, after including the consequences of failure in both scenarios. Age-based maintenance and renewal, while conservative in engineering terms, tends to lead to unnecessarily high maintenance (replacement) costs. Aurora's maintenance strategy is based on careful monitoring of asset condition to balance the risks. Aurora continues to refine its maintenance management systems by reviewing practices and policies regularly.

Objective defect criteria are defined for all assets, and all defects reported are recorded in a defects register until the required remedial work is undertaken. Once a defect has been identified, remedial work is programmed before the risk and consequences of failure become unacceptable. The criteria primarily ensure that detected defects will not lead to equipment failure prior to the next inspection, or before work can be programmed to rectify the defect. Apart from some critical smaller items, assets are not renewed based on age or other generic criteria; they are kept in service until such time as their continued refurbishment is uneconomic, or until they pose a safety or reliability risk.

6.2 Routine and Preventative Inspection and Maintenance

Around 44% of Aurora's maintenance expenditure is for periodic inspections, servicing and tests, and associated maintenance to ensure that defects or emerging risks are identified and mitigated. Servicing can also involve minor component replacements (for example - seals, bushings etc), but does not involve any significant repairs.

DELTA has developed routine procedures for this type of work, specific to each asset type, which 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).

Subtransmission lines undergo detailed inspection every five years and are patrolled annually in the interval.

For circuit breakers, 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, costing in the order of a few hundred dollars per breaker, to infrequent major overhauls, costing up to several thousand dollars. 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 (for example) chemical analysis of transformer oil, and use of thermographic cameras to identify "hot spots".

Objective defect criteria are defined for all items, and 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 still 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).

6.2.1 Subtransmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and Mass Impregnated Non-Draining (MIND) and XLPE types. Pressure alarms are installed on the former two, and these are tested at six-monthly intervals, and the outer sheath electrical integrity on most cables is tested annually. Occasionally, leaks develop in these cables, usually at joints or where the cables have been stressed on installation. Faults are expensive to repair, being very labour intensive. MIND cables are virtually maintenance free but faults occasionally occur due to insulation migration on hill sections, or if they have been damaged by third parties (for example - road openings etc).

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.

Overhead Lines

Annual drive-by patrols are carried out on the overhead 66kV and 33kV lines to provide a visual check on such aspects as tree growth, leaning poles, or broken insulators, etc. All overhead lines and poles are closely inspected on a regular basis, and condition assessments made and recorded for maintenance planning.

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

Protection Pilots

Most of the pilot circuits are underground cables, generally run with 33kV cables. They are tested biannually for continuity, insulation resistance, and attenuation.

6.2.2 Zone Substations

33kV Transformers and Tapchangers

The transformers are relatively trouble free, apart from occasional oil leaks from bushings or radiators. The exception to this was in late 2006 when one transformer required repairs following ingress of water. All transformers have their insulating oil tested annually for acid level, breakdown resistance, and moisture content. DGA testing is completed on a 2-year cycle.

Buchholz relay operation tests are conducted, along with tests of winding and oil temperature alarms, from source. These occur at 4-year intervals, and are carried out in conjunction with associated circuit breaker maintenance.

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

Tapchangers are routinely overhauled after a set number of operations, dependent on type. Routine scheduled work on transformers and tapchangers is undertaken on a contract basis.

Buildings and Grounds

A 10-year building maintenance plan details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services, and the interior. 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.

Circuit Breakers and Isolators

Oil circuit breakers are given a routine minor service at 2.5-year intervals, and a major overhaul every 5 years, or after operation under severe fault conditions. The timeframe between servicing is currently being reviewed with the intention of implementing a condition based programme. Painting of outdoor circuit breakers is undertaken on a rolling basis with, major repaints at 10-year intervals.

Isolators are checked for operation and condition in conjunction with the 2.5 year routine maintenance check for the circuit breakers.

Ripple Injection Plant

Routine maintenance of ripple injection plant in the Dunedin network area consists mainly of contactor checks, and the dressing or replacement of contacts. The solid state coupling cells are virtually maintenance free. The 33kV injection equipment in the Central network area is solid state, relatively new, and has minimal maintenance requirements.

Miscellaneous

All batteries are, at present, in reasonably good condition, with larger units monitored by discharge tests.

Above ground earth connections, for all equipment, are inspected and maintained at 5-yearly intervals. The main earth grid connection resistances to above ground attachment points have been measured to a common datum at each substation, and these measurements are checked at 5-yearly intervals for changes in value. Sample underground connections to the main earth grid are also checked at 5-yearly intervals for physical deterioration.

At 12-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. All alarms are tested at 2.5 yearly-intervals, from the local alarm panel and from source, and confirmed at System Control on the SCADA screen, and by printout. The work is carried out in conjunction with minor circuit breaker servicing work.

Portable fire extinguishers and the CO₂ flood systems in load control coupling cell cubicles are inspected annually. Pressure cylinders are tested at regulated intervals dependent upon age. Inspection is carried out internally, with repairs and pressure testing conducted by external contract.

6.2.3 HV and LV Lines and Cables

At present, lines are inspected approximately every three years, and the procedures in the Electricity (Hazards from Trees) Regulations 2003 are followed. A précis of the regulations is published on Aurora's website.

HV and LV Lines

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.

HV and LV Cables

Apart from a five-yearly inspection of underground 400 Amp LV link boxes in the Dunedin central business district, no routine inspections of cables or associated equipment are made.

Earths

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, and tested at six-yearly intervals.

6.2.4 Distribution Substations

Substations

Ground-mounted substations that have HV circuit breaker equipment installed, have their tripping batteries checked three monthly and, where applicable, alarms are tested six monthly. All ground mounted substations are inspected annually.

Pole substations greater than 100kVA are also inspected annually in conjunction with the scheduled MDI reading round. Smaller sized pole substations are inspected as required.

Buildings and Grounds

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

Switchgear

Ring-main switchgear is relatively maintenance free, and checks on oil levels and general condition are included in the annual substation inspection round. The HV oil circuit breakers installed in some substations are overhauled at five-year intervals, or following operation for over-current fault.

6.2.5 System Control

SCADA

At 12-monthly intervals, all transmit and receive levels on the communications panels are checked, recorded, and adjusted if necessary, and power supplies are checked at the master station and all remote terminals.

UHF and VHF Systems

At 12-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 checked on a monthly basis, from a common point.

Miscellaneous

All ladders, portable earthing equipment, and safety gear used in zone substations are inspected or tested at six-monthly intervals.

6.2.6 Expenditure Projections

It is expected that the routine and preventative maintenance costs to meet agreed service targets over the next 10 years will be generally in line with the figures shown in Table 6.2, below:

Financial Year	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Subtransmission	351	361	371	381	392	402	413	425	436	448
Zone substations	857	880	905	930	955	981	1,008	1,036	1,065	1,094
System control	152	156	160	165	169	174	178	183	188	194
HV and LV	1,634	1,679	1,725	1,773	1,882	1,872	1,923	1,976	2,030	2,086
Distribution substations	341	350	360	369	380	390	401	412	423	435
Total	3,335	3,426	3,521	3,617	3,717	3,819	3,924	4,032	4,143	4,257

Table 6.2 – Routine and Preventative Maintenance Costs Summary, by Asset Category

6.3 Asset Renewal and Refurbishment Policies

6.3.1 Planned Renewal and Refurbishment

Around 13% of maintenance expenditure is for planned renewals, and refurbishment of unserviceable assets. About half of this involves asset renewal, or refurbishment programmes, to a class or model of asset or component based on evidence of a "type failure" or design weakness.

These programmes of work are identified and planned before the beginning of each financial year. The remainder comprises a large number of, typically minor, component refurbishments; for example, individual insulators, many of which arise out of specific defects found within the year.

6.3.2 Fault Refurbishment

Fault refurbishments are carried out directly following an equipment failure, in order to restore service, and account for around 44% of maintenance expenditure. This work may, or may not, involve permanent refurbishment of the faulted equipment, as the objective is to restore service as quickly as possible by the most economical method. If the 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 refurbished later, or disposed of if refurbishment cannot be justified.

6.3.3 Overhead Line Repairs and Refurbishment

Future maintenance workloads are projected using an analytical model. The assessed condition of each major component of each line is coded against condition criteria which are used to set maintenance priorities.

6.3.4 Circuit Breaker Renewal

Modelling has also been undertaken for programming circuit breaker renewals, 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.

Servicing expenditure for circuit breakers is also produced by the same model. 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.

6.3.5 Power Transformer and Distribution Transformer Renewals and Refurbishment

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.

6.4 Maintenance and Refurbishment Programmes

6.4.1 Subtransmission

Cables

The 33kV underground cables do not have a planned refurbishment programme. Replacement will occur when the cost of repairs become uneconomic. Leaks occasionally develop on the gas and oil filled cables, usually at joints or where the cables have been stressed on installation. Faults refurbishment is expensive, being very labour intensive. The MIND cables are virtually maintenance free but faults occasionally occur due to insulation migration on hill sections or if they have been damaged by third parties (for example - road openings, etc).

Overhead Lines

No 33kV overhead lines have been identified as requiring renewal or refurbishment. Some minor works, required to straighten insulators on the 66 kV lines from Cromwell to Wanaka, have been completed.

Protection Pilots

No protection pilots have been identified as requiring renewal or refurbishment.

6.4.2 Zone Substations

33kV Transformers and Tapchangers

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

Tapchangers are refurbished at intervals based on a predetermined number of operations. The usual work required is the dressing or replacement of contacts, and filtering of oil, but springs and driving mechanisms are also checked.

All transformers have had their insulating oil refurbished in the last few years, and all transformers now have less than 0.1 mg KOH/g acid level, good breakdown resistance, and low moisture content.

Buildings and Grounds

As part of the works identified in the ten year building maintenance plan, a number of buildings will have exterior paint work carried out within the planning period.

Circuit Breakers, Isolators and Structures

Fourteen 33kV circuit breakers are now over 40 years old, and some will require renewal within the next 10 years.

One hundred and forty two 6.6 and 11kV circuit breakers are now over 40 years old, and some will require renewal within the next 10 years.

Ripple Injection Plant

As part of the routine contactor checks in Dunedin, contacts will be renewed. Most motor-generator sets have had their bearings renewed in recent years, and no further renewals are considered necessary within 4 years.

At present no 33kV injection equipment in the Central network area has been identified as requiring renewal or refurbishment other than the Cromwell upgrades that are underway in association with the Transpower GXP upgrade.

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.

Miscellaneous

All batteries are at present in reasonably good condition, with renewal of smaller units initiated by age, and larger units by discharge tests.

6.4.3 HV and LV Lines and Cables

HV and LV Lines

Hardwood poles are presently 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 5 kilometres of HV conductor and cross-arm renewal is programmed each year, in both the Dunedin and Central areas, and it is expected that this level of renewal will be sufficient for the next 10 years.

Approximately 2 to 5 kilometres of LV conductor and cross-arm renewal is programmed each year, depending on condition assessments. 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.

HV and LV Cables

Renewal work has been carried out, over recent years, on the LV distribution system in the Queenstown and Alexandra CBDs, where many obsolete link pillars have been renewed with modern units that provide a safer and more flexible system. This work has now been extended to the Wanaka and Cromwell areas.

Earths

Earths identified during routine inspection as requiring attention will be refurbished as required.

6.4.4 Distribution Substations

Transformers

In the Central Otago area, some 5 (out of an original population in excess of 40), pedestal-mounted transformers are left to be renewed. They have been identified as being a latent safety concern, and are planned to be renewed with ground-mounted substations within the year.

Substations

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

Buildings and Grounds

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

Switchgear

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 plan.

6.4.5 System Control

SCADA

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.

UHF and VHF Systems

No UHF or VHF systems have been identified as requiring renewal or refurbishment.

Miscellaneous

Ladders, earthing equipment, and safety gear at zone substations identified as requiring refurbishment during the six monthly inspections will be refurbished as required.

6.4.6 Expenditure Projections

It is expected that the refurbishment and renewal costs, (excluding fault repairs and third party damage), to meet agreed service targets over the next 10 years, will be generally in line with the figures shown in Table 6.3, below:

Financial Year	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
Subtransmission	54	55	57	58	60	62	63	65	67	69
Zone substations										
System control										
HV and LV	686	704	724	744	764	785	807	829	852	875
Distribution substations	217	223	229	235	241	248	255	262	269	277
Total	956	982	1,009	1,037	1,066	1,095	1,125	1,156	1,188	1,220

Table 6.3 – Refurbishment and Renewals Costs Summary by Asset Category (\$000)

Renewals within zone substations are usually major items; for example, 11 kV switchgear replacements, and as such are part of the capital renewals schedule.

6.5 Capital Replacement Projects

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; ie, a cost-benefit analysis. Potential projects exceeding \$300,000 in cost are detailed in this section.

6.5.1 33kV Gas Cables

Five Dunedin zone substations are supplied by gas insulated 33kV cables, as detailed in Table 6.4 below. These cables have been prone to gas leaks, and the failure rate has increased significantly since mid 2003. For six months in 2004-05, the failure rate reached 20 failures per 100 km per year, which was unacceptably high. Since then the failure rate has reduced and remains low. No robust explanation for this random behaviour has been found.

Cable	Year Installed	Route Length (km)		Notes
		Actual	Optimised	
HWB–Neville Street	1961	6.82	1.7	Has a tie to Ward Street
HWB–Ward Street	1967	4.21		Has a tie to Neville Street
HWB–Willowbank	1963	3.95		
HWB–Smith Street	1959	3.2		
South Dn–Andersons Bay	1961	2.7		

Table 6.4 – Schedule of 33kV Gas Cables

The direct cost of repairing gas cable leaks in 2003/04 was \$156,000, in 2004/05 was \$225,000, in 2005/06 was \$105,000, in 2006/07 was \$38,000 and in 2007/08 was \$32,000. This, in itself, is not grounds for cable replacement; but initial analysis after taking the cost of non-supply into consideration, indicates that replacement may become economic if the repair frequency increased consistently back to 2004/05 levels.

In 2001, consultants prepared a report on options for the replacement of the Neville Street gas cables, which concluded that the failure rate to 2001 did not justify replacement as the Ward Street to Neville Street tie cable provides additional security. Partial discharge tests indicated that the tie cable is in good condition. In this case, had there not been a back up cable available, the replacement of the Neville Street cables would have been authorised.

A preliminary plan has been developed, which suggests that the existing transformer-feeder configuration adopted in Dunedin will be optimal for the future. Upgrading would then be driven by risk of outages, and the failure cost. Further analysis is required to confirm whether this plan is the most appropriate.

6.5.2 Ward Street Substation Upgrade

The transformers and 6.6kV switchgear at Ward Street were installed in 1938 (70 years old). Additional switchgear was added in 1943 and 1951. The entire substation is to be rebuilt during the summer/autumn of 2009/10. There were no suitable sites to relocate this substation, hence the decision to re-build it at the existing site. The project cost estimate is \$4.36 million.

6.5.3 Zone Substation 6.6/11kV Switchgear Replacement

The following zone substation 6.6/11kV switchgear is older than their ODV life (40 years). This, in itself, is not a reason for replacement – condition and perceived reliability are the relevant factors considered. The switchgear tentatively scheduled for replacement is listed in Table 6.5, below.

Substation	Manufacture Year	Status	Number CBs	Replacement Year*	Cost (\$000)
Ward Street	1938	Underway	14	2010/11	Note 1
Roxburgh	1950	Planned	1	2011/12	30
Remarkables	1950	Underway	1	2009/10	40
Frankton	1950	Planned	8	2010/11	Note 2
Neville Street	1953	Monitor	14		
Mosgiel	1954	Underway	10	2008/09	650
Halfway Bush	1956	Monitor	16		
Green Island	1957	Monitor	15		

Substation	Manufacture Year	Status	Number CBs	Replacement Year*	Cost (\$000)
Smith Street	1958	Monitor	15		
Earnsclough	1960	Monitor	1		
Dalefield	1960	Monitor	1		
Outram	1963	Monitor	8		

Table 6.5 – Zone Substation 6.6/11kV Circuit Breaker Replacement Schedule

Note 1: Switchgear replacement part of major substation upgrade - see Section 6.5.2.

Note 2: Switchgear replacement part of major substation upgrade - see Section 5.11.5.

* The “timing” of the projects in this table is nominal and is highly likely to change following economic analysis.

6.5.4 Distribution Circuit Breaker Replacement

A number of distribution substations have oil circuit breakers installed that are in excess of 50 years old, obsolete, and becoming expensive to maintain. At present it is not economic to replace these circuit breakers, but maintenance costs and reliability will continue to be monitored. The applicable sites are listed in Table 6.6, below.

Site	Make	Date of Manufacture	Replacement Date	Estimated Cost (\$000)
Andersons Bay Rectifier	Reyrolle	1948	Monitor	89
Tyne St Rectifier	Reyrolle	1948	Monitor	84
Tennyson St Rectifier	Reyrolle	1948	Monitor	50
Great King St Rectifier	Reyrolle	1948	Monitor	70
Shacklocks	Statter AC2	1960	Monitor	70
High Street	Statter AC2	1960	Monitor	50

Table 6.6 – Distribution Substation HV Circuit Breaker Replacement Schedule

6.5.5 Replacement of Ripple Injection Equipment

Eight of the 18 ripple injection motor/generator sets in the Dunedin area are now over 50 years old, which exceeds their anticipated economic life. Motor failures occurred in January 2002 in Mosgiel and May 2004 at Willowbank. It was possible to source a replacement motor, but should a generator fail it can only be replaced with a static frequency converter at an estimated cost of \$60,000. (Replacement of an entire 1050 Hz injector unit including capacitors is estimated to be at least \$120,000/site.)

It is proposed to replace the eighteen 6.6/11kV 1050 Hz injection plants with three 33kV 317 Hz injection plants – one at the South Dunedin GXP, and two at the Halfway Bush GXP. These would eventually allow the decommissioning of the present plants, installed at each zone substation, when all the receivers have been converted to 317 Hz.

Low frequency 33kV injection is preferred because:

- it should provide better signal propagation;
- capacitors installed on the network do not require blocking chokes;
- 317 Hz relays are less prone to harmonic interference;
- fewer injection units will reduce maintenance costs.

The cost estimate is \$1,450,000 for the injection plants; but in conjunction with the injection plant upgrade, it would be necessary for relay owners to change or convert all of the ripple receivers in the Dunedin area to low frequency 317 Hz relays, at an estimated cost of \$6.2 million. All new receivers being installed can be programmed for operation at 1050 Hz or 317 Hz.

However, new technology such as radio signalling could be a more economic solution. Aurora is waiting on further developments in this field before committing to this project.

6.5.6 Dunedin SCADA RTU Replacements

The SCADA remote terminal units at most Dunedin zone substations were purchased in 1987. These units have been very reliable but face technological obsolescence, due to their inability to use modern master station communication protocols and communicate with Intelligent Electronic Devices (IEDs), such as protection relays. It is estimated that these would cost \$360,000 to replace. When substation switchgear and associated protection systems are replaced, new RTUs are installed as part of the capital renewal budgets.

7 Risk Policies, Assessment, and Mitigation

7.1 Methods, Details and Conclusions of Risk Analysis

Aurora manages risks imposed by technological change, economic alternatives, load changes, embedded generation, and the environment.

7.1.1 Risk Management

DELTA has developed and implemented a risk management policy that defines the approach taken to manage risks associated with the management of Aurora's electricity line business. The primary strategy of this policy is to document all significant risks as they are identified, together with the policies and procedures for eliminating, or reducing and managing the consequences of each risk event. This risk management policy specifies the risk areas for which formal policies will be maintained, as set out in Table 7.1, below.

Generic Risk Area	Sub-Category	Policy Reference
Asset protection	Safe-keeping	<ul style="list-style-type: none"> Electricity Distribution Quality System Risk Management for Electricity Networks Policy (QM20)
	Maintenance of service potential	<ul style="list-style-type: none"> Network Planning Policy
	Replacement planning	
Customer service	Product/service quality	<ul style="list-style-type: none"> Quality System Coverage Scope and Definitions Policy
	Complaints	<ul style="list-style-type: none"> Handling of Complaints Policy
Disaster – fire, flood, earthquake, tsunami, chemical spill, etc		<ul style="list-style-type: none"> Contracting Hazard Register Index Network Risk Management Policy Pandemic Planning Policy
Employment	Employee relations	<ul style="list-style-type: none"> Standard Conditions of Employment Policy Individual Employment Agreement Template
	Health and safety	<ul style="list-style-type: none"> Health and Safety Policy
	Maintenance of work skill capability	<ul style="list-style-type: none"> Training and Staff Competence Pandemic Planning Policy
Environmental protection		<ul style="list-style-type: none"> Environmental Policy
Financial management	Interest rate exposure	
	Liquidity	
	Re-financing	
	Defalcation	
	Fraud	<ul style="list-style-type: none"> Fraud and Other Similar Irregularities Policy Protected Disclosures Policy Delegations Policy

Generic Risk Area	Sub-Category	Policy Reference
Information systems	Financial systems	• Delegations Authorities Policy
	Archives	• Company Filing Policy
	Filing system	
Legal compliance	Health and Safety in Employment Act	▪ Health and Safety Policy
	Electricity Act and associated Regulations	▪ Network Policy
	Resource Management Act	▪ Environmental Policy
	Human Rights Act	▪ Human Rights in Employment Policy
	Local Government Official Information and Meetings Act	▪ Handling of Complaints Policy
	Ombudsmen Act	▪ Handling of Complaints Policy
	Privacy Act	▪ Security of Personal Information Policy
	Protected Disclosures Act	▪ Protected Disclosures Policy

Table 7.1 – Risk Categories and Related Policies

The Asset Management Plan addresses asset related risks only. The scope of other risks that may affect Aurora and its contractors are included above for completeness. The main risks associated with Auroras assets are described below:

7.1.2 Injection Performance (Risk of non-supply from Transpower)

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 embedded generation connected into those GXP systems.

	n-1 Transpower Capacity MVA	Embedded Generation MW	n-1 Security
Halfway Bush	107	44	No ²
South Dunedin	81	-	Yes
Clyde	27	17	Yes
Frankton	76	2	Yes
Cromwell	38	4	Yes

Table 7.2 – Injection Security

Transpower's capacity at Frankton has increased since the release of the last AMP. Section 5.9.5 refers to the fact that 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.

²Refer to Section 5.9.5

7.1.3 **Network Capacity** (ie, adequacy of service)

Aurora's policy is to provide sufficient capacity to meet customers' requirements, subject to satisfactory financial arrangements. For asset management planning, projected demands determine capacity criteria, for which additions and modifications to the network are designed.

Capacity increases to cater for existing and predicted growth are step like in nature. For example, the provision of the new Commonage substation (Section 5.11.8) increases the capacity of the Queenstown CBD and surrounding area by 15 MVA, or 75%. 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 ongoing risk. Equipment is relocated if it is economic to do so.

7.1.4 **Network Reliability** (ie, continuity of service)

Reliability is a function of:

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

While, ultimately, it is customers' requirements and financial commitments which drive work that might alter system reliability, expenditure is presently planned to achieve the supply reliability targets set out in Section 4.3.

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

Probabilistic analysis is used for major plant items, to determine the likelihood of equipment failure and the consequential effects of lost load. Aurora Directors' recent authorisation of renewal of the Ward Street substation (Section 6.5.2) is a result of this form of analysis, concluding that the risk of equipment failure made equipment replacement, which had been foreshadowed in previous AMPs, economic.

Probabilistic analysis is also used to justify small scale projects, such the installation of reclosers to improve SAIDI.

7.1.5 **Works Implementation**

In reviewing the progress of capital works, in particular over the last year, 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 longer lead times than even 24 months ago.

The risk of not obtaining adequate competent human resources for timely design and construction is now believed to be an industry-wide risk. Longer lead times are therefore required, to minimise the possibility of industry peak workloads causing unacceptable pricing of works.

7.1.6 **Safety**

Customer, employee, and public safety are assured by a combination of adequate design, safe operation, and appropriate maintenance of assets.

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. This is achieved by duties set on all parties associated with design, construction, maintenance and operation of Aurora assets.

As an owner and principal, Aurora is required to take all practicable steps to ensure no harm befalls contractors, contractor employees, and others. This is achieved through good design, plant security, safe systems for work access, and contractor selection and monitoring. Contractors are responsible under the HSE Act for safety and competency of their employees working on Aurora assets.

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.

7.1.7 **Environmental Responsibility**

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. One noise complaint was investigated in mid 2002 and was found to be without foundation.

The Act 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.

Aurora is complying with the new tree trimming regulations, (Electricity (Hazards from Trees) Regulations 2003) and is managed by quality policy QP1511.

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.

7.1.8 External Reviews

External reviews of selected aspects of asset management practices are undertaken to ensure that internal mindsets do not occur. External reviews include:

- August 2000. Assessment of network risks in the Central Otago region, focussing on the 33kV system and zone substations.
- November 2001. Assessment of network risks in the Dunedin region, focussing on the 33kV system and zone substations.
- November 2003. This review focussed on environmental aspects of risk assessment. I.e, risks from the environment within which the distribution of electricity occurs, rather than from within the technical infrastructure of the electricity transmission system.
- July 2004. This review focused on fire risks at zone substations, and resulted in minor works being authorised to avoid fire migration from one piece of equipment to another.
- May 2005. All ground-mounted transformers were assessed for risk of vehicle impact and subsequent oil leak into a water way.
- March 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.
- June 2008. Analysis and review of pole inspection records, monitoring, and data capture procedures. This has identified data deficiencies. Improvements to condition data records are planned in mid-2009, following software upgrades.
- Year ending March 2010. A review of structural adequacy of selected zone substation buildings is planned to be completed.

7.2 Details of Emergency Response and Contingency Plans

7.2.1 General

Aurora's Emergency Response Plans consist of a series of quality documents and procedures. They provide both general guidelines and specific instructions for response to abnormal conditions, created by either a civil defence emergency or plant and system failure, and are directed towards minimising the effect of the emergency, and the prioritisation of restoration of electricity supplies.

7.2.2 Civil Defence

DELTA has a comprehensive plan 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.

7.2.3 Routine Emergency Response

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 quality control documents QP1601, QP1602, QP1603, QP1604, QP1605, QP1606, QP1607 and QP1609.

7.2.4 Contingency Plans

DELTA has developed general contingency plans to assist in the timely restoration of supply following an outage to a major distribution feeder or zone substation. These are recorded in QP 1602/21. It should be noted that it is not possible to offload peak loads at most substations for potentially rare “n-2” events; ie, transfer a complete substation’s load for a combined failure, such as both subtransmission circuits or both transformers at the larger substations.

8 Performance Measurement, Evaluation and Improvement

8.1 Review of Network Service Level Performance

These are summarised in Appendix B.

8.1.1 Reliability

The System Average Interruption Duration Index (SAIDI) provides an overall measure of asset performance for the year. This is shown in Table 8.1 below along with unplanned System Average Interruption Frequency Index (SAIFI).

Category	07-08 Plan	07-08 Actual
SAIDI	Minutes	Minutes
Unplanned		
Underlying	63	55.3
Significant events	10	60.7
Planned	15	13.3
	<u>88</u>	<u>129.3</u>
Transpower	1	11.0
TOTAL	<u>89</u>	<u>140.3</u>
SAIFI	Interruptions	Interruptions
Unplanned by Aurora	1.36	1.37

Table 8.1 – Expected v Actual SAIDI Minutes and SAIFI 2007-2008

System performance is categorised to eliminate causes outside Aurora's normal span of control; specifically the results of Transpower initiated outages, or significant storm events. The resultant underlying system performance is the area that is closely monitored to identify areas for improvement. Significant or storm events are also analysed to identify areas for improvement that may produce a cost effective means of minimising disruption from those events.

For unplanned interruptions, the “underlying” pattern was 7.7 minutes below target. However, significant events were considerably over target, mainly due to severe winds on 10 and 11 of August 2007 in the Central region, and 23 October 2007 in Dunedin. Transpower interruptions were over target by 10.0 minutes. These events resulted in the total being 57.6% over target.

Planned interruptions were 1.7 minutes below the 2007-08 target figures, despite a continued high level of network growth. Wherever economic, contractors use live line techniques to connect new extensions to the network.

8.1.2 Faults per 100km HV Circuit

The number of faults per 100km of line for the year 1 April 2007 to 31 March 2008 was 11.4, reduced from 13.3 after increased expenditure on tree trimming.

8.1.3 Low Voltage Complaints

Seventeen valid voltage complaints were received for the year 1 April 2007 to 31 March 2008. This is an increase of 2 from the previous year, but is acceptable considering the record demand experienced in the winter of 2007 as it is well below the target of 10/10,000 connections..

8.1.4 Environmental Performance

There were no reported environmental incidents for the year 1 April 2007 to 31 March 2008.

8.2 Review of Financial Performance

8.2.1 Maintenance Expenditure

For the year in review, planned maintenance activities have generally been completed in line with maintenance standards.

A comparison of Aurora's maintenance expenditure against budget is shown in Table 8.2, below:

Category	2007/08 Actual	2007/08 Budget	Variance	
	\$000	\$000	\$000	%
Subtransmission	1,059	927	132	21%
Zone substations	1,440	988	452	46%
System control	118	149	-31	-21%
HV and LV lines and cables	5,113	5,493	-380	-7%
Distribution substations	844	1,017	-173	-17%
Undergrounding Expense	428	210	218	104%
Third Party Damage	422	252	170	67%
Total	9,424	9,036	388	4%

Table 8.2 – Maintenance Expenditure Budget Compared to Actual

Variances from budget are discussed below:

- The primary causes for subtransmission system unfavourable variance were: a severe wind storm on 10 and 11 August 2007 which caused loss of supply to Wanaka for ten hours, higher than expected fault incidence of 33 kV cable faults in Dunedin, and increased tree trimming to improve system security.
- The zone substation unfavourable variance was caused by a succession of individual, unrelated, small faults, such as tapchanger repairs, as well as programmed inspection and maintenance for items such as earth grids. Costs relating to the major failure of Halfway Bush T2 in November 2006 are also included in this period.
- HV and LV lines and cables were under budget due to the diversion of resources to subtransmission lines as mentioned above.

- Underground conversion costs were higher than budgeted due to higher than anticipated costs.
- Third party damage was higher than budgeted.

8.2.2 Capital Expenditure

A comparison of Aurora's capital expenditure budget is shown in Table 8.3, below:

Category	2007/08 Actual (\$000)	2007/08 Budget (\$000)	Variance (\$000)	
New connections	8,327	8,200	127	1%
Localised growth	3,889	3,100	789	25%
System development	2,760	5,102	-2,342	-46%
Undergrounding projects	1,707	2,832	-1,125	-40%
Total	16,683	19,234	-2,551	-13%

Table 8.3 – Comparison of Actual Capital Expenditure with Plan

The causes of variances are:

- New connections work, which is consumer initiated, was higher than budget due to demand by developers and new consumers.
- Localised growth is a combination of planned works required to meet growth and works required for the correction of voltage complaints. This was above budget primarily due to network reinforcement in the Frankton area, expensive to resolve voltage complaints, and pedestal transformer removal.
- Within the System Development category, the completion of the Queenstown and Frankton cable projects was required to maintain subtransmission security. These projects required significant resources, which were consequently not available for other projects such as undergrounding. These projects were completed after 31 March 2008.

As at 31 March 2008, Aurora had \$7,089 million of works under construction; major items are detailed in Table 8.4 below:

Item	Value (\$000)	Status
Mobile substation	1,200	Equipment ordered
Berwick zone substation	530	Commissioned in May 2008
Cardrona substation	705	Equipment installed by May 2008
Frankton and Queenstown subtransmission cables	1,328	Commissioned in May and June 2008
Undergrounding projects	950	Projects designed and cable ordered

Table 8.4 – Projects Under Construction

8.3 Gap Analysis and Identification of Improvement Initiatives

Both planned and unplanned maintenance activities are analysed to monitor performance trends, and to evolve both maintenance practices and replacement policies. No changes to current practices have been made in the last year; however some policies are being externally reviewed to confirm that they still meet best practice.

All unplanned interruptions exceeding 0.5 SAIDI minutes are subjected to an engineering investigation, and a summary report provided to the Aurora Board. These reports specifically identify improvements to material selection, items of plant, design, configuration, and operation. No systemic equipment failures were identified within these reports in the last year.

Recently identified improvements have included:

- replacing the Mosgiel 11 kV switchgear due to reliability concerns (underway);
- Berwick zone substation upgrade (substantially complete as at 31 March 2008);
- installation of voltage regulators at the Pisa Moorings (completed in the March 2009 year);
- installation of reclosers to improve reliability in the Ettrick and Poolburn areas (completed);
- SCADA improvements to the Central network (ongoing);
- data quality improvements to GIS records, when economic to do so (ongoing);
- renewal of the Ward Street Zone Substation (approved, transformers ordered, expected completion by the winter of 2010).

The use of RCC Ground Fault Neutralisers has been considered and is not yet considered to be economic. This will be reviewed annually by liaising with other networks who are trialling them.

Further studies regarding potential projects to maintain/improve reliability are underway. These may result in new projects being identified and described in future AMPs.

Glossary of Terms

CPD	Congestion Period Demand
CAIDI	Consumer Average Interruption Duration Index
CODC	Central Otago District Council
DCC	Dunedin City Council
DGA	Dissolved Gas Analysis
DRC	Depreciated Replacement Cost
DSM	Demand Side Management
GXP	Grid Exit Point
HWB	Halfway Bush
Hz	Hertz
IEDs	Intelligent Electronic Devices
MDIs	Maximum Demand Indicators
MVA	Mega Volt-Amps
MW	Mega Watts (one million watts)
pf	power factor
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

Appendix A – Major Capital Projects

Further descriptions for each project are provided within Sections 5 and 6 of this AMP.

Year ending March	Project Name	Status	Value \$(000)	Section #
2009	Mosgiel switchgear	Underway	\$650	5.11.3
2009	Mobile substation	Underway	\$1,400	5.11.4
2010	Commonage substation	Underway	\$5,000	5.11.8
2011	Ward Street substation	Underway	\$4,600	6.5.2
2011	Cardrona substation and lines	Proposed	\$4,300	5.10.2
2011	Frankton switchgear	Proposed	\$1,000	5.11.5
2011	Jack's Point substation	Designation applied for	\$1,300	5.11.9
2012	East Taieri transformers	Proposed	\$2,400	5.11.3
2012	Cromwell Transformers	Proposed	\$400	5.11.7
2012	Arrowtown substation	Proposed	\$2,000	5.11.2
2012	Dunedin ripple injection	On hold	\$1,450	6.5.6
	Wanaka to Hawea line	Proposed	\$1,000	5.10.3
	Neville Street Cables	Review Annually		3.8/6.5.1

Appendix B – Service Level Targets

Service Criteria	Performance Indicator	Target 2008/09 to 2017/18	Actual 2007/08
Supply quality	No of proven voltage complaints per 10,000 consumers	10	1.6
Operating efficiency	Losses	6%	5.6%
Operating efficiency	Faults per 100 km line	11.1	11.7
Operating efficiency	Distribution transformer utilisation - kVA capacity per peak demand kW	30%	33.7%
Operating efficiency	Load Factor - Network Input GWh / Peak MW * Hrs per year	52%	54.7%
Environmental effectiveness	Incidents of contaminant spill from network	0	0
Safety	Staff and Contractors serious harm incidents	0	0
Safety	Public injury incidents	0	0

SAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIDI
Actual	1999/00	18.9	175.7	194.6	-	13.4	13.4	208.0
	2000/01	16.7	62.4	79.1	-	3.3	3.3	82.4
	2001/02	13.8	61.5	75.3	-	13.4	13.4	88.7
	2002/03	20.5	68.6	89.1	-	12.1	12.1	101.2
	2003/04	16.3	80.0	96.3	-	1.0	1.0	97.3
	2004/05	7.3	73.2	80.5	-	-	-	80.5
	2005/06	11.7	70.8	82.5	-	14.0	14.0	96.5
	2006/07	13.2	83.5	96.7	-	4.7	4.7	101.4
	2007/08	13.3	116.0	129.3	-	11.0	11.0	140.3
Target	2008/09	15.0	73.0	88.0	-	-	-	88.0
	2009/10	15.0	72.0	87.0	-	-	-	87.0
	2010/11	15.0	71.0	86.0	-	-	-	86.0
	2011/12	14.0	71.0	85.0	-	-	-	85.0
	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	66.0	79.0	-	-	-	79.0

SAIFI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIFI
Actual	1999/00	0.12	1.62	1.74	-	0.45	0.45	2.19
	2000/01	0.11	1.19	1.30	-	0.11	0.11	1.41
	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
Target	2008/09	0.13	1.33	1.46	-	-	-	1.46
	2009/10	0.13	1.31	1.44	-	-	-	1.44
	2010/11	0.13	1.29	1.42	-	-	-	1.42
	2011/12	0.12	1.27	1.39	-	-	-	1.39
	2012/13	0.12	1.26	1.38	-	-	-	1.38
	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	1.20	1.31	-	-	-	1.31

CAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall CAIDI
Actual	1999/00	159.9	108.3	111.8	-	29.6	29.8	95.0
	2000/01	158.6	52.6	60.8	-	29.2	30.0	58.4
	2001/02	81.7	42.2	48.3	-	59.0	58.3	49.6
	2002/03	134.9	50.6	59.0	-	21.3	21.2	48.7
	2003/04	119.9	54.5	59.8	-	8.8	9.1	56.6
	2004/05	100.2	52.8	55.1	-	-	-	55.1
	2005/06	135.7	50.5	55.4	-	60.0	60.9	56.1
	2006/07	127.0	52.6	57.2	-	35.6	36.2	55.7
	2007/08	129.5	84.6	88.0	-	31.4	31.4	77.1
Target	2008/09	120.0	55.0	60.0	-	-	-	60.0
	2009/10	120.0	55.0	60.0	-	-	-	60.0
	2010/11	120.0	55.0	60.0	-	-	-	60.0
	2011/12	120.0	55.0	60.0	-	-	-	60.0
	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

Appendix C – Compliance Matrix

Revised Information Disclosure Requirements October 2008

	Requirement	AMP Location
4.5.1	Summary of the Asset Management Plan	1
4.5.2	Background and Objectives <ul style="list-style-type: none"> (a) Purpose of the plan. (b) Interaction of objectives with other corporate goals, business planning processes and plans. (c) Period to which the plan relates and date approved by board of directors. (d) Stakeholder interests. (e) Accountabilities and responsibilities for asset management. (f) Details of asset management systems and processes including asset management systems/software and information flows. 	2.1 2.2 2.2 / 2.3 2.4 2.5 2.6
4.5.3	Assets Covered <ul style="list-style-type: none"> (a) High level description of the distribution area. (b) Description of network configuration. (c) Description of network assets by category including age profiles and condition assessment. (d) Justification for the assets. 	3.1 3.2-3.3 3.5-3.8 3.9
4.5.4	Service Levels <ul style="list-style-type: none"> (a) Consumer oriented performance targets. (b) Other targets, e.g. – asset performance, asset efficiency and effectiveness, the efficiency of the lines business activity. (c) Justification for target levels of service based on consumer, legislative, stakeholder and other considerations. 	4.1 4.4 4.6-4.8
4.5.5	Network Development Planning <ul style="list-style-type: none"> (a) Description of the planning criteria and assumptions. (b) Description of the prioritisation methodology adopted for development projects. (c) 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. (d) Distributed generation policy. (e) Non-network solution policy. (f) Analysis of network development options available and details of the decisions made to satisfy and meet target levels of service. (g) Description and identification of the network development programme and actions to be taken, including associated expenditure. 	5.4 / 5.8 5.5 / 5.7 5.1 / 5.6 5.9 5.2 5.3 5.1 / 5.0 / 5.14/ 5.15 5.1 / 5.10 – 5.16

	Requirement	AMP Location
4.5.6	Lifecycle Asset Management Planning (Maintenance and Renewal) <ul style="list-style-type: none"> (a) Description of maintenance planning criteria and assumptions. (b) Description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including expenditure projections. (c) Description of asset renewal and refurbishment policies. (d) Description and identification of renewal or refurbishment programmes or actions to be taken for each asset category, including associated expenditure projections. (e) Asset replacement and renewal expenditure. 	6.1 6.2 6.3 6.3 6.4 6.4
4.5.7	Risk Management <ul style="list-style-type: none"> (a) Methods, details and conclusions of risk analysis. (b) Details of emergency response and contingency plans. 	7.1 7.2
4.5.8	Evaluation of Performance <ul style="list-style-type: none"> (a) Review of progress against plan, both physical and financial. (b) Evaluation and comparison of actual performance against targeted performance objectives. (c) A gap analysis and identification of improvement initiatives. 	8.1 / 8.2 8.1/5.14 /4.1/Ap C 8.3