AURORA ENERGY LTD

Asset Management Plan
Number 13

April 2006-March 2016

Revised 25 August 2006

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

Date approved by Aurora Board : 30 August 2006

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F O R E W O R D

This is the thirteenth Network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd and covers the 10 year period from 1 April 2006. It documents existing and projected network asset conditions and the likely or intended asset management programmes, based on the present understanding of customer requirements. 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 only indicative, Aurora Energy Ltd will not accept responsibility for decisions by others, which are based upon information contained in it. 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

This summary of the plan is to provide a brief overview which highlights information that Aurora Energy Ltd (Aurora) considers significant. A glossary of technical terminology appears in Section 9.

1.2 Background and Objectives

The purpose of this document is to describe, in accordance with the Commerce Commission Electricity Information Disclosure Requirements 2004 and amendments, the asset management objectives, plans and systems adopted by Aurora for the lines business assets it owns.

1.3 Assets Covered

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.

Asset Category	Quantity	RC	% by $
Subtransmission	591 km	$41,437,526	10%
Zone substations	36	$75,446,620	18%
HV distribution	3,002 km	$126,146,640	30%
Distribution switchgear	11,289	$37,174,785	9%
Distribution transformers	5,793	$47,875,000	11%
Distribution substations	5,740	$10,199,000	2%
LV distribution	1,597 km	$68,925,011	16%
Service connections	76,430	$11,265,095	3%
Street lighting distribution	142 km	$4,791,006	1%
System control		$1,611,200	< 1%
Sundry		$562,593	< 1%
Total		**$425,434,475**	**100%**

Table 1.1 – Types and Quantities of Assets (from March 2005 ODV)

Approximately 2.1% (by Depreciated Replacement Cost, DRC) of existing assets have 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

Aurora's primary service level target for asset performance is continuously tested by market survey, for which a response rate of 18% is achieved.

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

Function	Objective
General Network Performance	Average of no more than 90 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 urban, 6 hours rural of notification.

Table 1.2 – Service Level Objectives

Aurora's primary service level focus is SAIDI; other indicators are considered to be secondary. Given the above market survey response that consumers do not want to pay for improved reliability, Aurora believes that maintaining the target of 90 SAIDI minutes is appropriate.

1.5 Network Development Plans

New capital works are driven by: demand growth by existing consumers and 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 whether equipment replacement or new capital works are economic. The capital expenditure as shown in Table 5.2 is summarised below:

Table 5.2	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Total	13,960	15,380	15,660	16,150	16,090	16,960	17,380	17,820	18,270	18,600

1.6 Lifecycle Asset Management Planning

Aurora's maintenance strategy is based on careful and continuous monitoring of asset condition.

Asset management policy is to evaluate and balance the cost of maintenance against the prospective cost of failure, refurbishment/renewal costs as well as the cost of non-supply. Likewise, asset renewal is determined when the Net Present Value (NPV) of the new asset exceeds the NPV of non-renewal.

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 continuously monitored and are subject to change as optimum levels evolve. No significant change in maintenance policies is planned. The maintenance expenditure from Table 6.1 and Table 6.2 are summarised below in Table 1.3.

[♦] For Retailers using the standard Use-of-System Agreement dated July 2005.

Financial Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Inspection (Table 6.1)	1,096	1,110	1,151	1,178	1,206	1,235	1,265	1,295	1,326	1,358
Maintenance and Refurbishment Costs (Table 6.2)	9,860	9,999	10,357	10,604	10,857	11,116	11,381	11,653	11,932	12,218
Total Maintenance Expenditure	10,956	11,110	11,508	11,782	12,063	12,351	12,918	13,227	13,258	13,576

Table 1.3 – Total Maintenance Expenditure ($000)

1.7 Risk Management

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

(1) responsibilities dictated by the Resource Management Act;
(2) security of major items of plant;
(3) 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.

1.8 Evaluation of Performance

The diagram below compares the performance achieved by Aurora's network with that achieved by other line businesses in the year to 31 March 2005.

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 was in the 'best-performer quartile' of the 28 distribution businesses.

While such analysis is not a perfect indicator, it provides a great degree of confidence that Aurora's overall performance is entirely satisfactory.

[1] SAIDI = system average interruption duration index minutes

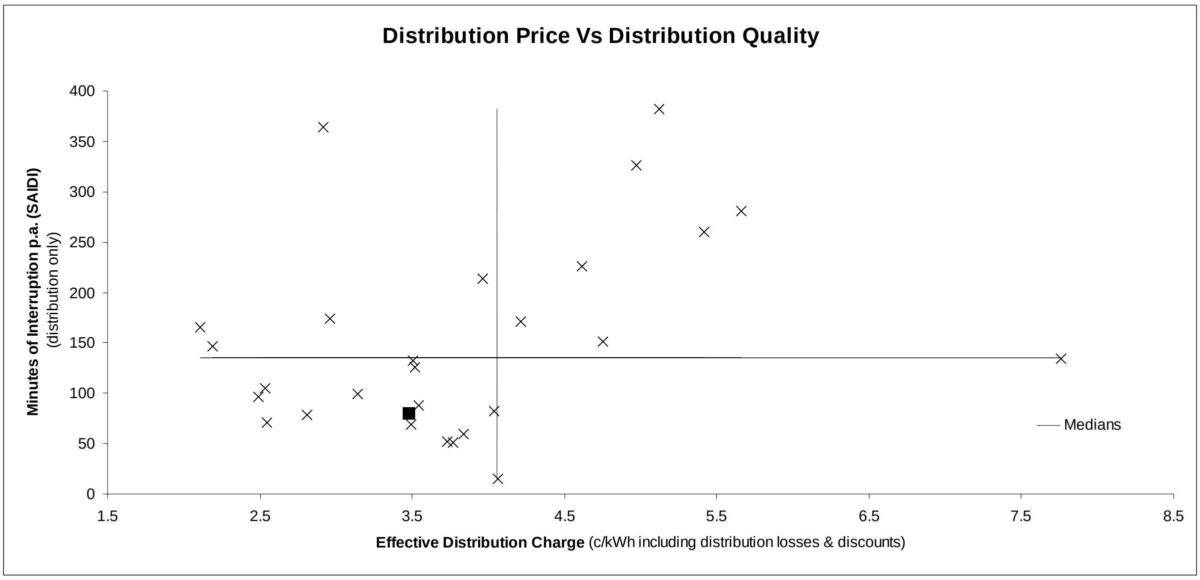

Figure 1.1 – Price-Quality Matrix

1.9 Stakeholder Consultation

Aurora's process for continual improvement will continue to be focussed on optimising the trade-off between price and quality. To this end, Aurora invites questions, comments and suggestions for improvement 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 disclosure concentrates on asset management principles and overall indicators of asset condition and performance. Existing or potential users of the 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. No comment has been received in response, other than from the Commerce Commission and its agents.

2 Background and Objectives

2.1 Purpose

The purpose of this document is to describe, in accordance with the Commerce Commission Electricity Information Disclosure Requirements 2004 issued 31 March 2004 and Amendments, the asset management objectives plans and systems adopted by Aurora Energy Ltd (Aurora) for the lines business assets it owns.

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

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

Aurora has four levels of corporate planning; a strategic plan, an asset management plan, a six year development plan and an annual budget. All are reviewed annually

This asset management plan covers the period from 1 April 2006 to 31 March 2016 and represents an evolution of the annual Asset Management Plan published for the Dunedin network since 1993.

Aurora maintains a rolling six-year network development plan, which outlines potential specific asset developments to provide for anticipated load growth and appropriate asset replacement. This is approved by the Board prior to the review of the asset management plan and the setting of annual budgets. It forms the basis of the proposed capital works programme contained herein.

The Board approved this (2006 – 2016) Asset Management Plan on 30 August 2006.

2.3 Period to Which Plan Relates

This plan relates to the 2006-2016 period.

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

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 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 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	Compliance with statutory requirements Economic efficiency
Land Owners 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
Transit NZ Transpower	Control of assets in road reserve Reliability of supply Investment for growth

Table 2.1 – Stakeholder Interests

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

The Board will decide 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 after 31 March 2013 expires. Some parties have forecast that electricity supply to certain consumers will then cease, or continue only under much higher charges.

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.

2.5 Accountabilities and Responsibilities

Aurora has contracted asset management to related company *DELTA* under a 10-year performance-related contract that expires on 30 June 2008. 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.

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 Manager and *DELTA*'s Network Services Manager who together form the network management group within *DELTA*.

The Engineering Services Manager responsibilities include asset planning, asset management including contractor and records management, outage management, and the capital expenditure program.

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

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 2004 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 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 livening.
- 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.

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*.

Some systems, processes and technologies vary between the Dunedin and Central areas due to investment decisions which occurred before Aurora acquired the Central area assets in 1999.

3 Assets Covered

3.1 High Level Description

3.1.1 Areas Covered

The Aurora network covers two geographically separate areas, the Dunedin network area and Central Otago network area as shown in Figure 3.1. The Central region is characterised by its separate valley areas mandating a radial network supplied from three transmission grid exit points (GXPs). There are no Aurora interconnections between the Central GXPs. The Dunedin region is supplied from two GXPs with significant Aurora interconnection between them.

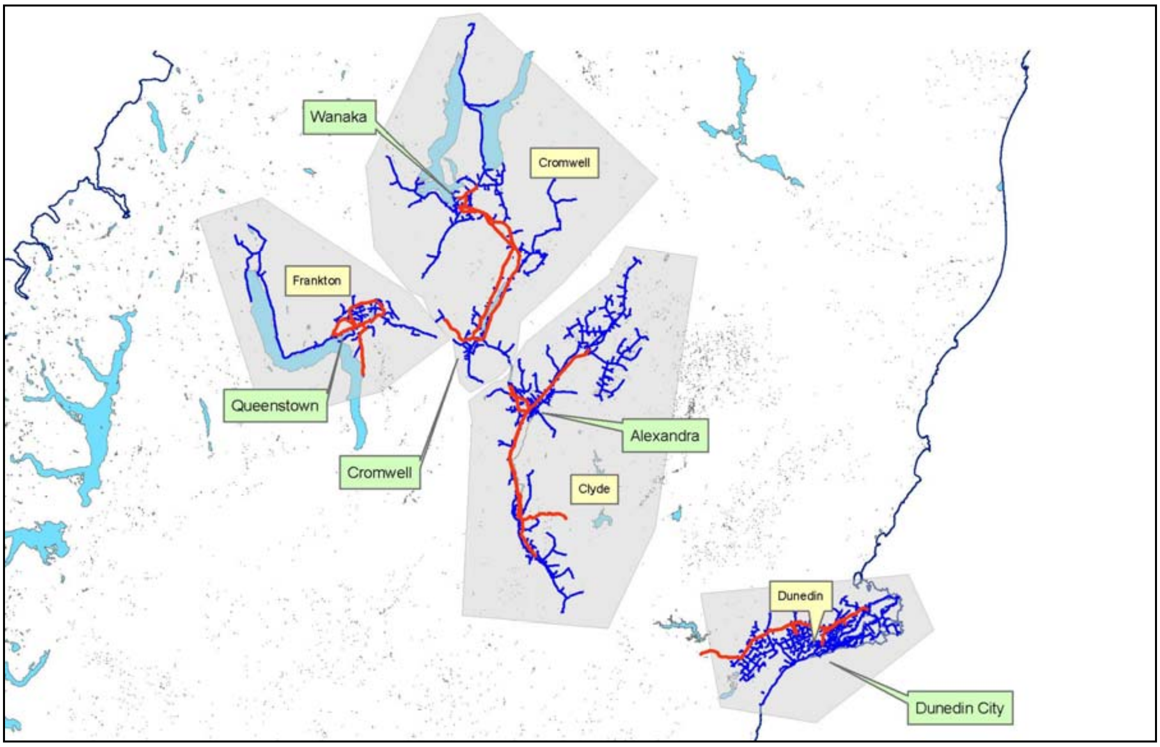

Figure 3.1 – Aurora Network

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 as there is very little industrial load. All GXP areas have their peak demand in winter. The daily peak loads for 2005 for each GXP are shown in Figure 3.2.

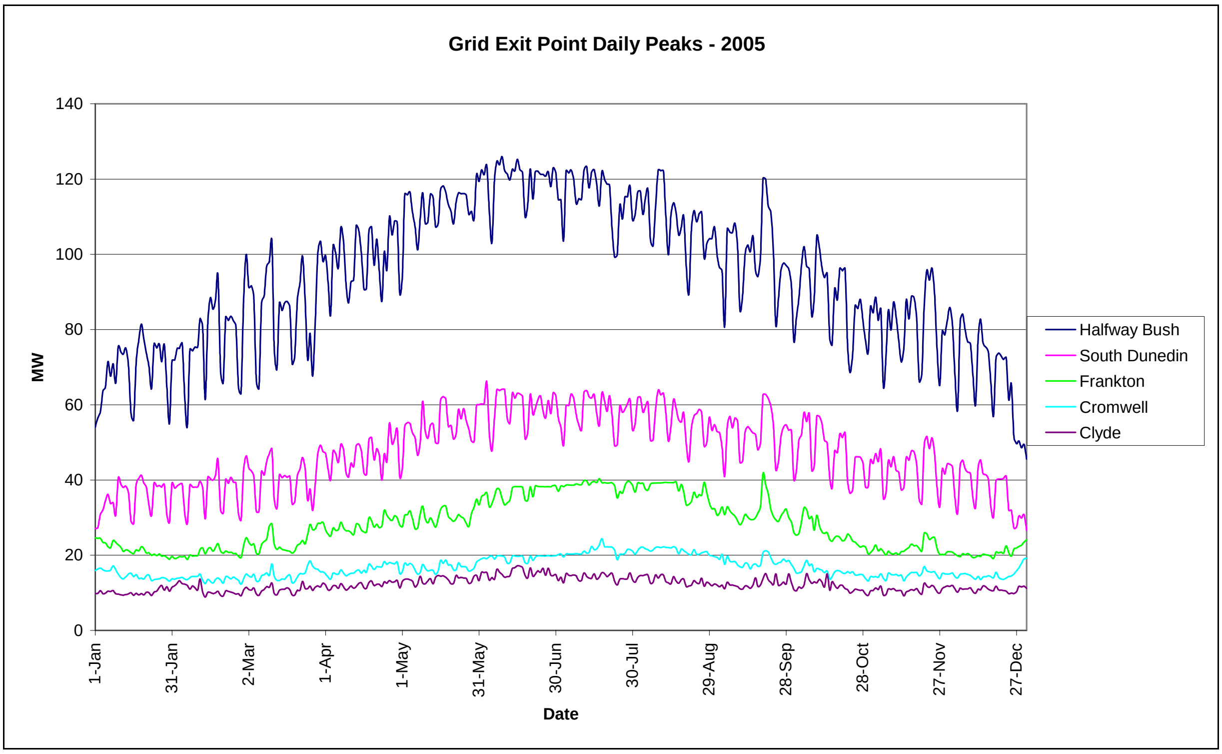

Figure 3.2 - Graph of GXP Daily Peaks for 2005

The Frankton and Cromwell GXP peak loads generally occur during the July school holidays due to the influx of skiers into the area. There has been significant growth in summer irrigation load from the Cromwell GXP such that one zone substation has a summer peak.

The Clyde GXP serves Alexandra, Roxburgh and surrounding areas and load also peaks in winter. In some areas supplied from Clyde 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 snow fall event in the city which can happen any time 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 observed in Central.

3.1.4 **2005 Load Data**

The key load and embedded generation statistics for the 2005 calendar year are presented in Table 3.1.

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2005 peak MW	15.6	24.4	41.8	126.0	66.1	274.1
2005 energy transported GWh	79.8	109	190.8	612.5	313.3	1305
Total number of ICPs*	6,321	8,420	10,028	35,471	16,265	76,505
2005 GXP peak (MW) (excludes embedded generation)	6.5	21.1	40.2	111.9	66.1	
GXP n-1 capacity (continuous) MVA	27	35	33	100	81	
GXP n-1 capacity (24 hr winter post contingency) MVA	27	35	41	112	81	
Embedded generation (2005 MW at time of GXP peak)	4.6	3.3	1.6	3.9	0	
Embedded generation (2005 MW at time of system peak)	13.6	3.3	1.6	19.9	0	41.1

Table 3.1 - GXP Load and Capacity Summary for 2005 Calendar Year

***Note** that this is at December 2005 so these figures do not match those given in Table 1.1 which is based on March 2005 data.

3.2 Network Configuration

The Aurora network is supplied from five Transpower grid exit points as detailed above.

The significant embedded generation at each GXP is detailed in Table 3.2.

GXP	Embedded Generation	Connection Voltage	Installed Generation Capacity
Halfway Bush	Waipori Ravensdown Fertiliser Dunedin Airport	33kV 6.6kV 11kV	44MVA 2.8MVA 0.5MVA
South Dunedin	None		
Frankton	Glenorchy Wye Creek	11kV 33kV	0.5MVA 1.3MVA
Cromwell	Roaring Meg Treble Cone (No export)	33kV 11kV	4.3MVA 1MVA
Clyde	Fraser Teviot	33kV 33kV	2.5MVA 14.8MVA

Table 3.2 - Schedule of Embedded Generation

3.3 Sub-Transmission

3.3.1 Dunedin Area

The Dunedin city urban area is supplied from the Halfway Bush and South Dunedin GXPs. There are 19 33kV feeders 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 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.

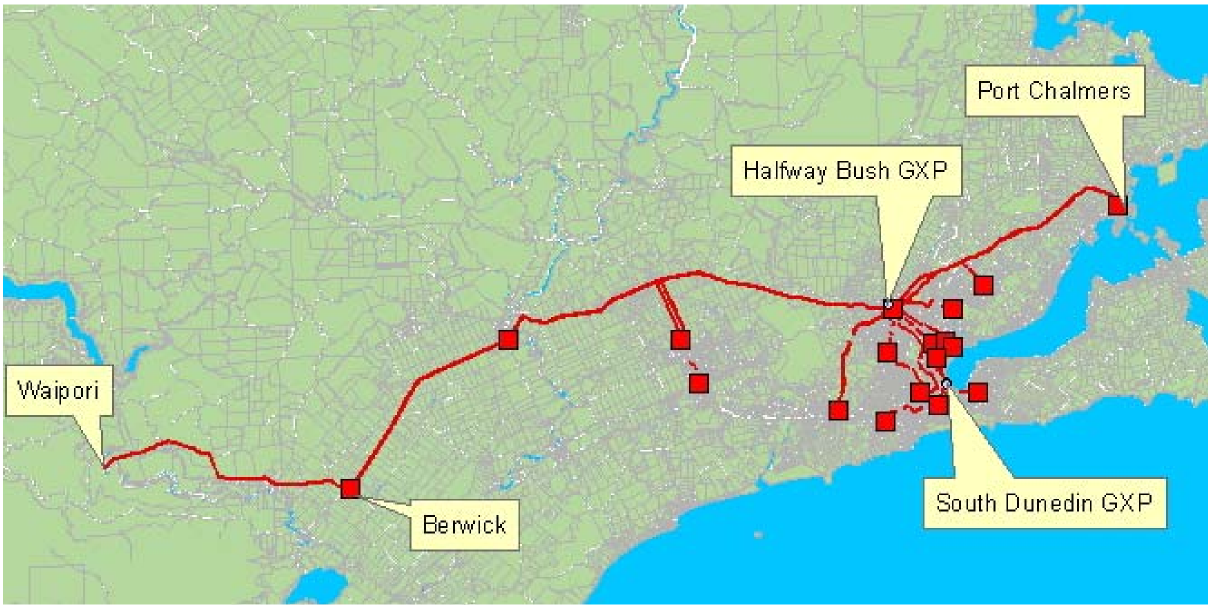

Figure 3.3 - Dunedin Sub-Transmission Network

Grid Exit Point	Zone Substation	Transformer Capacity MVA	Sub-Transmission	n-1 Security
Halfway Bush	Berwick	1 +1	Selectable to any of the three Taieri 33kV sub-transmission lines	Y
	East Taieri	12/24 + 12/24	Two 33kV Oil Cables via Mosgiel and Taieri Sub-transmission 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 sub-transmission 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 sub-transmission 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
South Dunedin	Andersons Bay	15 +15	Two 33kV gas cables from Sth Dn GXP	Y
	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 five 33kV outlets from the Frankton GXP. Two circuits supply the Wakatipu Basin via a ring and there are three parallel lines from Frankton to Queenstown. A 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.

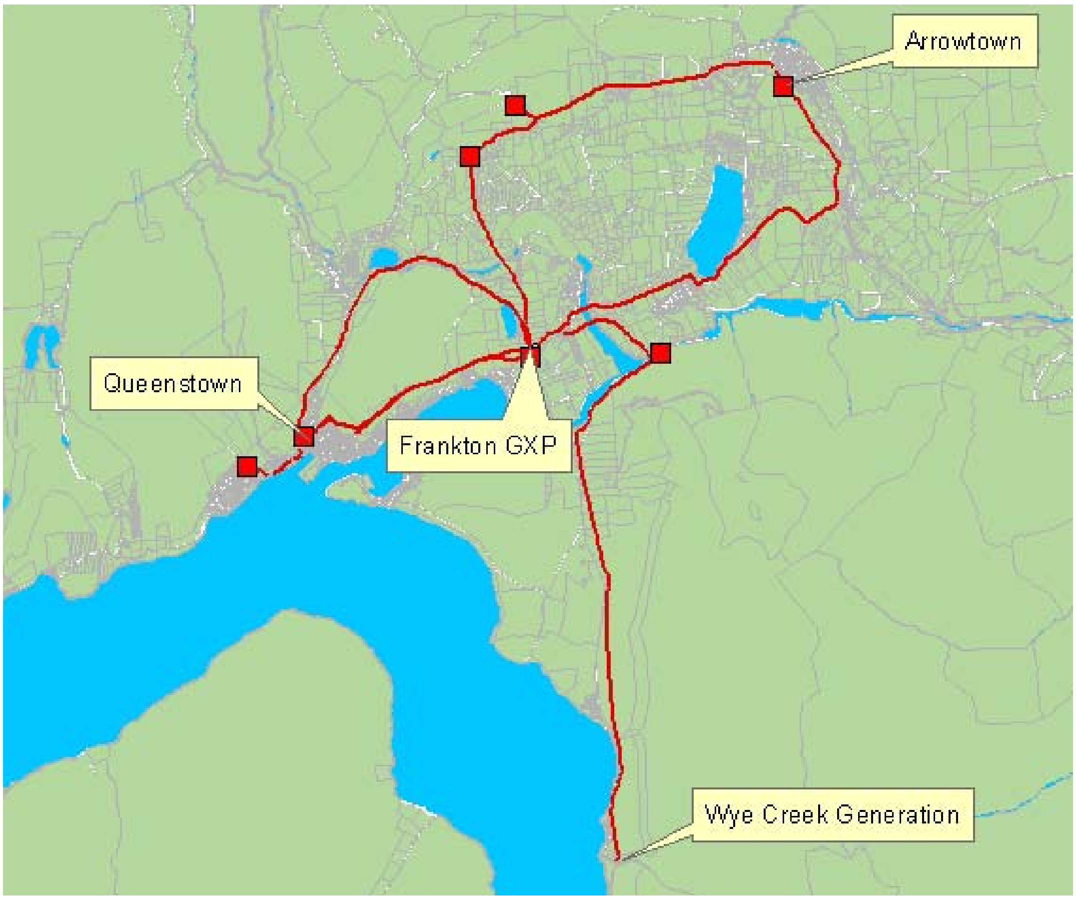

Figure 3.4 - Frankton Sub-Transmission Network

Substation	Transformer MVA	Sub-Transmission 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	7.5/15 +7.5/15	Tee off two of Queenstown to Frankton lines	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 Frankton Area

3.3.3 Cromwell Area

The Cromwell area is supplied via four 33kV outlets at the Cromwell GXP. Two of the outlets supply two 33/66kV 30MVA auto transformers adjacent to the GXP that supply the Wanaka area via two parallel 66kV transmission lines. The other two outlets supply the Aurora Cromwell zone substation and provide a connection to the Meg generation. The transformers at Wanaka are three winding units 66/33/11kV. The 33kV windings are used to supply the Maungawera substation. An overview of the network is shown in Figure 3.5 and zone substation details are in Table 3.5.

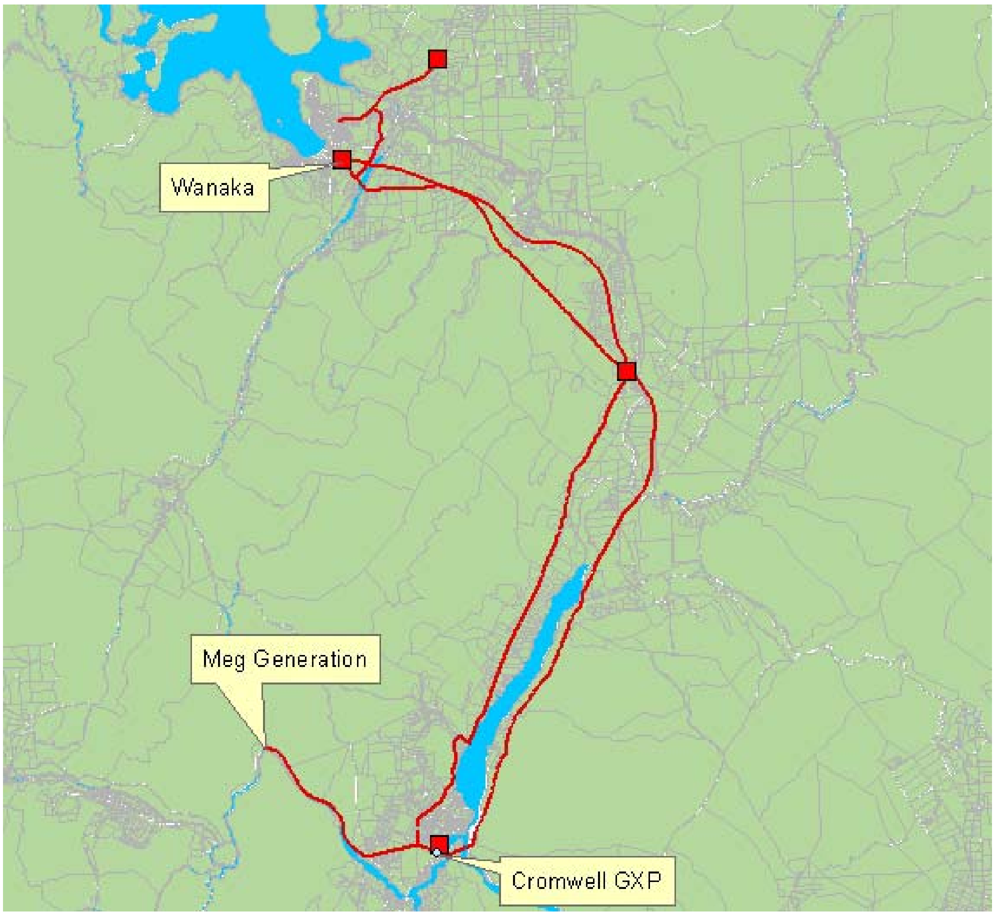

Figure 3.5 - Cromwell Sub-Transmission Network

Substation	Transformer MVA	Sub-transmission 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 outlets at the Clyde GXP. These outlets supply Alexandra via a parallel pair of transmission 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. An overview of the network is shown in Figure 3.6 and zone substation details are in Table 3.6.

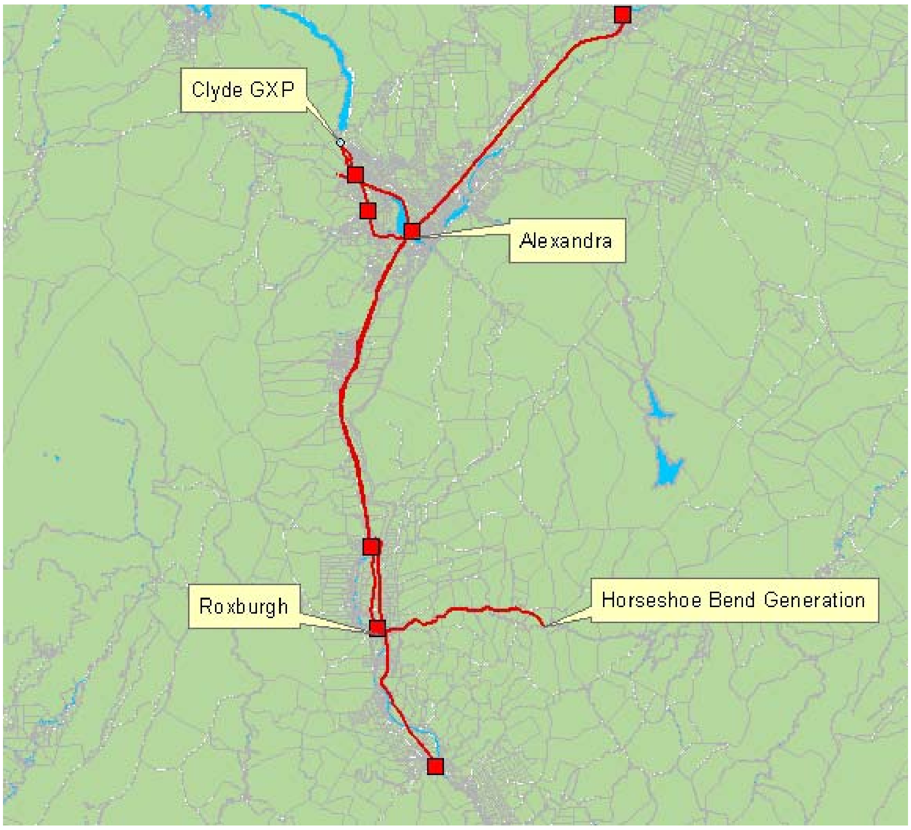

Figure 3.6 - Clyde Area Sub-Transmission

Zone Substation	Transformer MVA	Sub-Transmission 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 - Clyde Area Zone Substations

3.4 HV Distribution

All HV mains are owned by Aurora, except for registered HV consumers and where consumers specifically request to retain ownership.

3.4.1 Dunedin Area

HV distribution in the Dunedin area is via 182 HV feeders. Four zone substations 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 interties to other feeders, except for the supplies to Otago University and the Hillside Workshops which have paralleled feeders. HV cables in the Dunedin area are predominately PILC (96%) with the remaining 4% being XLPE. (*9% of cable insulation could not be confirmed as it is uneconomic to do so and so is a low priority.)* For many years, all new cable has been rated for 11kV operation even when it operates at 6.6kV.

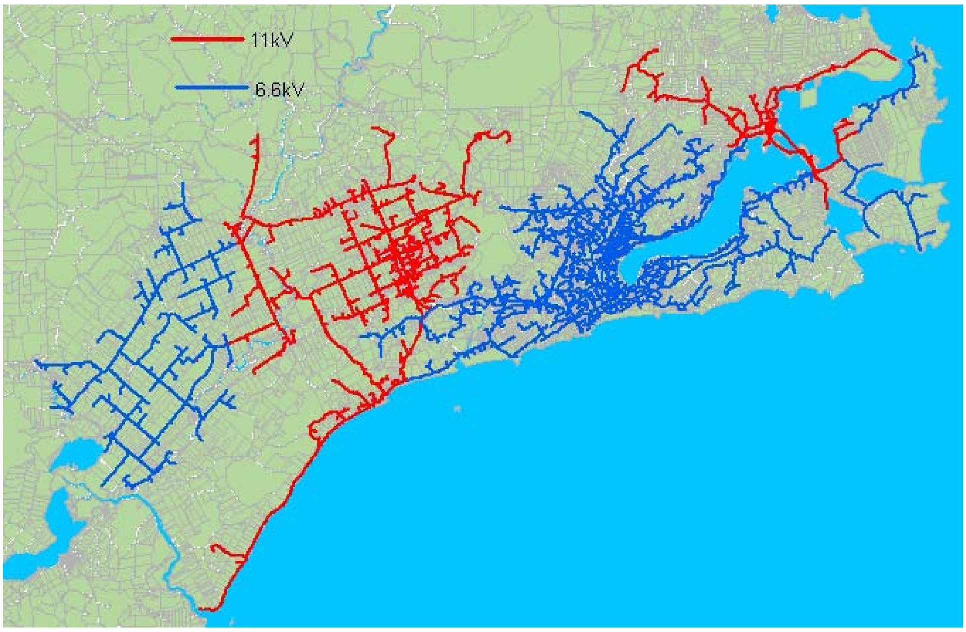

Figure 3.7 - Dunedin HV Distribution by Voltage

Voltage	km	% Overhead	% Underground
11kV 6.6kV	323 699	85% 68%	15% 32%
Total	1,021	73%	27%

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. 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 in the Central area is a mix of PILC (33%) and XLPE (67%). (*12% of cable insulation could not be confirmed as it is uneconomic to do so and so is a low priority.*) In Central, there is a significant quantity of rural HV cable due to local authority requirements and the high number of rural lifestyle subdivisions.

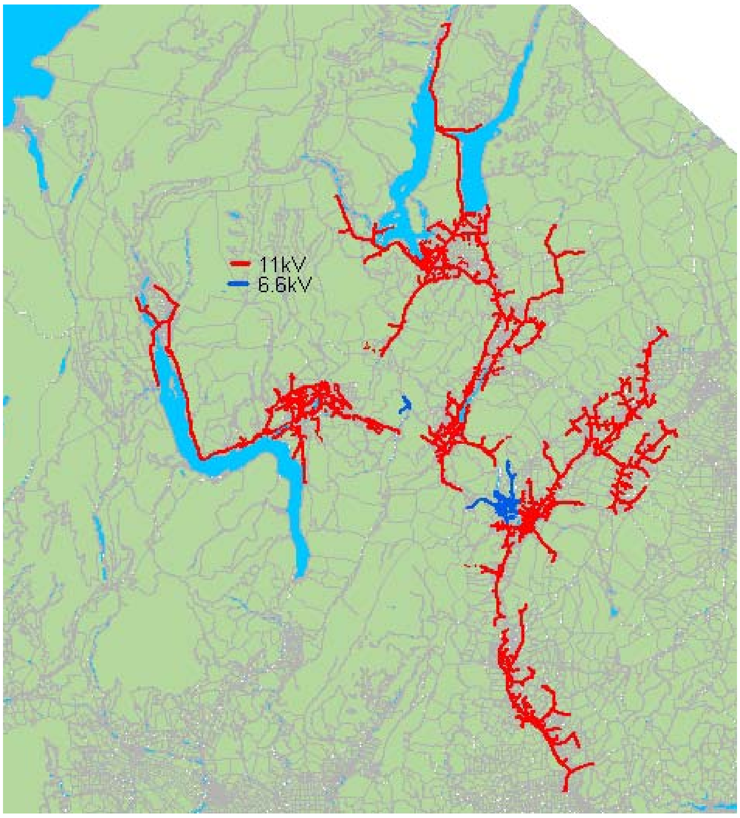

Figure 3.8 - Central HV Distribution by Voltage

Voltage	km	% Overhead	% Underground
11kV 6.6kV	1,885 77	82% 91%	18% 9%
Total	1,962	83%	17%

Table 3.8 - Central HV Distribution Quantities

3.5 Distribution Substations

The quantities of each type of substation owned by Aurora are detailed in Table 3.9. Note that in the following tables quantities will differ from Table 1.1 as Table 1.1 is based on March 2005 data.

Substation Type	Count
Pole Mounted	4,528
Pedestal Mounted	27
Ground Mounted	2,116
Underground	20
Total	6,691

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.

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 fibre-glass enclosure with associated HV switchgear and LV distribution board. This configuration is <u>no longer used for new substations</u>.

Mini (Standard)
These substations are proprietary made 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 generally have a 1000kVA capacity.

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 <u>no longer used for new substations.</u>

3.6 LV Distribution

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 Central	989 647	83% 39%	17% 61%
Total	1,636	65%	35%

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 in the last twenty years.

3.7 Secondary Assets

3.7.1 SCADA

Aurora has two SCADA systems; a system dating from 1998 in Dunedin, at *DELTA*'s Halsey St office for the control of the Dunedin area, and a Lester Abbey system dating from 2000 in the *DELTA* Cromwell Office for the control of the Central network. All zone substations, except the 1MVA Remarkables substation, have an RTU.

3.7.2 Telecommunication Systems

In the Dunedin area a pilot cable network installed with 33kV cables provides communication with 12 zone substations and Telecom facilities are used for the 6 zone substations not covered by the pilot network.

In the Central area, communication is via a combination of the Aurora owned VHF system in the Upper Clutha area and the Team Talk radio system elsewhere.

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 Control Systems

Dunedin Load Control

Load control 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 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 Control

The majority of load control in the Central area is via a Decabit 317 Hz ripple injection plants, one at each GXP. There are approximately 23,000 Decabit relays on the network that are mainly owned by Electricity Retailers.

Other load control includes two old technologies: a bias system (approximately 70 relays remaining) and a pilot wire system (approximately 2,000 relays). These systems are controlled via interfacing Decabit relays installed at distribution substations.

The Central injection plants are controlled by a custom made system dating from 1996.

3.7.4 Metering Systems

In the Dunedin area, Aurora receives meter pulses from the Transpower GXP metering and also has check meters 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 each GXP. 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 truck-mounted mobile substations, two 500kVA units and one 300kVA unit. Two units are based in Dunedin and one in Cromwell. Aurora does not own any mobile generators but continues to monitor the economics of doing so.

3.8 Asset Details by Category

The value of Aurora's assets by category as derived from the 2005 ODV valuation of the network is presented in Table 3.11, and each category is detailed below.

Asset Category	Quantity	RC	%
Sub-transmission	591 km	$41,437,526	10%
Zone substations	36	$75,446,620	18%
HV distribution	3,002 km	$126,146,640	30%
Distribution switchgear	11,289	$37,174,785	9%
Distribution transformers	5,793	$47,875,000	11%
Distribution substations	5,740	$10,199,000	2%
LV distribution	1,597 km	$68,925,011	16%
Service connections	76,430	$11,265,095	3%
Street lighting distribution	142 km	$4,791,006	1%
System control		$1,611,200	< 1%
Sundry		$562,593	< 1%
Total		**$425,434,475**	**100%**

Table 3.11 - ODV Value of the Aurora Network

The general condition of Aurora's assets is "fit for purpose". The underlying system performance (Section 8) is close to 90 minutes which compares very favourably with the performance of other like networks. Assets that have the potential to give concern, such as the Neville Street cables did for six months in 2004, 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.

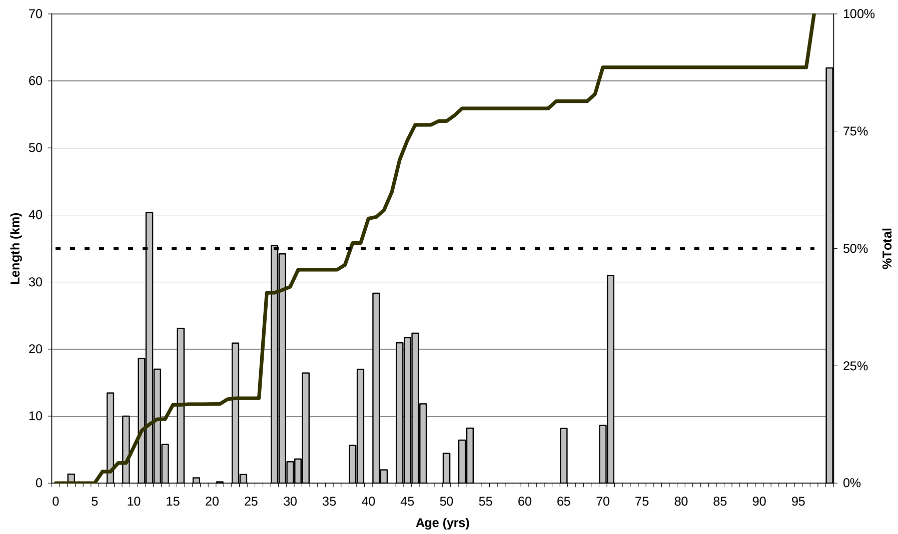

Figure 3.9 – 66 & 33kV Lines Age Profile (Total = 504)

The lines shown at 99 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. 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 coast may have a life of about 30 years, limited by salt corrosion; however, the same line located inland 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.

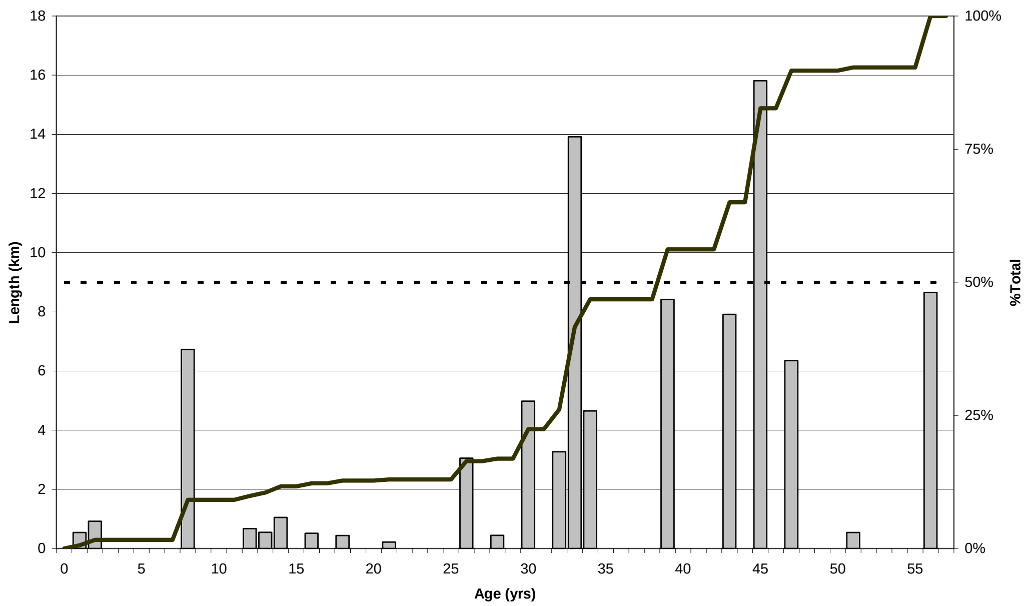

Figure 3.10 – 33kV Cables Age Profile (Total 90 km)

Following the Auckland CBD crisis in 1998, an independent investigation was undertaken to confirm the condition of Aurora's 33kV cables and the maintenance practices employed for those cables. The report confirmed that most of the cables were in good condition. Partial discharge testing of 33kV cables is now used to monitor ongoing condition.

The 33kV gas insulated cables from Halfway Bush GXP point to Neville Street zone substation have experienced leaks. It is proposed to replace these cables within the planning period if it becomes economic to do so.

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 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. The two 70+ year old units at Berwick are scheduled to be replaced with a single 3MVA transformer within the next two years. Subject to economic evaluation, the Ward St transformers are scheduled for replacement later in the planning period in association with a major upgrade of the substation.

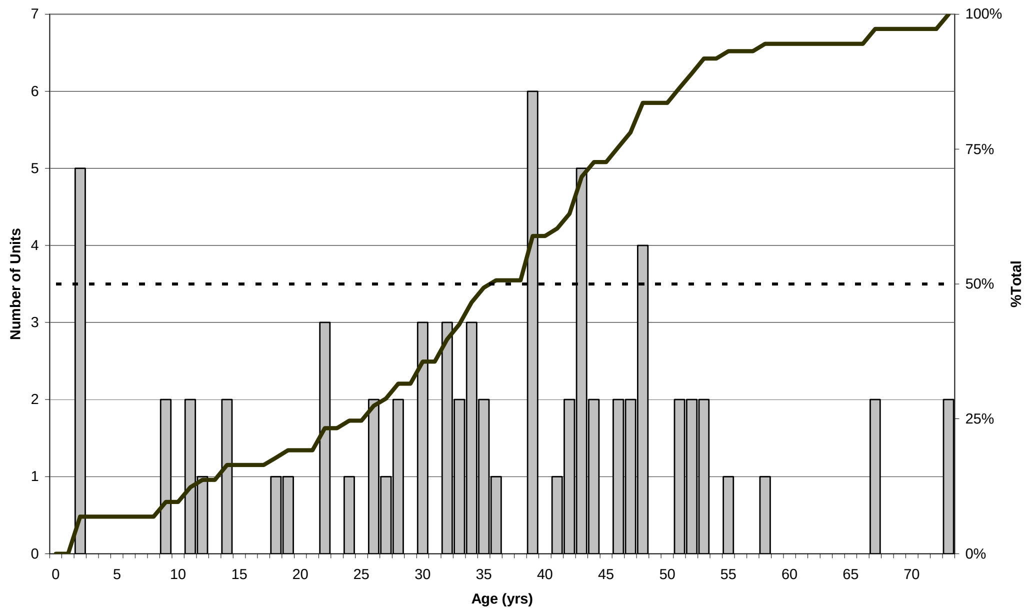

Figure 3.11 – 66 & 33kV Zone Substation Transformers Age Profile (Total = 73)

3.8.4 Zone Substation 66 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, Berwick and Ward Street substations is scheduled during the planning period and the circuit breakers at Alexandra and North East Valley are being closely monitored.

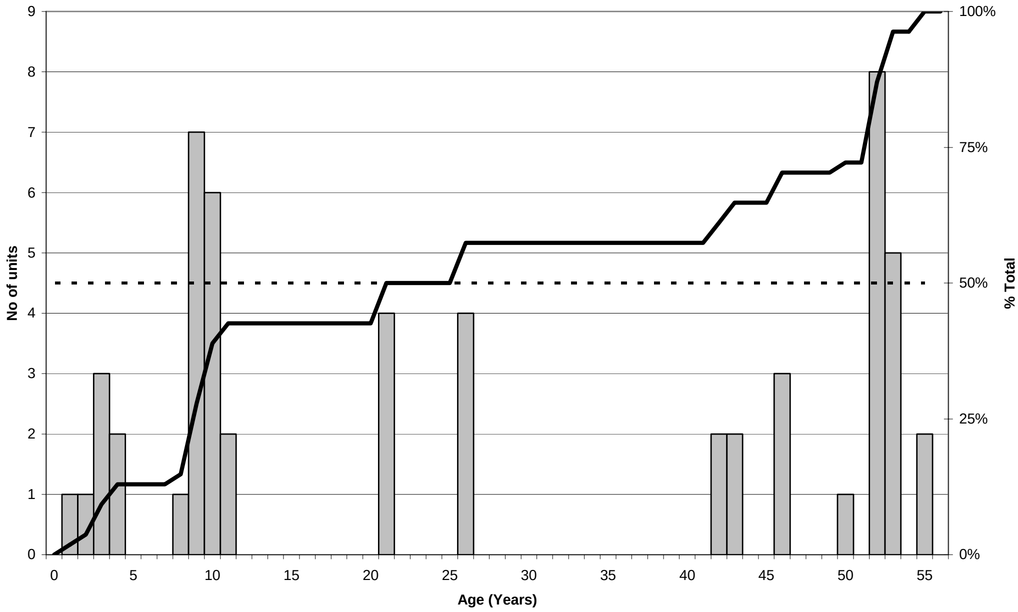

Figure 3.12 – 66 & 33kV Zone Circuit Breakers Age Profile (Total = 51)

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.

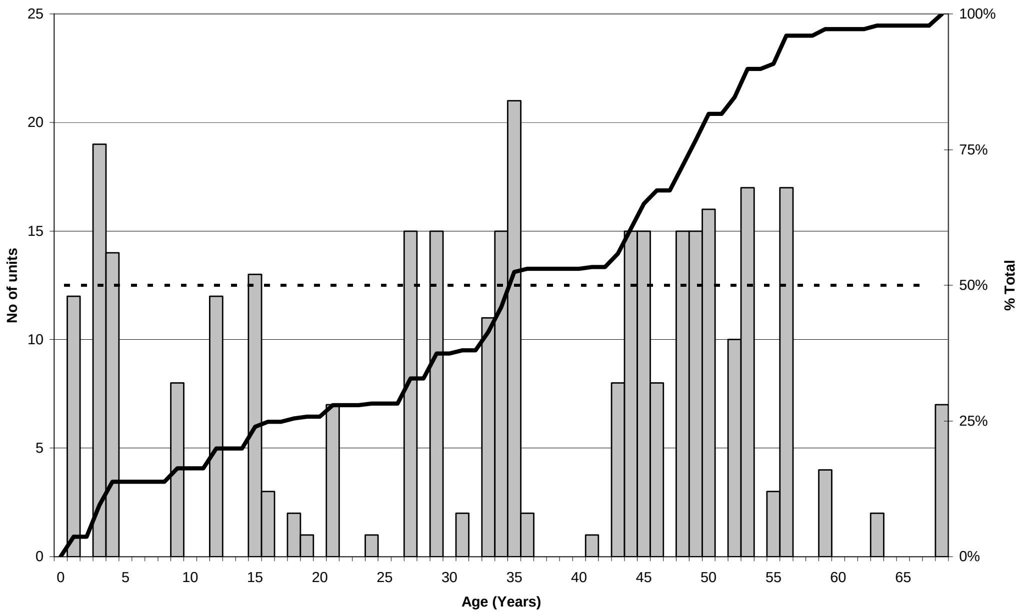

Figure 3.13 – 11 & 6.6kV Circuit Breakers Age Profile (total = 326)

The oldest switchgear is listed in Table 3.12 along with scheduled replacement dates.

Substation	Manufacture Year	Status	Number CBs	Year
Cromwell	1950	Approved underway	9	2005/06
Roxburgh	1950	Planned	1	2007/08
Ward Street	1938	Planned	14	2008/09
Frankton	1950	Planned	8	2007/08
Mosgiel	1954	Planned	10	2008/09
Neville Street	1953	Planned	14	2009/10
Remarkables	1950	Monitor	1	
Halfway Bush	1956	Monitor	16	-
Green Island	1957	Monitor	15	-
Smith Street	1958	Monitor	15	-
Earnscleugh	1960	Monitor	1	-
Dalefield	1960	Monitor	1	
Outram	1963	Monitor	8	

Table 3.12 – Scheduled Zone Substation Switchgear Replacements

3.8.6 Ripple Injection Equipment

In the Dunedin network area, the 11kV and 6.6kV injection plant at each zone substation dates from 1958 or from the date of construction of the substation if later. Replacement of these 17 plants with 33kV injection has been under consideration for some time but is not yet confirmed. The 33kV injection plants in the Central network area are aged 15, 19 and 21 years and replacement is not expected within the planning period.

The age profile of injection plants is shown in Figure 3.14.

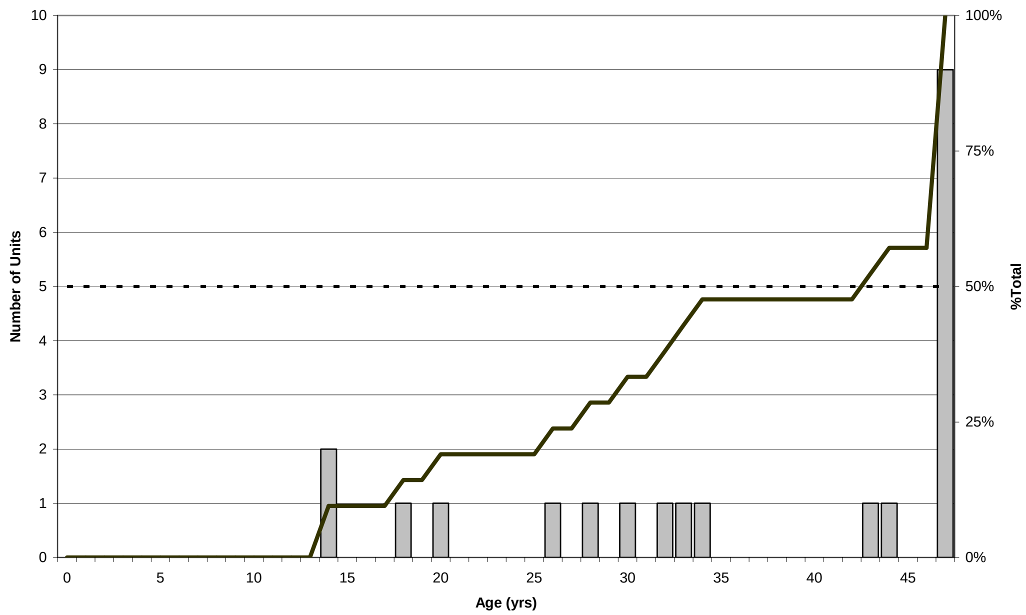

Figure 3.14 – Ripple Injection Equipment Age Profile (Total = 21)

3.8.7 Zone Substation Protection Relays

Aurora does not have specific age profile data for the protection relays but 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.

3.8.8 SCADA Remote Terminal Units

The SCADA remote terminal units in Central date from 2000. In Dunedin the majority of the RTUs were installed in 1988. The 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 and security against intrusion is good. Only routine maintenance is required.

3.8.11 HV Lines

Figure 3.15 details the age profile of HV lines by conductor age. Aurora has 2,362 km of HV lines and the age of 57 km (2%) 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. 16% of lines are aged more than 50 years and no significant change in maintenance expenditure is expected over the planning period as their underlying reliability is good.

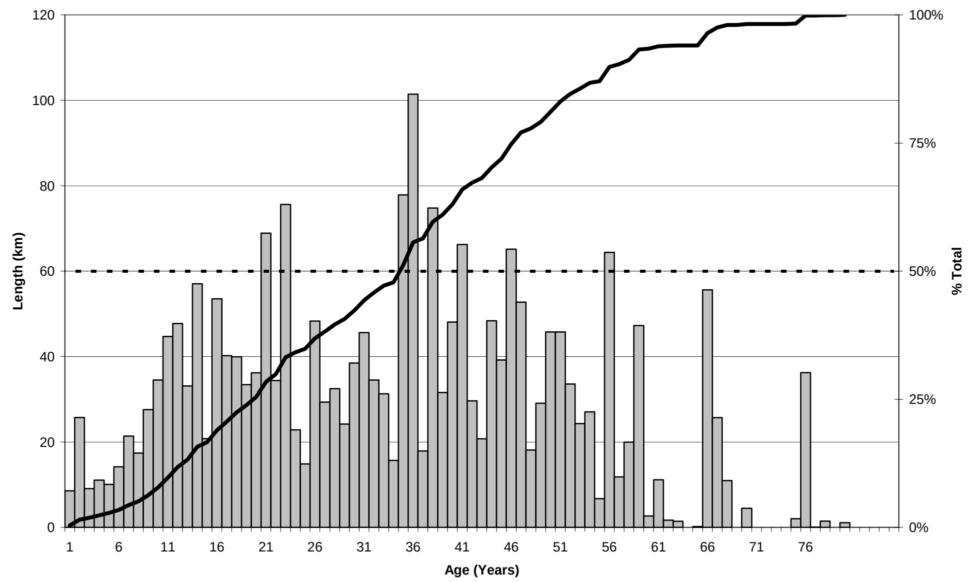

Figure 3.15 – 11 & 6.6kV Lines Age Profile

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3.16. Aurora has 649 km of HV cable and the age of 25 km (4%) 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 and when the need or opportunity arose. 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.

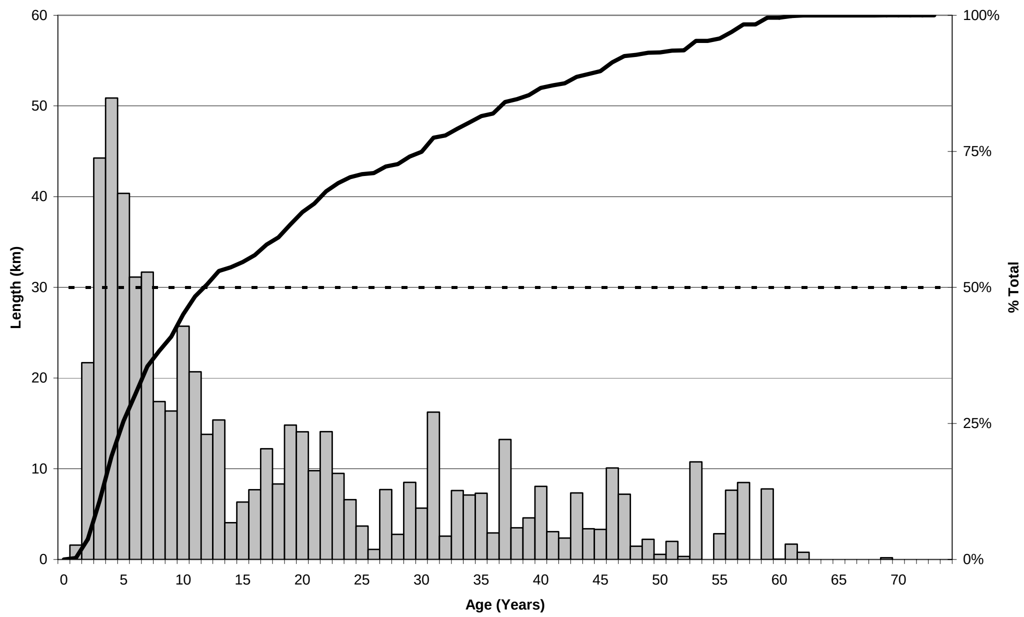

Figure 3.16 – 11 & 6.6kV Cables Age Profile (Total = 624 km)

3.8.13 Distribution Substations

Distribution substations comprise the transformer (which are sub-categorised in the section below), transformer pad, HV and LV fusing and an earth mat. At 1 January 2006, there were 5,894 distribution substations on the Aurora network.

27 pedestal-mounted transformers on the Central network are at risk in the event of a significant earthquake and present a limited safety hazard. They are being replaced at a rate of four to six per year.

In a historically abnormal flash-flood in February 2005, five of the 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 details the age profile of distribution transformers Aurora has in service. The age of only 19 units (0.3%) 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.

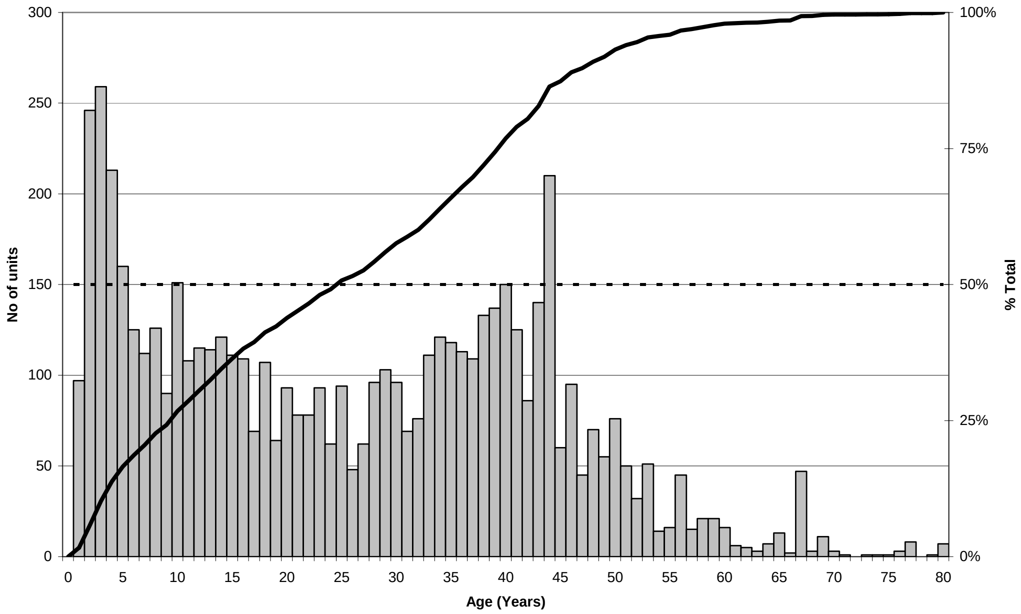

Figure 3.17 – Installed Distribution Transformers Age Profile (Total = 5,903)

3.8.15 HV Regulators

Figure 3.18 details the age profile of regulators. Three units were replaced at Glenorchy in 2005 due to high maintenance costs and poor reliability.

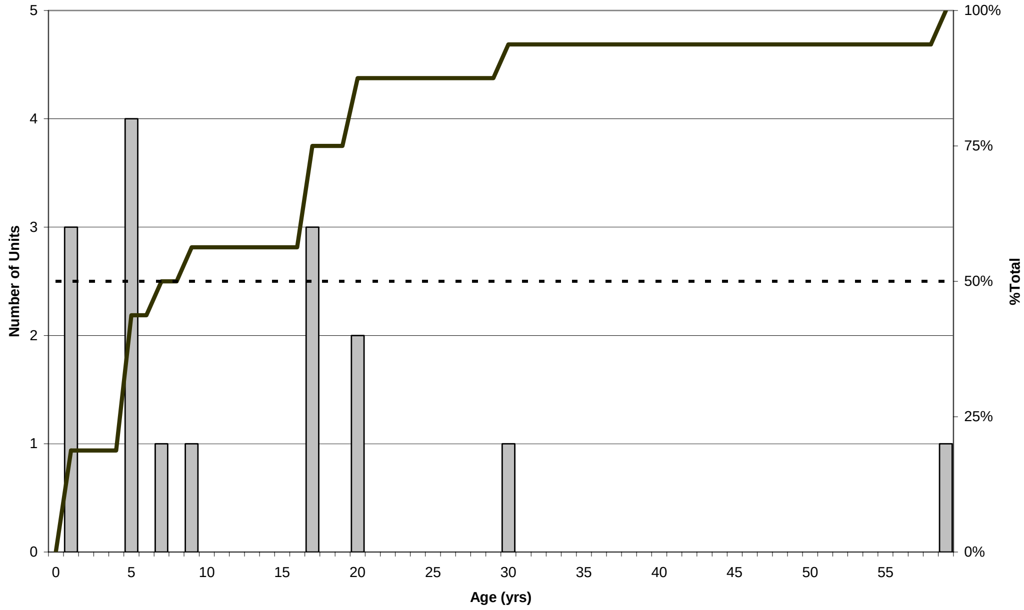

Figure 3.18 – HV Regulators Age Profile (16 Units)

3.8.16 HV Auto-Transformers

Figure 3.9 details the age profile of the 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 of greater than 35 years, they have been reliable and do not require excessive maintenance.

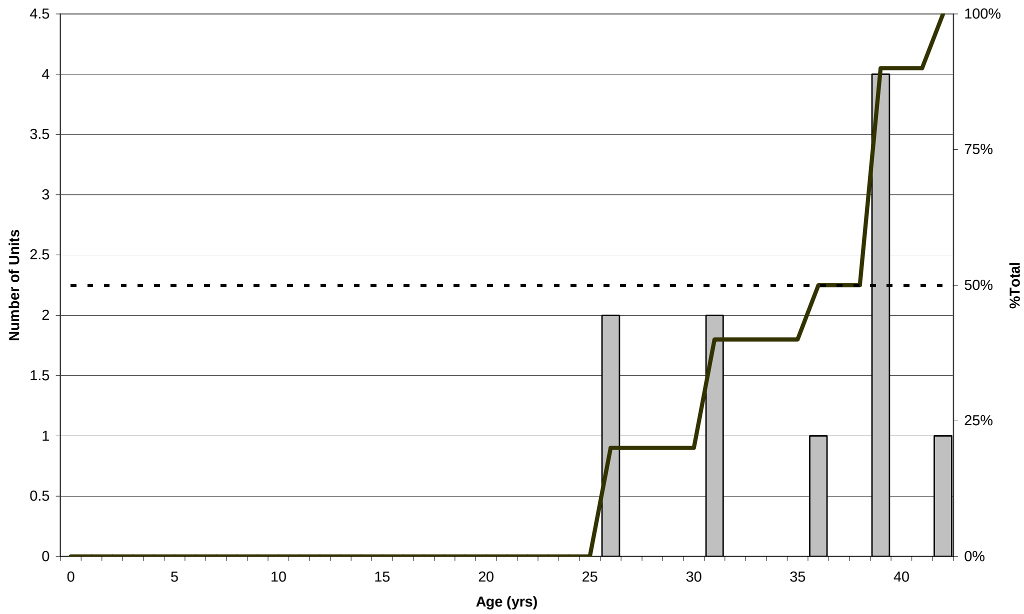

Figure 3.19 – HV Autotransformers Age Profile (10 Units)

3.8.17 HV Distribution Switchgear

The age profile of distribution switchgear is shown in Figure 3.20. Aurora has 2,518 ground-mounted switchgear units but age data is currently only available for 50% (1267) of the units. The switchgear older than 55 years is scheduled to be replaced within the planning period.

Two recent failures of Statter VL switchgear have resulted in plans to replace units at two major consumer sites within two years subject to further investigation.

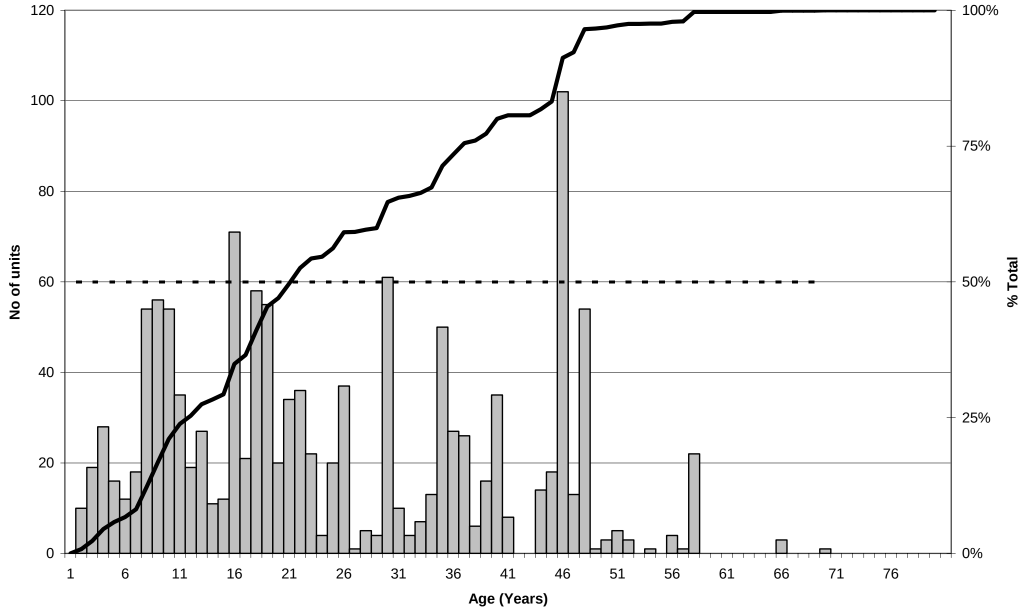

Figure 3.20 – HV Ground Mounted Switchgear Age Profile

3.8.18 LV Overhead Conductor

Figure 3.21 shows the age profile of overhead LV lines. Aurora has 864km of LV line and 143 km (17%) has yet to be confirmed as dating from line construction. There are two types of LV overhead on the network, aerial bundled conductor (ABC – which is rarely used) and open wire on pin insulators.

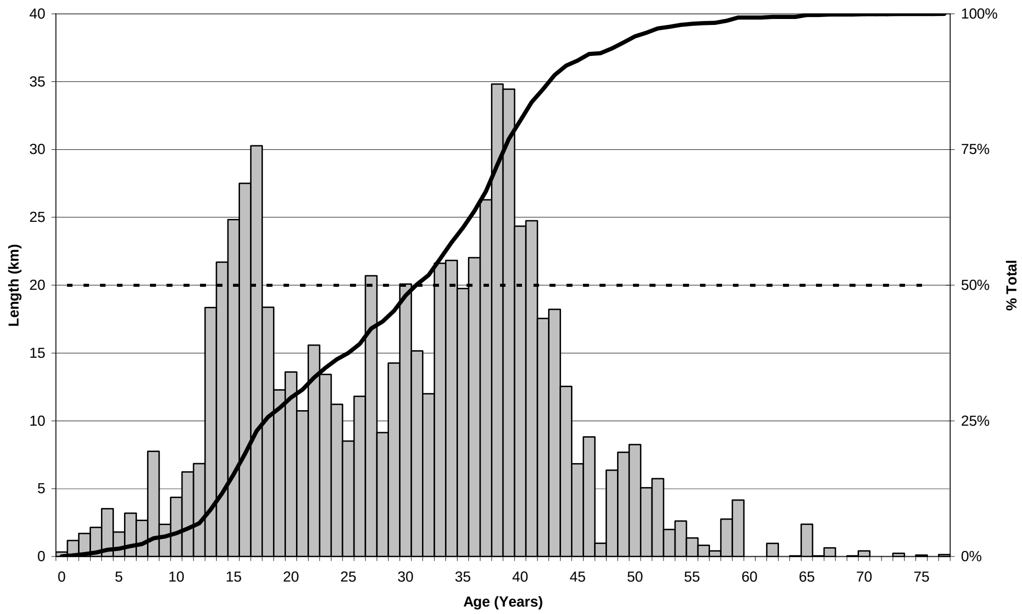

Figure 3.21 – LV Distribution Line Age Profile (Total = 721 km)

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

Part of the "hump" at the 15 year age group is due to "bad data" which is to be corrected.

3.8.19 LV Underground

Figure 3.22 shows the age profile of the underground cable. Aurora has 617 km of LV cable and the age of 67 km (11%) 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 used.

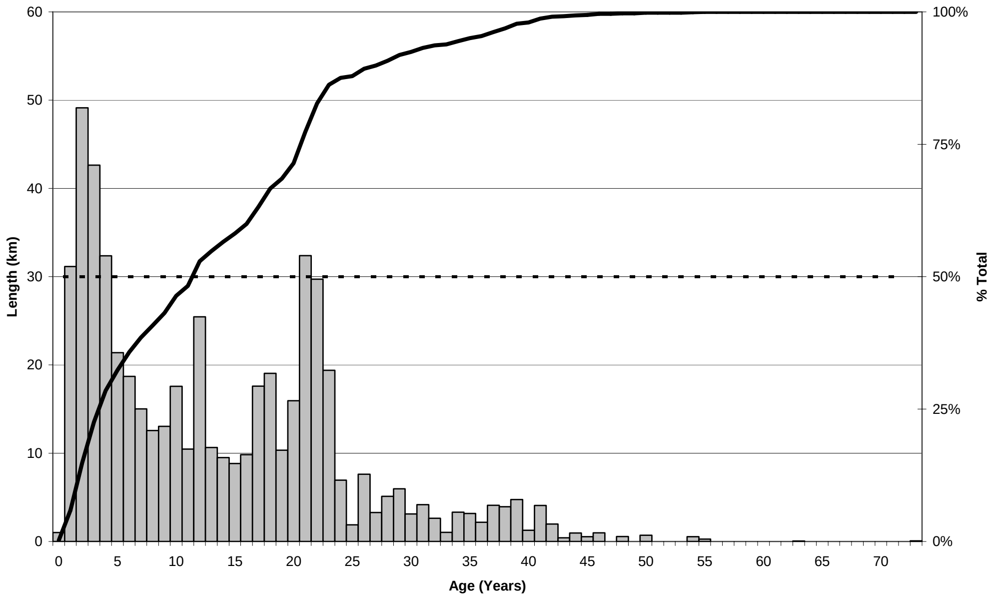

Figure 3.22 – LV Distribution Cable Age Profile (Total = 550 km)

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

Figure 3.23 details the likely age profile of 58,958 poles used for the support of HV and LV circuits. For 40% of this pole population specific pole age is not available and age is "estimated" for construction date and pole condition.

A condition-based inspection regime is in place and there is no evidence of increased replacements being required in 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. Investigation has confirmed that as long as softwood poles are selected based on strict criteria they should have an acceptable life. However recent discussions with other asset owners indicate the need to review softwood pole performance within the planning period.

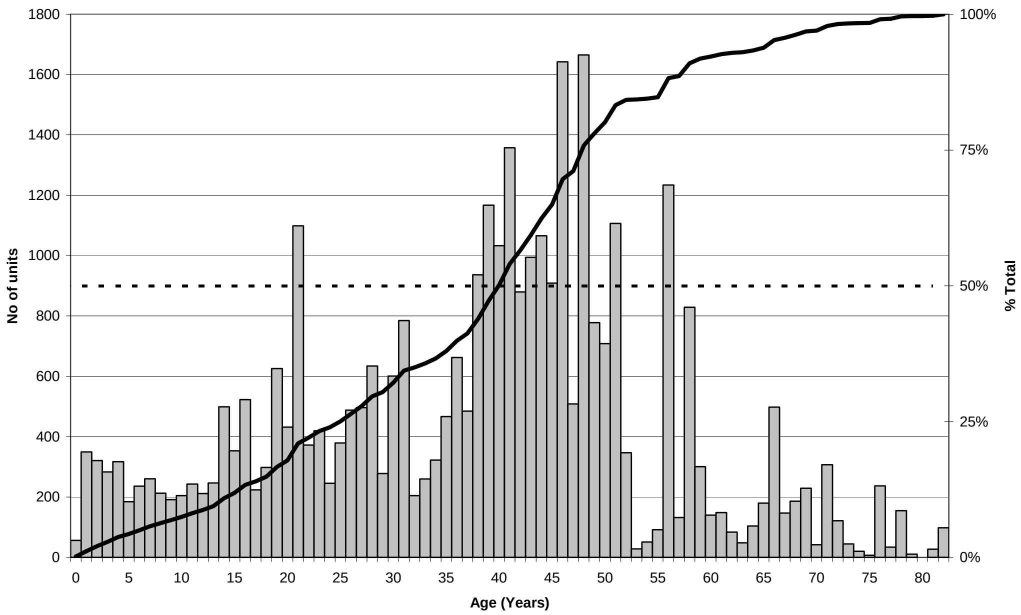

Figure 3.23 – Poles Age Profile

3.8.21 System Control Equipment

The Central region SCADA master station is a Lester Abbey system installed in 2000. The Dunedin master station is a Foxboro system installed in 1998 for which a hardware and software upgrade was completed in March 2006.

3.9 Justification for Assets

All assets are justified by present or anticipated requirements except for approximately 2.1% which have been "optimised" down or out for ODV purposes. Although such assets have been optimised out, many are still required to make the actual network operate or to meet existing network standards (e.g. fault limiting reactors). These assets require ongoing 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.

Assets that were optimised in the 2004 ODV 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 the supply to the 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. The total quantity optimised was 13.5 km in the Central area and 0.73 km in the Dunedin area. 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.

LV Distribution

LV distribution lines and cables that were identified in the GIS as being not in service where optimised out. The total quantity optimised was 3.18 km.

Sub Transmission

Circuit 2 to the South City Substation was optimised out because there are now only two transformers at South City. Ward Street and 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.

Pilots

32.9 km of pilot cables were optimised out in the Dunedin area as they are surplus to modern requirements.

Zone Substation Assets

At Alexandra substation 33kV switches 3106 and 3104 were optimised out as they are for future use. At Wanaka substation the CB and protection associated with the unused feeders 2751 and 2757 were optimised out. At Fernhill substation the 33kV CB 3902 and associated protection for the future supply to Glenorchy was optimised out. The T2 bus section and incoming circuit breakers at South City with associated protection was 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, i.e. 5/10MVA.

One feeder at the Cromwell substation was optimised out.

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. Unused HV feeder circuit breakers (19) were optimised out.

HV feeders in the Dunedin area were optimised out (17) when their projected 5 year load was less than 30% of the feeder rating times 0.67, unless they were providing standby supply for large consumers.

Ward 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 load control injection plant in Dunedin was optimised to injection at 33kV.

4 Service Levels

4.1 Consumer Oriented Performance Targets

4.1.1 Network Performance

Because of the natural trade-off between price and quality, Aurora's network performance should be ultimately determined by consumers' expectations about and willingness to pay for quality. In the interim the drivers outlined below are the parameters by which network performance is presently measured and targeted.

Network performance requirements can be met by different asset management strategies and operational responses including:

- maintenance to maintain or improve the condition of the asset;
- development to install assets in a new configuration;
- enhancements to the existing system or changes to the way in which the assets are operated; and
- improved response times for faults.

Network performance varies significantly from year to year due to the random occurrence of major weather events. Historic performance in terms of minutes without supply per average consumer for the last five years per year is shown in Table 4.1, split into underlying and significant event components. Significant events are defined as those over 300,000 consumer minutes.

Period End 31 March	2001/02	2002/03	2003/04	2004/05	2005/06
Unplanned					
Underlying	61.5	55.7	56.6	67.8	70.8
Significant Events	0	12.9	23.4	5.4	0
Transpower	13.4	12.1	1.0	0.0	13.9
Total Unplanned	**74.9**	**80.7**	**81.0**	**73.2**	**84.7**
Planned					
Underlying	13.8	20.5	16.3	7.3	11.7
Total					
Underlying	75.3	76.2	72.9	75.1	82.5
Significant Events	0	12.9	23.4	5.4	0
Transpower	13.4	12.1	1.0	0.0	13.9
Disclosure Total	**88.7**	**101.2**	**97.3**	**80.5**	**96.4**
Other (LV etc)	0.7	0.8	0.1	0.9	0.5
Overall Total	**89.4**	**101.8**	**97.4**	**81.4**	**96.9**

Table 4.1: Network Performance History (SAIDI) (minutes)

As detailed elsewhere, **the intention is to hold SAIDI constant**, at the levels shown in Table 4.2. Analysis of the reliability data for other distribution networks in New Zealand reveals a present average figure of 151 minutes without supply per consumer per year.

	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Unplanned	75	75	75	75	75	75	75	75	75	75
Planned	15	15	15	15	15	15	15	15	15	15
Total	90	90	90	90	90	90	90	90	90	90

Table 4.2 – Network Performance Target (SAIDI)

Within this strategy analysis will continue to improve worst component 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.

SAIDI is Aurora's primary performance driver. A secondary driver is unplanned SAIFI and the target for this is shown in Table 4.4 below:

	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Unplanned	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**	**1.36**

Table 4.3 – Network Performance Target (SAIFI)

Aurora also has a range of internally set or externally negotiated target levels for service covering the following areas:

4.1.2 Restoration of Electricity Delivery and Service Interruption Investigations

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 (incl 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.

Service failure payments relating to 360 ICPs were made in the year ending 31 March 2006.

Frequency of interruptions following a general network failure

Aurora has the following targets:

(i) urban areas – no more than 4 interruptions per annum

(ii) rural areas – no more than 10 interruptions per annum

(iii) remote rural areas – no more than 20 interruptions per annum.

In the year ending 31 March 2006, 1,637 (2.4%) urban consumers experienced more than four interruptions and 1,690 (16.8%) rural consumers experienced more than 10 interruptions. Most of the rural consumers experiencing high numbers of interruptions are supplied from reclosers and, hence, many of the interruptions will be for relatively short periods.

Power Quality or Service Interruption Investigations

Aurora will respond to enquiries regarding power quality or service interruption investigations with 7 working days. If the investigation cannot be completed within 7 working days, then Aurora will provide within 7 working days an estimate of the time it will take to complete such an investigation. Aurora will remedy any problems under its control in a timely manner, in accordance with good industry practice.

4.2 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and Efficiency of Line Business Activity

From an electricity consumer's perspective, asset performance and efficiency can be measured by availability of supply, detailed in Section 4.1 above.

From a Line Company's perspective, it can be measured in economic terms. Monitoring of the cost of maintenance and for repair of assets, plus the cost of non-supply arising from the failure of assets, and measurement against the replacement cost of those assets, is an integral part of Aurora's asset management practice. Physical asset performance targets, such as faults per 100 km of conductor, are supply side measures and are secondary to SAIFI. Such physical asset performance measures can be found on Aurora's website www.electricity.co.nz within the Information Disclosure material therein.

4.2.1 Voltage Range

A minimum and maximum voltage is set by statutory requirement 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 (e.g. lightning) or unexpected loads and all can require solutions that take time. Voltage excursions will normally be reported by consumers and will normally be for low voltage, due to rising loads or failing conductor joints, and reported 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 and, when alerted to voltage excursions, sets a time target for solution at 31 December each year. These targets are set against good industry practice. The usual impediment to meeting this target is gaining Local Authority agreement as to where to locate equipment such as additional transformers required to improve localised voltage complaints.

4.2.2 Supply Interruption

A thorough discussion of the principles applying to the design for and monitoring of supply reliability in New Zealand appears in the 1993 *Reliability of Electricity Supply*[2] report by the Canterbury University Centre for Advanced Engineering.

Many distribution businesses have adopted the tabular form of security guideline. This is a useful rule-of-thumb approach to network design in pursuit of performance levels expected by users of the assets, but it is dependent on engineers' perceptions of consumers' needs (e.g. larger load groups and "urban" feeders are generally assigned higher standards without the basis of the choice being explicit). Such a deterministic approach was used in the past by Aurora for the Dunedin City area, but has been replaced by a demand-side-driven probabilistic approach. This approach is more sophisticated, is facilitated by technology

[2] *Reliability of Electricity Supply*, Canterbury University Centre for Advanced Engineering, 1993, page 177.

available today and, in Aurora's view, will lead to better asset utilisation and thus lower costs while meeting consumer expectations. Because this process requires user-input, it is described here in some detail.

Step One - Determine What Users Want

User opinion on quality of supply issues is continuously surveyed by Aurora. The survey was commenced in 1999 and is continuous both so that results are less affected by long periods without supply interruption, or by significant interruption, at the time the survey is conducted with a given consumer, and so that the result evolves with changes in network performance. It 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.

Results to date can be summarised as follows:

Aurora's Continuous Price V Quality Survey							
Results to 31 March	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006[3]**
Consumers Surveyed	726	4,123	4,220	4,327	4,554	4,641	4,221
Response Rate	19%	20%	20%	20%	18%	18%	18%
Responses							
Prefer higher quality	9.6%	8.4%	9.3%	9.3%	7.4%	6.7%	5.3%
Prefer lower price	90.4%	91.6%	90.7%	90.7%	92.6%	93.3%	94.7%

Table 4.4 – Price Versus Quality Survey

While the survey strongly implies that quality can be reduced providing a price decrease results, the fact is that quality cannot be altered rapidly, so that both quality changes and consequent price changes will be marginal and relatively invisible to consumers.

As supply quality moves nearer to that required by the majority of consumers, there is increased risk that a minority will receive lesser quality than they wish. Options to provide higher quality for specific needs will be available (and involve additional charges) but will be limited by network topology. However demand-side options (e.g. interruptible load, load storage, on-site generation) will also be available to the consumer at their own investment cost. Conversely there is no case for the majority of consumers paying for higher quality than they require.

Step 2 - Determine the Probability of Interruption

Uninterrupted delivery is only available, if at all, at a cost well above what consumers are generally prepared to pay. Accordingly, design and operating choices must be made not on avoiding interruption but on reducing interruption below a given probability and/or impact.

Determination of fault probability requires maintenance histories and fault histories of network components to be monitored over decades. There is risk that probabilities will be incorrectly assessed internally and accordingly Aurora will use outside expertise to confirm that probability assessments are appropriate.

[3] Provisional results for 2006 based upon responses received to date.

Step 3 - Put a Value on Avoidance of Interruption

Operating and design choices affect network performance and they are available both throughout the network and externally (transmission, embedded generation and interruptible load options). To assist the pricing of non-network options Aurora has adopted a "lost-load" approach to reliability planning, by assigning a dollar value to supply interruptions, presently as follows:

Type of Interruption	Value of kWh Unserved [4]
Unplanned - Residential	$ 4
Unplanned – Other	$40
Planned – Residential	$ 2
Planned – Other	$20
Planned – Average	$ 4

Table 4.5 – Valuation of Interruption

These values are used in assessing the cost of interruptions that result from asset operating and investment choices. Aurora has made these value assumptions *until asset users can agree on a better basis*. In view of the continuous survey preference by consumers for cost reduction over quality improvement, Aurora expects that the above values will be reduced over time, automatically rationing both operating expenditure and capital investment and thus delivering lower costs. This has now happened by default - the above rates have not been increased since they were introduced in 1999, whereas inflation and rising energy prices would otherwise imply an increase.

The decision regarding whether work should be done using live line techniques, or not, is similarly an economic one – the contractor will determine the cheaper cost for their client based on the above values of kWh un-served.

This probabilistic approach can be criticised on the basis that it does not appropriately separate "other" consumers into relevant categories (e.g. rural load, industrial load, etc). However, such separation would be a simple extension, presuming that retailers are willing to provide the necessary categorisation of ICPs and can agree the relative values of interruptions for each category.

Step 4 - Discovering Economic Opportunities

Changes to operating practices or asset investment will occur where the annual cost of these is less than the value of un-served load. This economic hurdle can be determined at any point in the network by multiplying the probability of a fault or of multiple concurrent faults by the value of un-served load that results.

4.2.3 Interruption Targets

Until quality issues have been more widely debated with network users, the measure chosen to monitor overall asset performance is the System Average Interruption Duration Index (SAIDI), since it combines both interruption frequency and interruption duration, and the plan provides to hold it at present levels. Acceptance by users of the standard Use-of-System agreement indicates acceptance of this strategy.

In addition, users have negotiated with Aurora compensation payments where supply interruption exceeds nominated durations. These payments apply to the standard Use-of-System agreement and other arrangements can be negotiated. These arrangements impact on operating and capital expenditure and the plan provides for this.

[4] *Reliability of Electricity Supply*, Canterbury University Centre for Advanced Engineering, 1993, page 111.

The remaining interruption targets required to be disclosed are outcomes rather than expenditure drivers.

4.2.4 Frequency of Interruption

An acceptable overall level of SAIDI can disguise local reliability that is significantly worse than average. For some years Aurora has monitored "FAIDI" (feeder customer-minutes divided by feeder customer number, for each feeder) to ensure that the performance of the worst feeders is apparent. For "problem feeders" consumers are more sensitive to frequency of interruptions, and this is receiving specific attention. Examples of such analysis are shown in Figure 5.3 and Figure 5.4.

4.2.5 Customer Service

Particularly because Aurora has contracted out management of its assets, Aurora ensures appropriate customer service for such matters as answering telephones and correspondence by monitoring *DELTA*'s performance.

4.2.6 Safety Performance

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. Aurora operating and maintenance standards detail the procedures for different situations to meet these principles.

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 sub-transmission and distribution lines through its maintenance programmes by, for example, ensuring that vegetation is maintained clear from lines. Similarly, substation fences and gates and other equipment enclosures are kept in good order.

One report of electric shock in 2003 resulted from poor earthing by a contractor. There have been no other reported instances in recent years.

There have been two instances of fires starting during system faults due to inadequate earthing. Remedial works were undertaken.

4.2.7 Environmental Responsibility Performance

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 usage. A programme to install oil containment bunds around Dunedin zone substation transformers was completed in 1997 and distribution transformer storage areas in 1998. Not all of the Central zone substations have bunding and this is being addressed. 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.

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, in excess of 3% per annum, to continue in the areas served by the Frankton and Cromwell GXPs. This is supported by Statistics New Zealand prediction that the present population in the Queenstown Lakes District Council area could more than double during the next 20 years.

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

Minimal population growth is expected in Dunedin over the next 20 years. Overall growth in electrical demand is expected to average between 0.5% 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 in nominal dollar terms, so that constant amounts represent reducing real-cost expenditure.

	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
New customers	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200
Local growth including renewals	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
System development including SCADA	210	210	220	220	220	230	240	240	240	250
Berwick zone substation	430									
Subtransmission and zone substations	2,170	3,660	3,820	4,280	4,190	5,020	5,410	5,810	6,230	6,510
Undergrounding	2,070	1,770	2,220	2,250	2,280	2,310	2,340	2,370	2,400	2,440
Total	13,960	15,380	15,660	16,150	16,090	16,960	17,380	17,820	18,270	18,600

Table 5.1 – Capital Expenditure Forecast ($000)

- New consumers: developments required to meet the local area demand dictated by new connections.
- Local growth: 11kV development to meet general local area increase in demand and to maintain statutory voltage requirements.
- System development: is defined as minor 33kV subtransmission, zone substations, protection (i.e. SCADA) and special (rare, costly and specifically defined 11kV) projects.
- Undergrounding includes $100,000 of works to other utilities - mainly Telecom.

- The Berwick transformer and 33kV switchgear has reached the end of its economic life and replacement has been approved.
- The Subtransmission and Zone substation provision covers potential projects subject to final economic analysis. Specific projects currently under final investigation are described in Section 5 and include:

  Wakatipu 33kV ring (5.10.2)

  Morven Ferry Road substation (5.11.4)

  Mosgiel zone substation (5.11.5)

  Tarras zone substation (5.11.6)

  Frankton zone substation (5.11.7)

  Commonage zone substation (5.11.9)

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

- Projects that are anticipated to occur in the later half of the planning period are:

  Jack's Point zone substation (5.11.12)

  Ward Street substation upgrade (6.5.3)

  Dunedin ripple injection replacement (6.5.10).

5.2 Distributed Generation Policy

Aurora encourages the connection of distributed generation to its network and has in excess of 40MW of embedded generation. Aurora has investigated the installation of generation to defer transmission upgrades and it is presently considered that most economic method to support the winter peak growth in the Cardrona valley will be by the installation of further diesel generation.

Aurora has guidelines for the connection of small distributed generation published on its website at www.electricity.co.nz. For the connection of larger capacity generation, the New Zealand Electricity Engineers Association's guidelines are followed and application information required is also published on www.electricity.co.nz.

Aurora's Congestion Period Demand (CPD) pricing methodology financially rewards the operation of standby generation plant during network congestion periods. Aurora applies the "Model Principles for the Connection of Distributed Generation to a Network" as published by the MARIA Governance Board on 14 June 2003.

5.3 Non Network Solutions

Demand side management (DSM) provides an alternative to investing in network transmission assets and the primary mechanism for maintaining better utilisation of distribution assets is via our Aurora's delivery pricing structure. In addition, a headworks charge for new connections above 150kVA encourages designers 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 period pricing 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 40MW 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.

5.4 Planning Criteria

Planning decisions within the electrical distribution industry have historically been deterministic and sometimes overly conservative. In the past the "n-1" criterion was applied almost universally at a zone substation and sub-transmission level. Aurora uses the n-1 criteria as a screening tool to identify which parts of its sub-transmission and zone substation network require the application of probabilistic analysis to determine the most economic time to upgrade assets. Probabilistic analysis calculates an annual cost of energy not supplied for the selected network configuration. Upgrades will proceed when the net present value of the energy not supplied is greater than the cost of the upgrade. Table 4.4 refers.

Probabilistic analysis is also applied at the HV feeder level. The trigger for analysis is when it is not possible to fully off-load a feeder onto adjacent feeders at peak load times or the feeder has reached 85% of its thermal rating. On rural feeders, it is normally voltage drop that 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 collects half hourly load data after each winter for all zone substations. The load data for the previous year is analysed to identify upgrading works expected over for the following six years. The development plan also includes projects to improve network reliability and the renewal of aging assets. Budgetary estimates for each project are produced.

There are usually multiple options to resolve most network constraints. Aurora generally selects the option with the lowest life cycle cost, by comparing 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 upgrade paths.

5.6 Load Forecasting Methodology

Load predictions are undertaken annually at HV feeder and zone substation level and are based on past trends and known future developments. When analysing load data, peak loads are checked to ensure they are not the result of a temporary load transfer. Permanent load shifts are also taken into account. Factors that are taken into account include land zoning, population projections and expected economic conditions.

In Dunedin, once every 5 to 10 years there is an extreme cold weather event, typically a three-day snowfall that occurs during the week outside the school holiday period. These events can add an additional 20MW 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 in accordance with Table 5.2.

Priority	Project Category
1	Projects to eliminate significant health and safety issues.
2	Projects to resolve consumer voltage below 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

5.8 Equipment Ratings

Equipment ratings are assigned in accordance with Table 5.3.

Equipment	Rating Allocation
Zone substation transformers ONAN	Transformers are operated to 120% of nominal rating by taking advantage of low ambient temperature during high load periods and cyclic load profile.
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	Manufacture’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.
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 below and are equal to the demand on the GXP plus embedded generation (see Table 5.5 and Figure 5.2).

Calendar Year			Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin
1998	Actual	GXP Off-take + Embedded Generation (MW)	15.3	15.3	30.6	114.6	61.9
1999			15.4	16.5	32.9	114.7	61.3
2000			14.7	17.4	34.6	121.7	62.4
2001			15.0	21.1	38.0	124.7	61.7
2002			17.1	19.9	37.4	**133.0**	65.9
2003			15.2	20.2	38.3	116.4	61.2
2004			15.6	21.5	**41.4**	124.0	**67.0**
2005			**17.2**	**24.4**	40.4	126.0	66.1
2006	Predicted		17.5	25.5	41.8	127.2	66.8
2007			17.7	26.6	43.2	128.5	67.4
2008			18.0	27.7	44.6	129.7	68.1
2009			18.2	28.8	46.0	131.0	68.8
2010			18.5	29.9	47.4	132.2	69.4
2011			18.7	31.1	48.8	133.5	70.1
2012			19.0	32.2	50.2	134.8	70.7
Past growth rate (trend 1998 to 2005)			1.1%	4.4%	3.5%	0.7%	0.7%
Growth rate for planning (see 3.1)			1.5%	4.5%	3.5%	1.0%	1.0%

Calendar Year	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin
2005 MW off-take peak (excludes embedded generation)	7.5	21.1	40.2	111.9	66.1
Off take n-1 capacity (continuous) MVA	27	35	33	100	81
Off take n-1 capacity (24 hr winter post contingency) MVA	27	35	41	112	81
Embedded generation (2005 MW at time of off take peak)	1.6	3.3	1.6	3.9	0
Embedded generation (2005 MW at time of system peak)	16.3	3.3	1.6	19.9	0

Table 5.5 – GXP Area Peak Demands

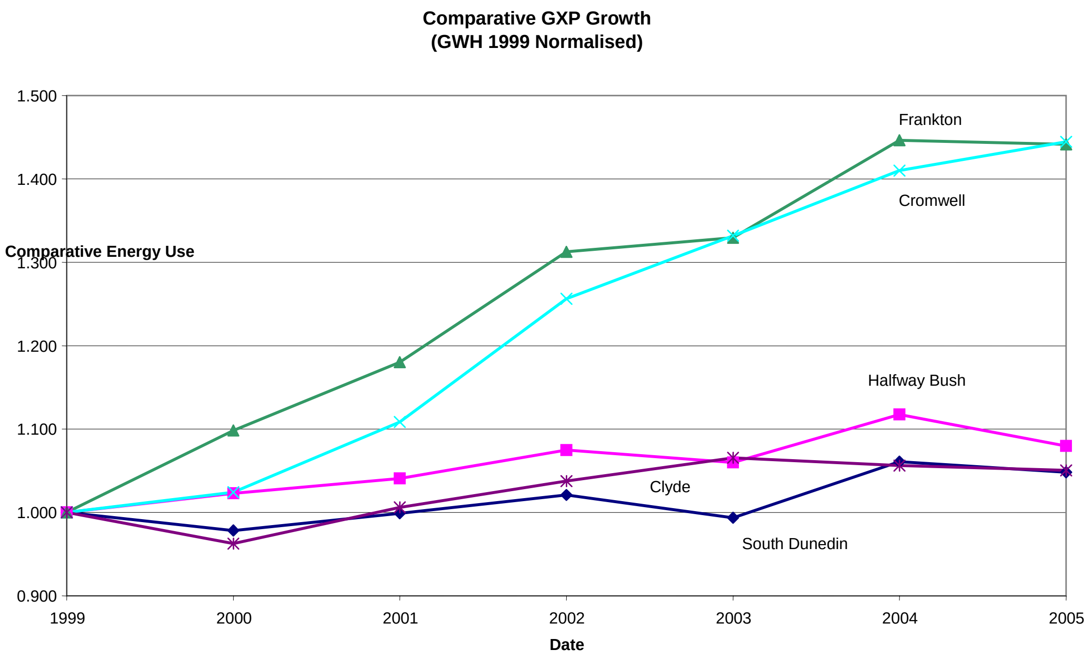

Figure 5.1 – Comparative Growth in GXP Energy (Includes Embedded Generation)

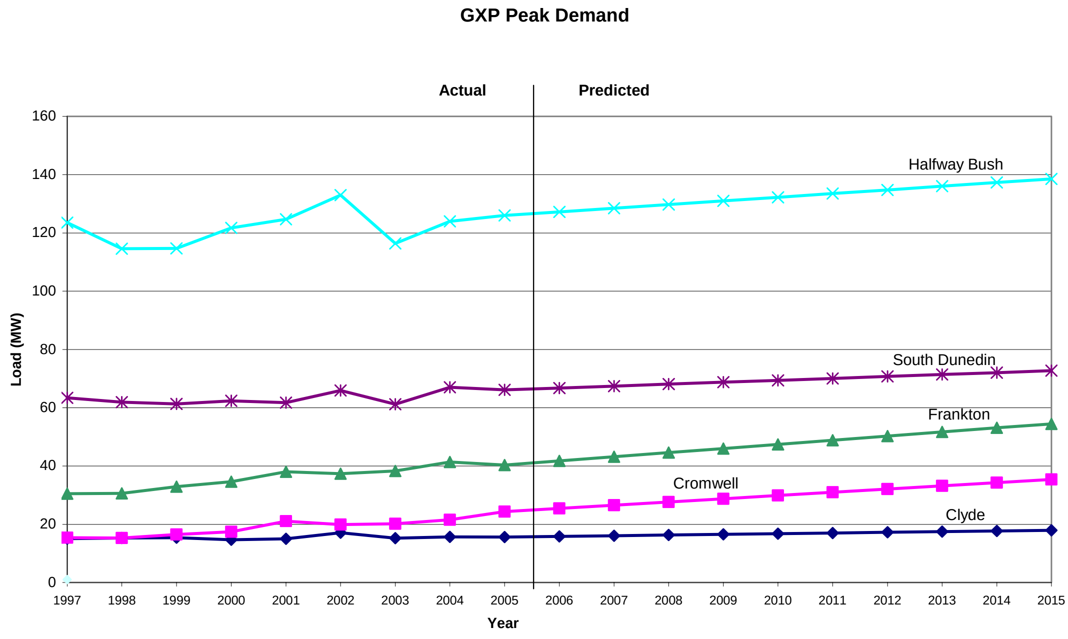

Figure 5.2 – GXP Peak Demands (Includes Embedded Generation)

In commenting to the graphs specifically, the reduction of demand in Dunedin and Clyde 2003 was due to the government's energy savings campaign. The Dunedin 2002 peaks were due to an uncharacteristic 3 day snow fall in May.

Strong growth is predicted to continue in the Frankton and Cromwell GXP areas and more modest growth in the Clyde and Dunedin GXP areas.

5.9.2 Frankton GXP

On June 2005, Transpower has allocated a 24 hour post-contingency rating of 41MVA to their Frankton 110/33kV transformers. The 2005 peak load on the Frankton GXP was 40.2MW (41.02MVA @ 0.98 power factor excluding embedded generation). If the demand on the Frankton GXP exceeds 41MVA at any time, then, under the Electricity Governance System Operator policy rules, Aurora will be required to reduce load below 41MVA.

Since July 2005, Aurora has been negotiating a new investment agreement with Transpower to upgrade the transformers to 80MVA units. It is desirable the upgrade be completed for the winter of 2007 but delays in finalising an agreement with Transpower are making it likely the upgrade will not be completed until 2008. In conjunction with the transformer upgrade, two new 33kV outlets have been requested.

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.

5.9.3 Cromwell GXP

The Cromwell GXP “tees off” the Transpower 220kV lines that run between Twizel and Clyde. Two 220/110/33kV transformers supply the 33kV to the Cromwell GXP and 110kV to the Frankton GXP. The transformers are rated as 85/50/35MVA for their windings respectively. These transformers are allocated a post contingency 220kVA rating of 70MVA by Transpower due to protection constraints and Transpower has indicated that up to $300,000 of work will be required to eliminate this constraint. The 2005 combined Cromwell and Frankton demand was approximately 65MVA. If the combined load continues to grow at 3.8% per annum the 70MVA limit will be exceeded during the winter of 2009.

It is anticipated that it will be 2011 before the Frankton 110kV load reaches 50MVA and 2015 before the 33kV loading reaches 35MVA, so that the upgrade of the Cromwell transformers will be driven by the Frankton 110kV load. The most likely upgrade option is to parallel the existing transformers on one circuit and install a new 220/110/33kV transformer on the other circuit.

5.9.4 Clyde GXP

The Clyde GXP has two 27MVA transformers. The embedded generation on this GXP almost meets the total demand on GXP. Should the embedded generation fail the maximum demand on the GXP would be approximately 17MVA, based on 2005 loadings. There is adequate GXP capacity at Clyde for the foreseeable future.

5.9.5 Halfway Bush GXP

The 2005 peak demand on the Halfway Bush (HWB) GXP exceeded its firm n-1 capacity by 11.9MW due to Waipori generation only injecting 3.9MW of its 44MVA capacity into the 33kV network at this time. Long term it is planned to move the Neville Street substation load to the South Dunedin GXP when the Neville Street gas cables require replacement, (See Sections 5.9.6 and 5.15.1), reducing demand on HWB by approximately 13MVA. In the short term, should the Transpower 100MVA transformer at HWB fail, TrustPower would be asked to increase 33kV generation up to 44MW during peak periods, and up to 5MW would be transferred to the South Dunedin GXP via the 6.6kV network.

5.9.6 South Dunedin GXP

The South Dunedin GXP presently has two 100MVA transformers which have been assigned an 81MVA limit by Transpower due to metering accuracy limitations. The present peak demand on South Dunedin is 66MVA but would be very close to 81MVA if the Neville Street substation load is transferred to South Dunedin. The work required to eliminate the constraint is to change the metering CT ratio from 1200/1 to 2400/1 and re-calibrate the meters, at an estimated cost of $10,000.

5.10 Subtransmission

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

5.10.1 Frankton to Queenstown

The n-1 capacity of the 33kV sub-transmission from the Frankton GXP to Queenstown is constrained by the 33kV cables into the Queenstown substation. Two options to resolve this constraint are to upgrade the 33kV cables or install a new substation in the Commonage area on Queenstown Hill upstream of the cables. The new Commonage substation is presently the preferred solution as shown in Section 5.11.7 below.

5.10.2 Cardrona Valley

Load in the Cardrona valley is increasing due to the expansion of the Cardrona ski field and subdivision activity in the area. In 2001 two voltage regulators were installed on the line. These regulators can support a maximum load of 2MVA in the valley. The present maximum load in the valley is 1.5MVA. The Cardrona Ski field has been given consent to install an additional 100kVA of capacity for the 2006 ski season which will result in the circuit running near to its maximum capacity. The loading on the circuit will continue to be monitored closely.

Investigations into the options for upgrading the Cardrona supply have been carried out. The two main options are to construct a 33kV line to Cardrona from Wanaka or install diesel generation at Cardrona. Preliminary analysis indicates that the installation of diesel generation could be the most economical solution for additional load up to 1.5MVA (3.5MVA total).

5.10.3 Wanaka to Hawea

Contact Energy proposes to install 16MW of generation at Lake Hawea but has yet to obtain resource consent. If this project proceeds, a 33kV line will be needed from Maungawera to Hawea (6 km) and the existing 33kV cable and line between Wanaka and Maungawera will require upgrading. It is proposed that the new line follows the route of the existing 11kV line in a 33kV over 11kV configuration. Contact's preliminary timetable, which requires confirmation, is to begin commissioning by January 2009. Resource and land owner consent will be required for this project. The estimated cost is $1,008,000.

5.10.4 Nevis Power Scheme

Pioneer Generation is investigating installing a 40MW hydro generation station on the Nevis River and has enquired about options for connection to the Aurora network. The Aurora network requires upgrading. Indicative costs have been given to Pioneer which also has the option of connecting to the nearby Transpower 110kV lines.

5.10.5 Other Major Projects

Other major developments have been proposed 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 the information presented on the table.

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 6MVA 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 is 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 and these act as a “flag” for closer study.

N-1 security is usually not economic for zone substations with a capacity of 3MVA or less. Spare transformers are held that provide cover for several such substations.

When the new proposed Commonage, Morven Ferry and Tarras substations are commissioned there will be a reduction in load of adjacent substations. This is taken into account in future demand predictions as shown in the Table.

Smith Street and South City

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

Mosgiel and East Taieri

The previous load growth rate is only based on the last 3 years, due to load transfer between these substations occurring prior to the 2003 winter.

North City

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

Cromwell

The firm load and n-1 capacity is allocated assuming the switchgear upgrade project that is underway has been completed.

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 sub-transmission system.

				Historical Demands MVA								Predicted Future Demands MVA											
Zone Substation	**Transformer MVA**	**Firm Load MVA**	**n-1**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**Previous Growth %/yr**	**Predicted Growth %/yr**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2015 U.F. Firm**	**2015 UF (n-1)**
Alexandra	7.5/15+7.5/15	15	15	10	10.8	11.1	10	10.4	10.8	0.4%	1.0%	10.9	11.0	11.1	11.2	11.4	11.5	11.6	11.7	11.8	11.9	80%	80%
Anderson's Bay	15 + 15	18	18	14	15.8	15.5	13.5	15.3	14.6	-0.1%	0.5%	14.7	14.7	14.8	14.9	15.0	15.0	15.1	15.2	15.3	15.3	85%	85%
Arrowtown	5 + 5	7.5	6	5.6	6	5.6	6.3	6.3	6.4	2.5%	3.0%	6.6	6.8	7.0	7.2	6.2	6.4	6.6	6.8	7.0	7.2	96%	**120%**
Berwick	0.9 +0.9	2	0	1.2	0.9	1.2	1.2	1.1	1.1	0.8%	1.0%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	63%	**N/A**
Clyde/Earnscleugh	4 +2	4.8	4	4.2	4.1	4.7	4.1	3.6	3.6	-3.8%	2.0%	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.4	92%	**111%**
Coronet Peak	5	6	0	*	*	*	*	3.0	4.4	N/A	3.0%	4.5	4.7	4.8	5.0	5.1	5.3	5.4	5.6	5.7	5.9	99%	**N/A**
Corstorphine	12/24 + 12/24	23	23	12	13	13.5	12.2	13.1	12.5	0.4%	1.0%	12.6	12.8	12.9	13.0	13.2	13.3	13.4	13.6	13.7	13.8	60%	60%
Cromwell	5/10 + 7.5	9.0	9.0	6	6.2	6	6.6	7.1	6.8	3.0%	3.0%	7.0	7.2	7.4	7.6	7.8	8.1	8.3	8.6	8.8	9.1	**101%**	**101%**
Dalefield	3	3.6	0	3.4	3	3	3	1.4	1.9	N/A	2.5%	1.9	2.0	2.0	2.1	2.1	2.2	2.3	2.3	2.4	2.4	68%	**N/A**
Earnscleugh	2			Used to increase Clyde/Earnscleugh firm capacity to 4.8MVA																			
East Taieri	12/24 + 12/24	19	Note 1	10.9	13.4	14.7	13.6	14.2	14.9	4.4%	3.0%	15.4	15.8	16.3	16.8	17.3	17.8	18.3	18.9	19.5	20.0	**105%**	
Ettrick	3	3.6	0	1.8	1.6	2	2	1.8	2.0	2.0%	1.0%	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2	60%	**N/A**
Frankton	7.5/15 +7.5/10	12	10	6.6	7.7	7.9	7.8	8.0	9.0	4.1%	4.0%	9.4	9.7	10.1	10.5	10.9	11.4	11.8	12.3	12.8	13.3	**111%**	**133%**
Fernhill	7.5/10+7.5/10	10	10	4.6	5.1	4.8	5.2	5.2	5.4	2.4%	2.5%	5.5	5.6	5.8	5.9	6.1	6.2	6.4	6.5	6.7	6.9	69%	**N/A**
Green Island	15 + 15	18	18	12	13	12.5	12.9	13.6	13.8	2.3%	1.0%	13.9	14.1	14.2	14.4	14.5	14.7	14.8	15.0	15.1	15.3	85%	85%
Halfway Bush	15 + 15	18	18	12	14	14.1	12.2	12.3	13.1	-0.3%	0.5%	13.2	13.2	13.3	13.4	13.4	13.5	13.6	13.6	13.7	13.8	76%	76%
Kaikorai Val.	12/24 + 12/24	23	22	9	11.8	9	9	10.0	11.9	2.2%	1.0%	12.0	12.1	12.3	12.4	12.5	12.6	12.8	12.9	13.0	13.1	57%	60%
Maungawera	3	3.6	0	2.1	1.9	2.3	1.9	2.2	2.3	2.0%	3.0%	2.4	2.5	2.5	2.6	2.7	2.8	2.9	2.9	3.0	3.1	87%	**N/A**
Mosgiel	10 + 10	13	12	15	14	12	11	11.6	11.8	3.4%	3.0%	12.2	12.5	12.9	13.3	13.7	14.1	14.5	15.0	15.4	15.9	**122%**	**132%**
Neville St	15 + 15	18	18	12.4	14.2	13.6	13	13.6	13.9	1.0%	0.5%	13.9	14.0	14.1	14.2	14.2	14.3	14.4	14.4	14.5	14.6	81%	81%
North City	14/28 +14/28	28	28	19.4	21	21.1	21.1	20.4	19.8	0.0%	1.0%	20.0	20.2	20.4	20.6	20.8	21.0	21.2	21.4	21.7	21.9	78%	78%
North East Val.	9/18 +12/18	23.9	18	11.3	11.3	11.4	10.2	11.4	10.8	-0.9%	0.5%	10.9	10.9	11.0	11.0	11.1	11.2	11.2	11.3	11.3	11.4	48%	63%
Omakau	3	3.6	0	1.1	1.6	1.54	1.7	1.5	1.6	4.2%	3.0%	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.1	59%	**N/A**
Outram	3 + 3	5.6	3.6	2.3	3	2.5	2.5	2.6	2.6	0.4%	0.5%	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	49%	76%
Port Chalmers	7.7 +7.5	11.4	9	7	8	7.5	7.6	7.9	8.1	1.9%	2.0%	8.3	8.5	8.6	8.8	9.0	9.2	9.3	9.5	9.7	9.9	87%	**110%**
Queensberry	3	3.6	0	0.5	0.5	0.6	0.8	1.4	1.6	15.8%	6.0%	1.7	1.8	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	59%	**N/A**
Queenstown	10/20 +10/20	20	20	16.7	18.8	18.3	18	20.4	18.3	2.0%	4.0%	19.1	19.8	12.6	13.1	13.7	14.2	14.8	15.4	16.0	16.6	83%	83%
Remarkables	1	1.2	0	0.7	0.8	0.8	0.8	0.8	0.7	0.6%	1.0%	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	66%	**N/A**
Roxburgh	1.5 +1.5	3.6	1.8	2.6	2.4	2.9	1.9	1.7	2.3	-5.9%	0.5%	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	67%	**133%**
Smith St	15 + 15	18	18	16.8	18.2	19	16	18.1	18.1	0.5%	1.0%	16.8	17.0	17.1	17.3	17.5	17.6	17.8	18.0	18.2	18.4	**102%**	**102%**
South City	9/18 +9/18	24	18	12	13	13	11.8	13.6	14.3	2.4%	1.0%	16.0	16.1	16.3	16.5	16.6	16.8	17.0	17.1	17.3	17.5	73%	97%
St Kilda	12/24 + 12/24	29	23	15	15	14.7	14.7	15.1	15.2	0.3%	0.5%	15.3	15.4	15.4	15.5	15.6	15.7	15.8	15.8	15.9	16.0	55%	70%
Wanaka	12/24 +12/24	25	23	10.6	11.9	11.4	11.5	13.6	14.6	4.9%	5%	15.3	15.9	16.7	17.4	18.2	19.0	19.9	20.8	21.7	22.7	91%	99%
Ward St	15 + 15	23	18	11.8	11.6	11	10.4	10.9	10.6	-2.3%	0.0%	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	46%	59%
Willowbank	15 + 15	18	18	13	14	12.2	12.1	13.7	13.7	0.5%	1.0%	13.8	13.9	14.1	14.2	14.4	14.5	14.7	14.8	15.0	15.1	84%	84%
Commonage	7.5/15+7.5/15	15	15								4.0%			8.0	8.3	8.7	9.0	9.4	9.7	10.1	10.5	70%	
Morven Ferry	5	6	0							0.0%	3.0%					1.2	1.2	1.3	1.3	1.4	1.4	21%	NA
Tarras	3	3.6	0							0.0%	6.0%			0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.8	17%	NA
Jacks Point	7.5/10	10	0							0.0%				1.3	1.8	2.2	2.7	3.1	3.6	4.0	4.5	22%	NA

Table 5.6 – Zone Substation Historical and Predicted Demands

5.11.2 Morven Ferry Substation

A 3 or 5MVA substation is proposed near the junction of Morven Ferry Road and SH6 to relieve the loading on the Arrowtown substation and to support the growth in the Gibbston valley. The estimated cost is $600,000.

5.11.3 Mosgiel Substation

Mosgiel substation is predicted to reach its firm capacity of 13MVA in 2010 and it is proposed to install a third transformer at Mosgiel at this time. It is also planned to replace the 11kV switchgear at the Mosgiel substation in 2008 at an estimated cost of $300,000.

5.11.4 Tarras Substation

The Tarras, Bendigo and Pisa areas are supplied from the 66/11kV 3MVA Queensberry substation. There is no spare 66/11kV transformer available in the event of the Queensberry unit failing so generation would have to be provided for this eventuality. Analysis has shown that this is not economic.

The peak load on Queensberry increased to 1.6MVA between 2003 and 2005 and it is now considered that a substation is justified in the Tarras area at an estimated cost of $850,000.

There has been significant growth in irrigation load in the area and consequent reinforcement works are being designed (an 11kV line along Maori Point Road).

Subject to continued load growth, it is proposed to install a 66/11kV 3 or 5MVA substations at Tarras within the next three years and at Pisa later in the planning period.

5.11.5 Frankton Substation

It is not expected that the Frankton substation will reach its firm load until 2011 but it is intended to upgrade the switchgear configuration before this. The new configuration requires two additional Transpower 33kV outlets and the installation of a 33kV cable from the Transpower GXP to the Aurora substation. The Transpower 33kV outlets will be installed in conjunction with the upgrade of the Frankton GXP transformer, see Section 5.9.2. In conjunction with the 33kV reconfiguration, it is proposed to replace the outdoor 11kV switchgear with new indoor switchgear. The age and condition of the 11kV switchgear is such that the probability of a failure justifies its replacement. .

5.11.6 Queenstown Substation

Without the proposed new Commonage substation, the Queenstown substation would be expected to reach its firm capacity during the winter of 2011. The proposed Commonage substation defers any augmentation beyond the planning period.

5.11.7 Commonage Substation

It is proposed to build a new substation in the Commonage area on Queenstown Hill consisting of two 15MVA transformers. This substation will alleviate the present Queenstown sub-transmission constraint, reduce load on the Queenstown substation and improve the ability to off-load HV feeders in the area. Aurora owns land in the Commonage area which is for a substation. Alternative sites are being assessed to determine if they will be more economic. To connect the new substation into the existing HV network, new cabling and switchgear is required. The cost estimate is $2,500,000.

5.11.8 Hawea Substation

A developer has proposed a 460 lot subdivision adjacent to the present Hawea Township. As the Hawea load increases, it is proposed to install a 33/11kV zone substation close to Hawea. The Maungawera substation may be retained so that the Maungawera and Hawea substations can back each other up when one is being maintained. Aurora has an easement in the Grayburn subdivision for a substation. An alternative location is on Contact Energy land associated with their Hawea generation project (refer 5.10.3). It is envisaged the new Hawea substation would utilise the proposed 33kV line to Hawea for the Contact Energy generation. The cost estimate is $480,000.

5.11.9 Jack’s Point Substation

Significant developments are underway in the Jacks Point area and will be initially supplied from Frankton feeder 703 up to a load of approximately 2MVA. When this load limit is reached, a 33/11kV substation will be built in the development and will be supplied from the 33kV line to Wye Creek. The substation will be designed to eventually accommodate two 5/10MVA transformers. The initial installation will be a single 5/10MVA transformer. Timing depends on the uptake of subdivision lots. The cost estimate is $1,000,000.

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 ± 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 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:	2001	2002	2003	2004	2005	2006
Utilisation:	35.7%	36.2%	36.7%	32.5%	34.2%	33.6%

Table 5.7 – Distribution Transformer Utilisation

Overall utilisation is above the 30% ODV optimisation threshold but appears to be declining. This reduction in utilisation is due to the installed transformer capacity growing faster than the system peak demand. This is attributed to several factors that are listed below:

(1) Subdivisions having transformers designed for a fully occupied subdivision but can take several years for all lots to be connected.

(2) An increase in the establishment of rural subdivisions with many smaller transformers e.g. the typical utilisation of a 15kVA transformer is only 20%.

(3) New large consumers choosing a connection capacity in excess of their needs.

(4) Transformers in subdivisions being oversized.

(5) Consumers adopting Congestion Period Demand (CPD) reduction measures.

(6) Reduction in consumer loads, e.g. use of building changes from a factory to a warehouse.

(7) Larger diversity between loads e.g. the installation of transformers to supply summer irrigation pumps increases the installed transformer capacity without increasing the peak demand.

The following measures have been introduced to improve utilisation:

(1) The introduction of headworks charges has improved the incentives for designers to minimise connection capacity.

(2) New criteria were introduced into subdivision design standards in 2004 for the sizing of transformers.

(3) Higher transformer loads than name-plate capacities are now allowed before upgrading a transformer.

(4) Opportunities to downsize under-utilised transformers are taken when it is economic to do so.

5.14 Reliability and Risk Mitigation Projects

Reliability-initiated projects that will economically reduce the number or duration of consumer outages are not detailed in this plan as those currently being considered are small scale projects less than $300,000 in value.

5.14.1 HV Feeder Performance

Set out in Figure 5.3 is data on outages per HV feeder plotted against circuit length. All things being equal, feeders of similar length would be expected to suffer similar numbers of faults. OM679 and OM669 had a high number of faults in 2005 but most of them resulted in a successful reclose.

Figure 5.4 shows customer outage minutes per HV feeder revealing which feeders made the largest contribution to the total system outage minutes for the network. MA260 (Maungawera zone substation) and QT5202 (Glenorchy feeder) were the worst performers during 2005. Additional reclosers are now proposed for Maungawera. There were a large number of outages on the Glenorchy feeder in 2005 due to problems with the Glenorchy voltage regulators; these have now been replaced and an auto recloser installed on the edge of the Glenorchy township, which should improve performance.

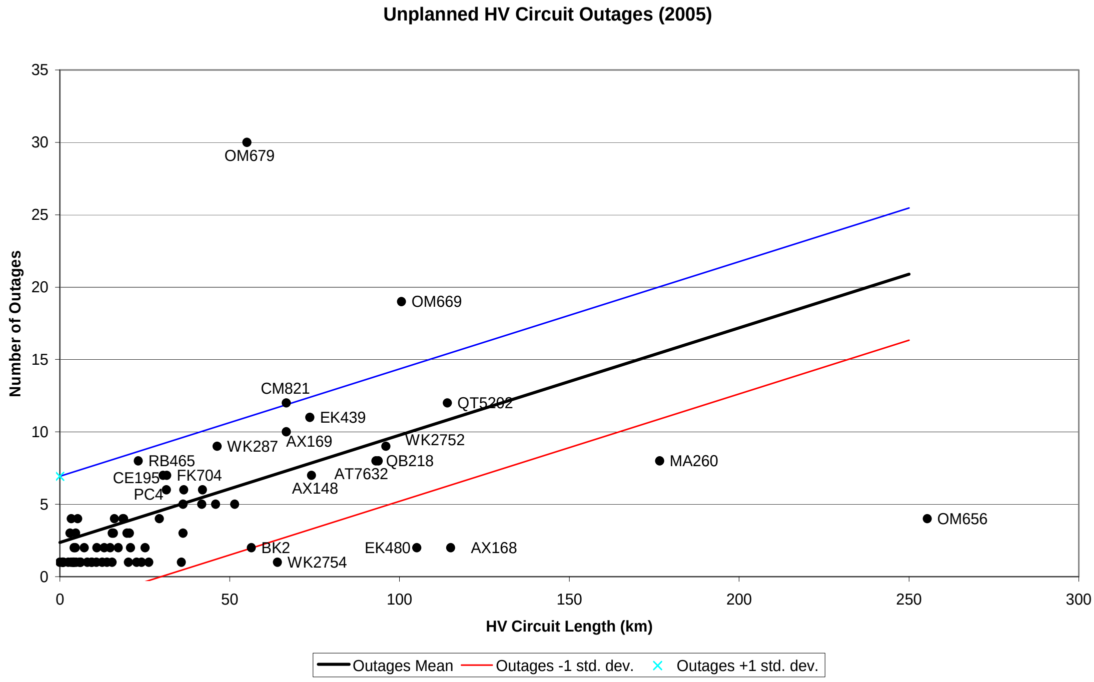

Figure 5.3 – HV Feeder Outages as a function of Feeder length

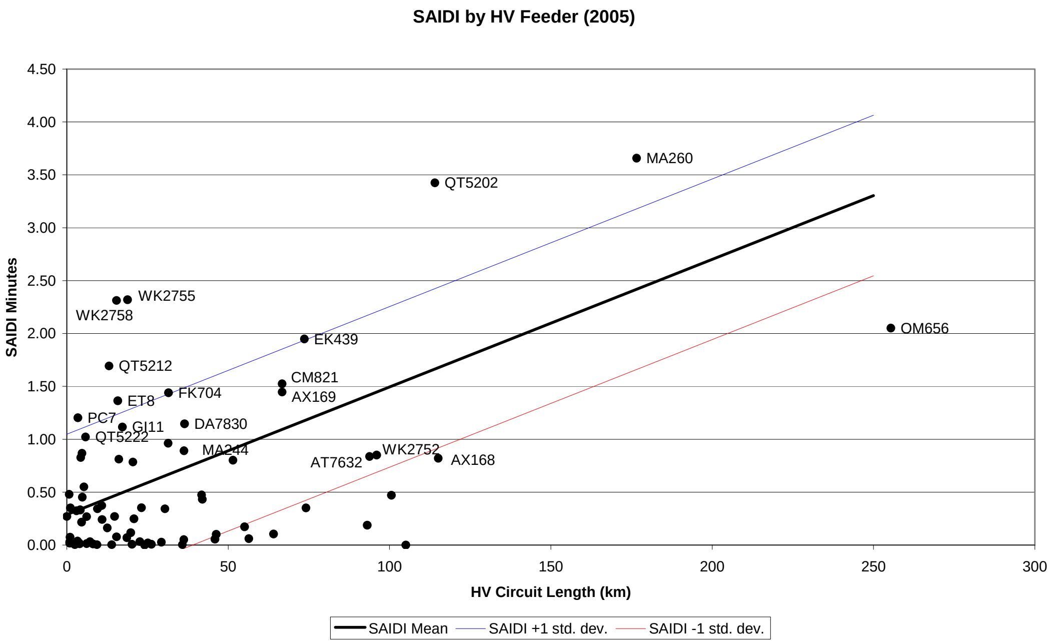

Figure 5.4 – HV Feeder Customer Outage Minutes by HV Feeder

5.15 Overhead to Underground Conversion Projects

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

Each year, the budgets are adjusted to match the actual distribution line income received in the previous financial year.

The projected expenditure by local authority area is detailed in Table 5.8 below.

Authority	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
DCC ($1,000)	1,485	1,500	1,510	1,530	1,545	1,560	1,575	1,590	1,600	1,620
QLDC ($1,000)	320		440	445	450	460	470	480	490	500
CODC ($1,000)	265	270	270	275	285	290	295	300	310	320

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

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. Customers make a contribution toward the cost of this work in accordance with the Aurora capital investment policy. There are three categories of new customer connections:

- subdivisions;
- minor individual connections (<100A) to the existing LV distribution network;
- individual connections that are not minor.

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.

Whilst this forecast is shown as a constant $7.2 million per year, we expect some slight variations from year to year. Whilst internal economic activity may reduce in the short term, that can be compensated by increased economic activity due to funding by international investors especially in the Queenstown and Wanaka areas.

6 Lifecycle Asset Management Planning for Maintenance and Renewal

6.1 Maintenance Planning Criteria and Assumptions

The prime asset management considerations are customer service and economic efficiency which act against the background of safety and environmental responsibility.

Maintenance work comprises two main elements:

- routine inspection, servicing, and testing to monitor asset condition, and
- renewal and refurbishment of assets when their condition is such that corrective action is most economic.

Typical components of maintenance expenditure according to maintenance activity are as follows:

- routine inspection and tests 8%
- special inspections 2%
- planned refurbishment 56%
- planned renewals 13%
- fault refurbishments 21%

Effective maintenance management involves balancing the cost of maintenance against 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 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 which will contain detailed condition information on all assets.

Different approaches are required for different assets. Generally, specific unit cost and condition-based analysis is undertaken for major expenditure items:

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 8% of Aurora's maintenance expenditure is for periodic inspections, servicing and tests, to ensure that defects or emerging risks are identified and mitigated. Servicing can also involve minor component replacements (e.g. 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).

Sub-transmission 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 and the interval monitored against failure rates. These services vary from annual servicing costing in the order of a few hundred dollars per breaker, to major overhaul costing up to several thousand dollars occurring infrequently. 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 (e.g., 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 (e.g. distribution transformer corrosion and power transformer insulation embrittlement).

6.2.1 Sub Transmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and solid types. Pressure alarms are installed on the former two and these are tested at six-monthly intervals and the outer sheath integrity on most cables 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. The impregnated paper solid insulation type cables are virtually maintenance free but faults occasionally occur due to insulation flow on hill sections or if they have been damaged by third parties (e.g. road openings etc). An above-ground inspection programme is in place, which involves inspecting the route of each cable for ground disturbance or ground movement.

Overhead Lines

Annual drive-by patrols are carried out on the overhead 66kV and 33kV lines to provide a quick check on such aspects as tree growth, leaning poles or broken insulators, etc. All overhead lines and poles are closely inspected on a five-year cycle 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. All transformers have their insulating oil tested annually for acid level, breakdown resistance and moisture content.

Tests are carried out on winding and oil temperature alarms from source and Buchholz relay operation at 2.5-year intervals with the 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 ten-year building maintenance plan details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services and the interior.

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, Isolators and Structures

Oil circuit breakers are given a routine minor service at 2.5-year intervals and a major overhaul every 5 years and 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 Dunedin ripple injection plant 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.

Earth connections for all equipment above ground level are inspected and maintained at five-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 five-yearly intervals for changes in value. Sample underground connections to the main earth grid are also checked at five-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 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 circuit breaker minor servicing work.

Portable fire extinguishers and the CO_2 flood systems in load control coupling cell cubicles are inspected annually. Pressure cylinders are tested at regulation intervals dependent upon age. The inspection is carried out internally and repairs and pressure testing by external contract.

Buildings are serviced by contract cleaning staff at fortnightly intervals. Grounds maintenance is outsourced.

6.2.3 HV and LV Lines and Cables

At present, lines are inspected approximately every two years, but this is being reviewed due to the new Hazards from Trees Regulations that came into effect from 1 July 2005. A précis of these 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 Dunedin central business district, no routine inspections of cables or associated equipment is made.

Earths

General distribution system earths are tested at six-yearly intervals but 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

Transformers

Expenditure on transformer maintenance is expected to increase as large numbers of transformers reach their economic life.

Substations

Ground-mounted substations which 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 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, power supplies, 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, 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 inspection and costs to meet agreed service targets over the next 10 years will be generally in line with the figures shown in Table 6.1.

Financial Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Sub-transmission	50	51	53	54	55	57	58	59	61	62
Zone substations	122	124	128	132	135	138	141	145	148	152
System control	11	11	11	12	12	12	13	13	13	13
HV and LV	776	786	814	834	853	874	895	916	938	960
Distribution substations	137	139	144	147	151	155	158	162	166	170
Total	**1,096**	**1,110**	**1,151**	**1,178**	**1,206**	**1,235**	**1,265**	**1,295**	**1,326**	**1,358**

Table 6.1 – Routine and Preventative Inspection Costs Summary ($000)

6.3 Asset Renewal and Refurbishment Policies

6.3.1 Planned Renewal and Refurbishment

Around 69% 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 a financial year. The remainder comprises a large number of what are typically minor component refurbishment (e.g. 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 21% 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, e.g. a spare transformer unit. The faulted unit can then be refurbished later, or a decision may be taken to dispose of it 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, along with the environment along each line section. A set of uniform predictions of the life of each type of component in each environment has been created. The life is defined as the time remaining until the component will be classed as defective.

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 and their 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 as has been used for circuit breakers is utilised for assessing renewal/refurbishment for transformers.

Where pro-active 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 Sub Transmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and solid types. On the former two leaks occasionally develop, usually at joints or where the cables have been stressed on installation. Faults refurbishment is expensive, being very labour intensive. The impregnated paper solid insulation type cables are virtually maintenance free but faults occasionally occur due to insulation flow on hill sections or if they have been damaged by third parties (e.g. road openings etc).

Overhead Lines

No 66kV or 33kV overhead lines have been identified as requiring renewal or refurbishment.

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 and only one transformer renewal is considered necessary within the planning period (for the Berwick transformer due to age, inadequate tapping range and a non-standard vector group).

Tapchangers are refurbished based on a predetermined number of operations between refurbishment. 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

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

One hundred and eighty 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.

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 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 CBD where many obsolete link pillars have been renewed with modern units which provide a safer and more flexible system. This work has now been extended to Wanaka and Alexandra 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 27 pedestal-mounted transformers are to be renewed. They have been identified as being a latent safety concern. Presently, 4-5 per year are planned to be renewed with ground-mounted substations.

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 inspection will be refurbished as required.

Switchgear

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

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 inspection will be refurbished as required.

6.4.6 Expenditure Projections

It is expected that the renewal and refurbishment costs, including fault repairs, to meet agreed service targets over the next 10 years, will be generally in line with the figures shown in Table 6.2.

Financial Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Sub-transmission	450	459	475	487	498	510	522	535	548	561
Zone substations	1,098	1,116	1,156	1,184	1,212	1,241	1,270	1,301	1,332	1,364
System control	98	99	103	105	107	110	113	115	118	121
HV and LV	6,984	7,074	7,327	7,502	7,681	7,864	8,052	8,244	8,442	8,644
Distribution substations	1,230	1,251	1,296	1,327	1,358	1,391	1,424	1,458	1,493	1,529
Total	**9,860**	**9,999**	**10,357**	**10,604**	**10,857**	**11,116**	**11,381**	**11,653**	**11,932**	**12,218**

Table 6.2 – Maintenance and Refurbishment Costs Summary ($000)

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. 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 detailed in Table 6.3. 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.

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	2.35	Has a tie to Neville Street
HWB–Willowbank	1963	3.95		
HWB–Smith Street	1959	3.2		
SthDn–Andersons Bay	1961	2.7		

Table 6.3 – Schedule of 33kV Gas cables

The direct cost of repairing gas cable leaks in 2003/04 was $156,000 and in 2004/05 was $225,000. This in itself is not grounds for cable replacement; but initial analysis after taking cost of non supply into consideration indicates that replacement may become economic.

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 indicate the tie cable is in good condition.

A preliminary plan has been developed which requires two projects to be completed within the planning period which are detailed below. Further analysis is required to confirm whether this plan is the most appropriate.

- 2007/08 - install 33kV tie cable between Smith Street and Willowbank with associated 33kV switchgear — estimate $2.8 million
- 2008/09 – install new 33kV cables between South Dunedin GXP and Neville Street — estimate $1.6 million

6.5.2 Berwick Substation Upgrade

To eliminate the risk of failure, it is intended to replace the two, 74 year old, Berwick zone substation 0.937MVA transformers and the 58 year old voltage regulator with a single 3MVA 33/11/6.6kV transformer. It is also proposed to replace the 50 year old 33kV circuit breaker. The upgrade will facilitate the eventual conversion of the Berwick area to 11kV distribution.

It will enable Berwick and Outram feeders to be paralleled which cannot be done at present because the Berwick transformers are a non standard vector group. It will also eliminate the transient low voltage problems at Berwick experienced during some operating conditions. The cost estimate is $430,000.

6.5.3 Ward St Substation Upgrade

The transformers and 6.6kV switchgear at Ward Street were installed in 1938 (68 years old). Additional switchgear was added in 1943 and 1951. It is proposed that the entire substation be rebuilt during the summer of 2008. The ODV replacement cost of the Ward Street substation is $3.7 million but its ODRC value is only $0.2 million due to optimisation and much of the equipment being older than the standard lives. The cost estimate is $3.0 million.

6.5.4 Zone Substation 6.6/11kV Switchgear Replacement

The following zone substation 6.6/11kV switchgear is older than their ODV life (40 years). The switchgear tentatively scheduled for replacement is listed in Table 6.4 below.

Substation	Manufacture Year	Status	Number CBs	Year*	Cost
Cromwell	1950	Underway	9	2005/06	Note 1
Roxburgh	1950	Planned	1	2007/08	$ 30,000
Ward Street	1938	Planned	14	2008/09	Note 3
Frankton	1950	Planned	8	2007/08	Note 2
Mosgiel	1954	Planned	10	2008/09	$650,000
Neville Street	1953	Monitor	14	2009/10	$700,000
Remarkables	1950	Monitor	1		
Halfway Bush	1956	Monitor	16	-	
Green Island	1957	Monitor	15	-	
Smith Street	1958	Monitor	15	-	
Earnscleugh	1960	Monitor	1	-	
Dalefield	1960	Monitor	1		
Outram	1963	Monitor	8		

Table 6.4 – Zone Substation 6.6/11kV Switchgear Replacement Schedule

Note 1: Switchgear replacement part of major substation upgrade currently underway - see Section 8.2.2.

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

Note 3: Switchgear replacement part of major substation upgrade - see Section 6.5.3.

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

6.5.5 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 this switchgear but maintenance costs and reliability will continue to be monitored. The applicable sites are listed in Table 6.5.

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
Gt King St Rectifier	Reyrolle	1948	Monitor	70
Shacklocks	Statter AC2	1960	Monitor	70
High Street	Statter AC2	1960	Monitor	50

Table 6.5 – Distribution Substation HV Switchgear Replacement Schedule

6.5.6 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 Hertz 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 317 Hz injection plants – one at the South Dunedin GXP and two at the Halfway Bush GXP. These would eventually replace 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.

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. 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. The cost estimate is $1,450,000.

6.5.7 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.

7 Risk Policies, Assessment, and Mitigation

7.1 Methods, Details and Conclusions of Risk Analysis

Aurora must manage risks imposed by technological change, economic alternatives, load changes and embedded generation. These are addressed by reducing the design life of assets likely to be bypassed and addressing maintenance expenditure accordingly. All new projects or extensions are considered and proceed only if revenue security is obtained. The following factors underpin many of the network operational decisions.

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, reducing and managing the consequences of each risk event.
- All such documents will be prepared, issued and managed in accordance with the Policy Management document.
- All policy documents should be traceable (via hyperlinks) back to the risk management policy document. If it relates to risk management then it should explicitly state which risk it relates to.
- This risk management policy specifies the risk areas for which formal policies will be maintained, as set out below.

Generic Risk Area	Sub-Category	Policy Reference
Asset protection	Safe-keeping	▪ Electricity Distribution Quality System ▪ Risk Management for Electricity Networks Policy (QM20)
	Maintenance of service potential	
	Replacement planning	
Customer service	Product/service quality	▪ Quality System Coverage Scope and Definitions policy
	Complaints	▪ Handling of Complaints policy
Disaster – fire, flood, earthquake, tsunami, chemical spill, etc		▪ Contracting Hazard Register Index ▪ Network Risk Management policy
Employment	Employee relations	▪ Standard Conditions of Employment policy ▪ Individual Employment Agreement template
	Health and safety	▪ Health and Safety policy
	Maintenance of work skill capability	▪ Training and Staff Competence ▪ Pandemic Planning
Environmental protection		▪ Environmental Policy

Generic Risk Area	Sub-Category	Policy Reference
Financial management	Interest rate exposure	
	Liquidity	
	Re-financing	
	Defalcation	
	Fraud	▪ Fraud and Other Similar Irregularities policy ▪ Protected Disclosures policy ▪ Delegations Policy
Information systems	Financial systems	
	Archives	
	Filing system	
Legal compliance	Health and Safety in Employment Act	▪ Health and Safety 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

To complement this policy, external audits are undertaken to ensure a holistic view is obtained. 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 form one piece of equipment to another.
- May 2005. All ground-mounted transformers were assessed for risk of being hit by a vehicle and resulting in oil leak into a water way. A small number of transformers have been identified as high risk and mitigation options are currently being considered. One Transformer site has had additional traffic protection measures installed.

The recommendations from the above reports are part of a structured risk reduction programme, with the emphasis being on contractor education in respect of accidental excavation of buried cables, standardisation of the level of intruder/vandal proofing at zone substations and addressing potential flooding issues at some zone substations.

Another external review is planned in 2006/07 focusing on reliability issues. Stakeholder feedback on appropriate reliability parameters would be appreciated.

During the flash floods in Dunedin in early February 2005, five, of twenty, underground distribution substations were flooded. A review has been completed and remedial works to make the vaults more watertight is programmed to be completed over the next three years on a priority basis.

7.1.2 Injection Performance

Supply availability and reliability to zone substations is dependent upon both the security of supply from the five Grid Exit Points within the network areas and the security and level of embedded generation connected into those Grid Exit Point systems.

	n-1 Transpower Capacity MVA	Embedded Generation MW	Expected Controlled Load Demand 2006 MW	n-1 Security
Halfway Bush	144	44	127.2	No[5]
South Dunedin	100	-	66.8	Yes
Clyde	60	17	17.5	Yes
Frankton	38	2	41.8	No[6]
Cromwell	30	4	25.5	Yes

Table 7.1 – Injection Security

7.1.3 Network Capacity (i.e. 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 grid are designed.

7.1.4 Network Reliability (i.e. Continuity of Service)

Reliability is a function of:

- equipment redundancy which either avoids an interruption or shortens restoration times;
- asset condition which affects the likelihood of failure of a component;
- operation practices which reduce restoration time.

While, ultimately, it is customers' requirements and financial commitments which drive work which might alter system reliability, expenditure is presently planned to achieve a long-term reliability target of 90 minutes without supply per customer per year.

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

7.1.5 Safety

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

[5] Halfway Bush does not have n-1 security unless there is significant Waipori generation. Long term it is planned to move the Neville St substation load to the South Dunedin GXP when the Neville St gas cables require replacement. This would reduce the demand on HWB by approximately 13MVA. In the short term, should the Transpower 100MVA transformer at HWB fail, TrustPower would be asked to increase its 33kV generation up to 44MW, and up to 5MW would be transferred to the South Dunedin GXP via the 6.6kV network.

[6] Refer to Section 5.9.2

The Health and Safety in Employment Act is a key item of safety legislation impacting on Aurora. While not overriding safety requirements found in Electricity Acts and Regulations, the 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 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 Rules, Electricity Industry” which is a set of safety rules for the New Zealand Electricity Generation Transmission and Distribution Industry and the “General Safety Handbook, Electricity Industry”. These two publications are industry-accepted standards and provide a means of complying with the safety requirements of the Health and Safety in Employment Act and the Electricity Act and Electricity Regulations and subsequent amendments.

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

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

7.1.6 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. Aurora has installed transformer oil containment facilities at all locations where oil quantity exceeds 1000 litres. 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.

Aurora is complying with the new tree trimming regulations, as per policy QP 1511, as a result of the Electricity (Hazards from Trees) Regulations 2003 which came into effect on 1 July 2005. The subtransmission lines are being targeted as the initial priority.

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 general guidelines for response to abnormal conditions created by either a civil defence emergency or plant and system failure and are directed towards minimising the emergency and the prioritisation of restoration of electricity supplies.

7.2.2 Civil Defence

DELTA has a comprehensive plan for and response to emergency situations and to liaise with the local Civil Defence organisations for the effective use and co-ordination of resources within its electrical supply area in those circumstances.

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 by a series of documents under 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 an "n-2" event.

8 Performance Measurement, Evaluation and Improvement

8.1 Review of Physical Performance

The System Average Interruption Duration Index provides an overall measure of asset performance for the year. On this basis, asset performance was better than planned, after excluding Transpower events.

Category	05-06 Plan	Actual
SAIDI	Minutes	Minutes
Unplanned		
Underlying	64	71
Significant events	10	0
Planned	5	12
	89	83
Transpower	1	14
TOTAL	90	97
SAIFI	**#**	**#**
Unplanned by Aurora	1.36	1.40

Table 8.1 – Expected v Actual SAIDI Minutes and SAIFI 2005-2006

For unplanned interruptions, the "underlying" pattern was 7 minutes above target. Significant events were 10 minutes better than target but there was a Transpower interruption, resulting in the total being 7.8% over target.

System performance is categorised to eliminate causes outside the normal span of control of Aurora, 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 in order to identify areas that may produce cost effective minimising of disruption from those events.

The secondary performance measure is "unplanned by line owner SAIFI" as described in Section 4.1 As this was only below target by 3% no remedial measures are currently being considered.

8.2 Review of Financial Performance

8.2.1 Operating and Maintenance Expenditure

For the year in review, planned maintenance activities have generally been completed in line with the maintenance standards. Of particular note are:

- overhead line inspections have been completed as scheduled;
- distribution transformer earth testing in the Central area that was not completed as stated in the last Asset Management Plan was completed in the year;
- thermal imaging of all zone substation equipment and major distribution assets was carried out - repairs as necessary have been completed;

- on the sub-transmission system, there were more sheath faults on the Dunedin 33kV gas cables than expected; however, this was partly offset by less faults in the Central area than anticipated;
- the SCADA upgrade completed early in 2006 combined with good support under a new maintenance agreement with the Australian supplier is the reason for the large positive variance in System Control costs.;
- subtransmission expenditure was 10% less than budget due to the low incidence of cable faults compared to previous years.

A comparison of Aurora's operating and maintenance expenditure against budget is shown below:

Category	Budget ($000)	Actual ($000)	Variance	
Distribution Substation	1,210	1,150	-61	5%
HV and LV Lines and Cables	7,466	7,541	-75	-1%
Zone Substations	1,065	1,054	11	1%
Sub Transmission	847	762	85	10%
System Control	228	114	114	50%
Total	10,816	10,621	195	2%

Table 8.2 – Operating and Maintenance Expenditure Budget Compared to Actual

8.2.2 Capital Expenditure

Overall, capital expenditure was ahead of budget projections, mainly due to customer demand.

New connections were above budget, mainly in Central, by 34% which is an increase on the previous year ($7.3 million).

Localised growth is a combination of customer-funded works due to their requirement for more load, and the correction of voltage complaints. The higher-than-planned volume of customer-funded initiatives mirrored local growth and was also higher than budget.

Category	2005/06 Actual ($000)	2005/06 Budget ($000)	Variance
New Connections	9,500	7,100	34%
Localised Growth	2,300	1,900	21%
System Development including SCADA	290	299	-3%
Undergrounding Projects	1,300	1,646	-21%
Closeburn Zone Substation	50	300	-83%
Glenorchy Zone Substation	0	550	-100%
Closeburn Regulators	150	0	
Glenorchy Regulators	140	0	
Emergency Generators	150	150	0%
Cromwell MEN	40	87	8%
Port Chalmers 11kV Switchgear	550	560	-2%
Cromwell 11kV Switchgear	200	700	-71%
Total	14,670	13,292	10%

Table 8.3 – Comparison of Actual Capital Expenditure with Plan

The Closeburn and Glenorchy substations projects were deferred by installing voltage regulators at these sites.

The Cromwell MEN project was delayed due to customer funded work taking a higher priority and will be completed by October 2006.

The Cromwell 11kV project is taking longer than anticipated due to the transfer of design resources to higher priority projects. This project is expected to be complete by October 2006.

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 identified in the last year.

All unplanned interruptions exceeding 0.5 minutes of SAIDI, (formerly 1.0 minute), 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:

- dual supply to the Clyde Earnscleugh substation (approved);
- replacement of the 11kV Cromwell switchgear and duplication of the 33kV supply to this zone substation (underway);
- Berwick zone substation upgrade (approved).

A review of record keeping practices is planned in 2006/07.

9 Glossary of Terms

CPD	Congestion Period Demand
CAIDI	Consumer Average Interruption Duration Index
DRC	Depreciated Replacement Cost
DSM	Demand side management
GXPs	Grid Exit Points
HWB	Halfway Bush
Hz	Hertz
IEDs	Intelligent Electronic Devices
MDIs	Maximum Demand Indicators
MVA	Megavolt amps
MW	Megawatts (one million watts)
pf	power factor
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 Incident Frequency Index