AURORA ENERGY LTD

Asset Management Plan
Number 12

April 2005-March 2015

Revised 29 June 2005

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

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FOREWORD

This is the twelfth Network Asset Management Plan for the distribution network owned by Aurora Energy Ltd and covers the 10 year period from 1 April 2005. 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.

DISCLAIMER

1 Executive Summary

1.1 Purpose

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

While there is a legal obligation to disclose an asset management plan, and detailed topic areas are specified in the regulations, there is little guidance on the detail required. This disclosure concentrates on asset management principles and overall indicators of asset condition. Existing or potential users of the network assets may request more details regarding the specific assets that affect them.

1.2 Date Completed and Period to Which it Relates

This plan was amended in June 2005 following comment received from the Commerce Commission, and relates to the 2005-2015 period.

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

1.3 Consultation

For some years, Aurora has actively sought comment on its Asset Management, including through newspaper advertisements and direct approaches. No comment has been received in response.

Aurora’s primary service level target for asset performance is continuously tested by market survey for which a response rate of 20% is achieved.

1.4 Asset Management Systems and Information

Aurora has contracted the management of its assets to related company *DELTA* Utility Services Ltd, under a 10-year performance-related contract that expires on 30 June 2008. The primary deliverable under this contract is annually specified network reliability, with significant financial penalty for performance failure.

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.

1.5 Network and Asset Description

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	RC	%	Quantity
Subtransmission	$41,157,937	10%	591 km
Zone Substations	$74,312,947	18%	36
HV Distribution	$118,606,407	29%	2936 km
Distribution Switchgear	$35,647,187	9%	10998
Distribution Transformers	$46,170,200	11%	5592
Distribution Substations	$9,479,000	2%	5513
LV Distribution	$63,392,829	16%	2656 km
Service Connections	$10,152,290	3%	74,864
Street Lighting Distribution	$4,024,300	1%	142 km
Sundry	$562,593	0%	
System Control	$1,570,200	0%	
Total	**$405,075,892**	**100%**	

Table 1.1 – Types and Quantities of Assets (from 2004 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.

1.6 Service Level Objectives

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.
Response Time - Dunedin Network Area Restore supply in response to “no power” call. Restore supply following general network failure.	 Within 2 hours of notification. Within 4 hours of notification.
Response Time - Central Network Area♦ Restore supply in response to “no power” call. Restore supply following general network failure.	 Within 3 hours of notification. Within 6 hours of notification.

Table 1.2 – Service Level Objectives

♦ The different standards for the Central network result from the different Use-of-System Agreement held by the incumbent retailer at the time of purchase.

1.7 Maintenance Policies and Projected Expenditures

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. Current expectations are that the expenditure projections[1] shown below are necessary to meet expected load growth and agreed service targets.

Financial Year	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Sub-transmission	494	500	507	514	521	528	535	542	544	546
Zone Substations	1,204	1,220	1,236	1,252	1,268	1,284	1,301	1,318	1,335	1,352
System Control	108	109	110	112	113	114	116	116	118	120
HV and LV Lines and Cables	7,660	7,760	7,861	7,963	8,067	8,172	8,278	8,385	8,494	8,604
Distribution Sub-stations	1,350	1,367	1,385	1,403	1,421	1,440	1,458	1,478	1,497	1,516
Total Expenditure	10,816	10,956	11,099	11,244	11,390	11,538	11,688	11,840	11,994	12,138

Table 1.3 – Maintenance Expenditure Forecast ($000)

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
New Customers	7,100	7,100	6,100	5,900	5,800	5,800	5,600	5,600	5,600	5,600
Local Growth including renewals	1,900	2,000	2,040	2,081	2,122	2,122	2,264	2,421	2,593	2,782
System Development including SCADA	2,289	1,510	2,692	2,218	3,236	3,607	3,347	4,285	4,520	4,750
Undergrounding	1,468	1,483	1,598	2,003	2,028	2,053	2,078	2,104	2,130	2,156
Ripple Injection		600		600			700			
Total	12,757	12,693	12,430	12,802	13,186	13,582	13,990	14,409	14,842	15,287

Table 1.4 – Capital Expenditure Forecast ($000)

Capital expenditure associated with “New Customers” results directly from applications for new network connections. Expenditure required by increased load on existing connections is defined as “Local Growth” and “System Development” capital investment. These assumptions are reviewed annually and the appropriate adjustments made to the capital expenditure forecast. Additional information regarding zone substation development expenditure is given in 6.3.

New Customer investment is significantly funded by the customers via capital contributions. The current boom in Central Otago is forecast to taper off from the 2007/08 year. New Customer works are monitored on a quarterly basis and currently show no tendency to taper off.

Aurora’s policy is to invest 2% of distribution charges back into the community for undergrounding works, funded on a one-to-one basis with the community. Funds were advanced in the Queenstown Lakes District Council (QLDC) area to facilitate the undergrounding of the Frankton Road project “ahead of income”. Whilst small scale projects continue in the QLDC area, such as opportunistic ducting projects in conjunction with watermains contracts, substantial funding of new projects in this area will not occur until 2007/08. The Central Otago District Council has begun to take advantage of this policy, with two projects being completed in 2003.

[1] All future costs are expressed as nominal costs

The economics of replacing the zone substation ripple injection plants with GXP injection plant in Dunedin are still being assessed. If this does not take place the existing ripple injection units in the Dunedin zone substations will require replacement in the years 2007, 2009 and 2012.

1.8 Statement of Opportunities

In previous plans, Aurora described the rapid growth occurring in the Wanaka Basin and invited interested parties to propose solutions to meet or manage this growing demand. None were offered and Aurora proceeded to upgrade the subtransmission system. Contact Energy subsequently announced proposals for up to 16MW generation on the Lake Hawea outlet. This illustrates the difficulty Aurora has in both identifying non-network opportunities and eliciting interest.

Opportunities now exist to alleviate the peak demand at the Frankton GXP. Parties interested in investing in either generation or demand-side alternatives are invited to contact Aurora. Joint venture options are a possibility. Local generators TrustPower Ltd and Pioneer Generation Ltd have been unable to offer any suggestions.

1.9 Lifecycle Asset Management and Development Plans

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, repair/replacement costs as well as the cost of non-supply. Likewise, asset replacement is determined when the Net Present Value (NPV) of the new asset exceeds the NPV of non replacement.

1.10 Risk Assessment

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.

1.11 Performance and Plans for Improvement

The diagram below compares the performance achieved by Aurora's network with that achieved by other line businesses in the year to 31 March 2004. When judged on the combination of low price (average distribution charge/kWh delivered) and high quality (SAIDI)[2], the Dunedin network was in the 'upper quartile' of the 29 distribution businesses. While such analysis is not a perfect indicator, it provides a degree of comfort. Accordingly, Aurora believes that the targets set out in this plan are appropriate given the results of its continual survey (see section 4.3).

[2] The data is from Information Disclosures for 2004

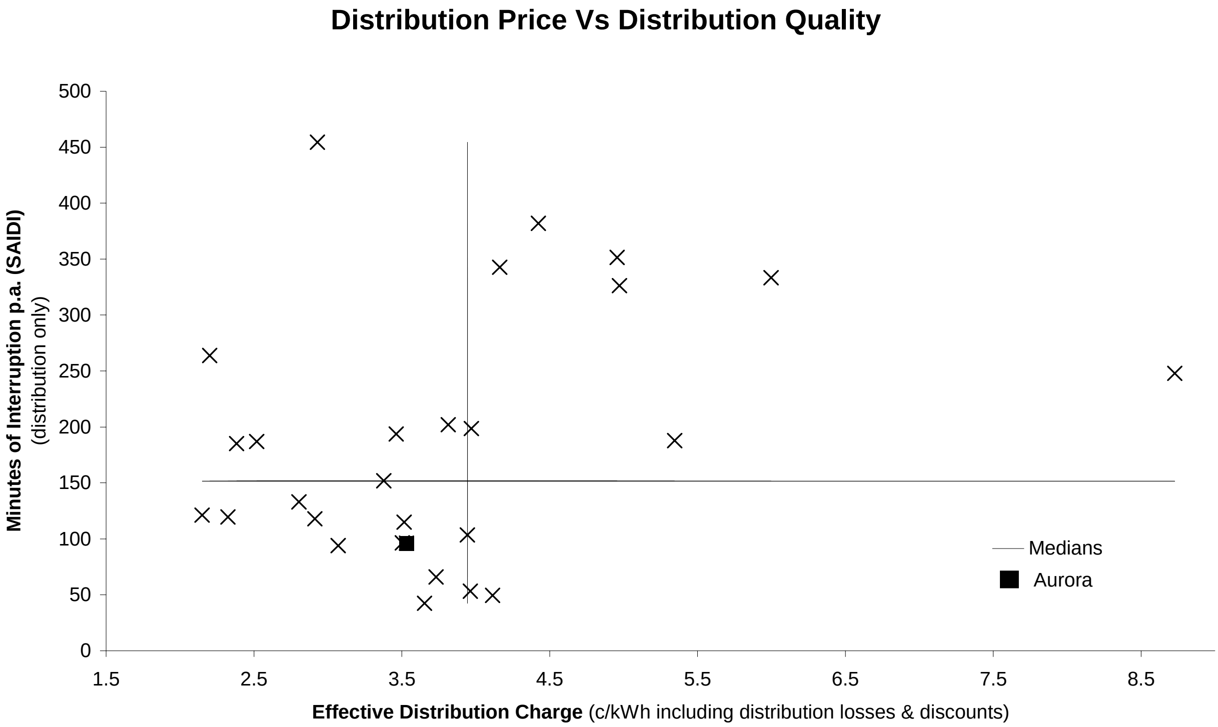

Figure 1.1 – Price-Quality Matrix

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

2 Background and Objectives

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 2005 to 31 March 2015 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 proposes specific asset developments to provide for anticipated load growth and appropriate asset replacement. Relevant details will be provided to interested parties on request.

2.1 Stakeholder Interests

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 follows:

Stakeholder	Interest
Contractors who provide services to Aurora	Fair contractual relationship Safety 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 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) Conversion of overhead to under-ground Local economic development Control of assets in road reserve
Transit NZ	Control of assets in road reserve

Table 2.1 – Stakeholder Interests

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

2.2 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 marginal supply 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.

2.3 Accountabilities and Responsibilities

Aurora has contracted asset management to related company *DELTA* under a 10-year performance-related contract. Under this contract *DELTA* is required to:

- deliver specified network performance and customer service over the 10-year contract, subject to financial penalty for non-performance
- deliver detailed development plans covering periods during and beyond the contract period.

Aurora receives regular and special reports from *DELTA* and meets monthly to review a range of operational indicators and to consider strategic issues.

2.4 Details of Asset Management Systems and Processes

The asset management information systems are built on 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.
- 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*.

3 Description of Asset Configuration, Categories, Age and Condition

The Aurora network covers two 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, whereas the Dunedin region allows much easier interconnection for added reliability.

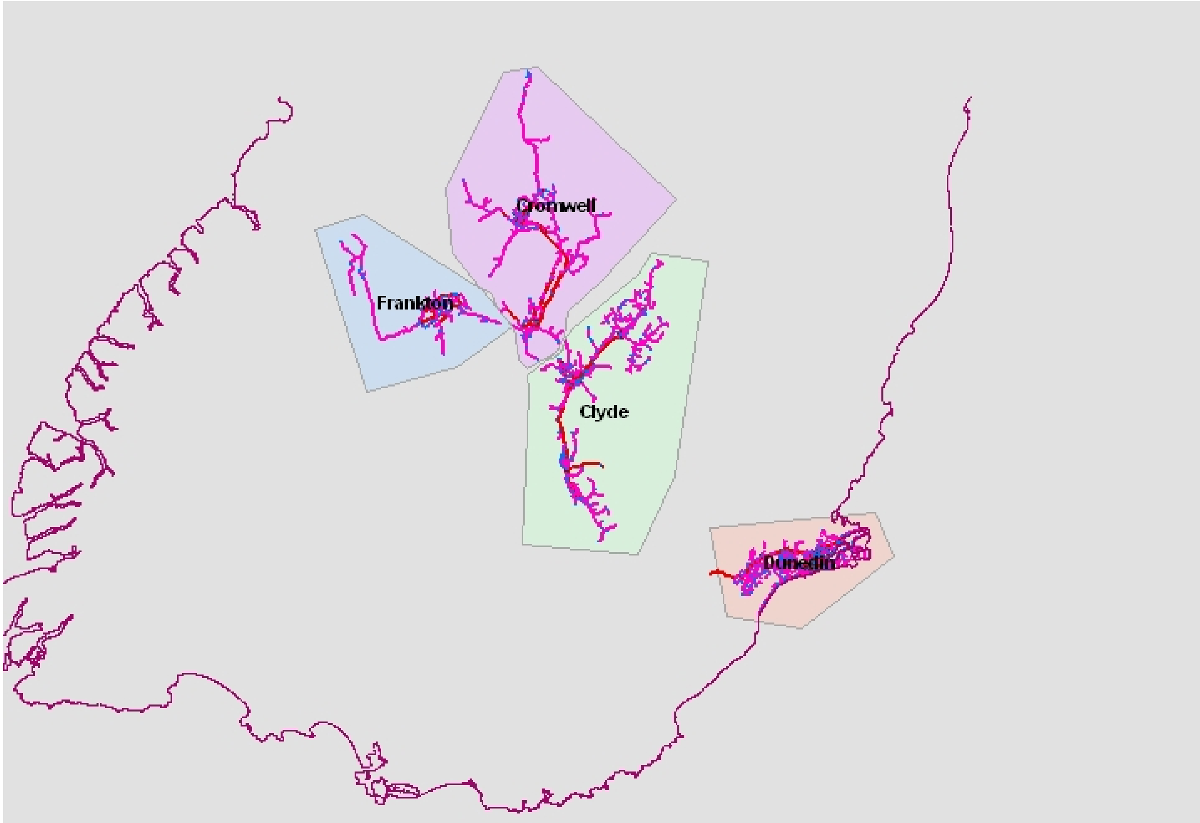

Figure 3.1 – Aurora Network

A schedule of assets by asset category appears as Table 1.1

All assets are justified by present or anticipated requirements except for those 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.

The remainder of this section of the plan describes specific asset groups and shows age profiles where this is useful. Minor modifications to age profiles occur from year to year as data is checked and confirmed. Very recent data (for the first year) may be artificially low due to a current data entry backlog.

3.1 Network Injection

The Dunedin network area is supplied from Transpower grid exit points at South Dunedin and Halfway Bush and from TrustPower's Waipori power scheme which injects at Berwick. The Central Otago network area consists of three areas Clyde, Cromwell and Frankton (shown in Figure 3.1) with no electrical interconnection. Each area is supplied from a Transpower grid exit point and from embedded power schemes as detailed in Table 3.1.

Network Area	Injection Point	Voltage	Energy	ICPs	Largest ICP	
			GWh		GWh	
1 Halfway Bush	Halfway Bush	33kV	519			
	Waipori	33kV	133			
			652	35,380	17.0	2.6%
2 South Dunedin	South Dunedin	33kV	316	16,200	18.1	5.7%
3 Wakatipu	Frankton	33kV	181			
	Wye Creek	33kV	8			
	Glenorchy	11kV	3			
			192	9,610	3.1	1.6%
4 Clyde	Clyde	33kV	7			
	Roxburgh	33kV	80			
	Fraser	33kV	9			
			96	6,250	1.1	1.1%
5 Cromwell	Cromwell	33kV	78			
	Roaring Meg	33kV	29			
			107	8,100	1.5	1.4%
Dunedin	71%		968	51,780		
Central	29%		395	23,960		
Aurora Total			1,363	75,740		

Table 3.1 – Network and Injection Points (2004-2005)

The largest consumer in terms of network impact, is the University of Otago supplied from South Dunedin GXP. However, the load is of a conventional CBD nature, consisting principally of office buildings.

3.2 Sub-Transmission

The Dunedin city urban area is supplied by 14 transformer-feeder zone substations, with each substation having two 33/6.6 kV transformers. However, the North East Valley zone substation is teed off the Port Chalmers zone substation feeders and the Taieri Plain area is served by four zone substations which are supplied from the three parallel 33kV lines between Transpower's Halfway Bush substation and TrustPower's Waipori Power Scheme at Berwick.

There are 18 zone substations in the Central network area. The six zone substations supplying significant urban areas each have a pair of transformers and at least two sub transmission supply routes. The 12 smaller zone substations (3 MVA and below) have a single transformer and in most cases a single 33 kV supply.

Table 3.2 summarises sub-transmission arrangements and indicates the degree of design redundancy justified by economic circumstances as detailed later in this plan. Also shown are the under-frequency load shedding arrangements Aurora is required to provide for security of the national grid.

	Grid Exit Point	Sub-Transmission	Zone Substation	n-1[3] Security	AUFLS[4]
1	Clyde	Single line from Roxburgh	Ettrick	N	N
2	Clyde	Via 2 lines to Alexandra	Roxburgh	Y	N
3	Clyde	Tee off on Alexandra to Roxburgh line	Roxburgh Hydro	N	N
4	Clyde	2 lines to Clyde GXP	Alexandra	Y	N
5	Clyde	Single line from Alexandra	Omakau	N	N
6	Clyde	Tee off one Alexandra to Clyde GXP line	Earnscleugh	N	N
7	Clyde	Tee off one Alexandra to Clyde GXP line	Clyde/ Earnscleugh	N	N
8	Cromwell	One line from Cromwell GXP	Cromwell	N	1
9	Cromwell	Tee from either Wanaka to Cromwell lines	Queensberry	N	2
10	Cromwell	2 lines from Clyde GXP	Wanaka	Y	2
11	Cromwell	Line from Wanaka	Maungawera	N	2
12	Frankton	Line from Frankton GXP open ring circuit	Arrowtown	N	1
13	Frankton	Line from Frankton GXP open ring circuit	Dalefield	N	1
14	Frankton	3 lines from Frankton GXP	Queenstown	Y	N
15	Frankton	2 XLPE cables from Queenstown	Fernhill	Y	N
16	Frankton	Tee off 2 of Queenstown to Frankton lines	Frankton	Y	N
17	Frankton	1 line from Frankton GXP	Remarkables	N	1
18	Frankton	Tee off Frankton Ring	Coronet Peak	N	1
19	Halfway Bush	Via Taieri sub-transmission lines	Berwick	Y	N
20	Halfway Bush	Oil Cable via Mosgiel and Taieri lines	East Taieri	Y	N
21	Halfway Bush	2 x line	Green Island	Y	2
22	Halfway Bush	2 x solid cable	Halfway Bush	Y	N
23	Halfway Bush	2 x solid cable	Kaikorai Valley	Y	N
24	Halfway Bush	Via Taieri sub-transmission line	Mosgiel	Y	N
25	Halfway Bush	2x gas cable	Neville Street	Y	1
26	Halfway Bush	2 x line and cable tee off Port Chalmers lines	North East Valley	Y	N
27	Halfway Bush	Via Taieri sub-transmission lines	Outram	Y	N
28	Halfway Bush	2 x line	Port Chalmers	Y	N
29	Halfway Bush	2 x gas cable	Smith Street	Y	N
30	Halfway Bush	2 x gas cable	Ward Street	Y	N
31	Halfway Bush	2 x gas cable	Willowbank	Y	1
32	South Dunedin	2 x gas cable	Andersons Bay	Y	1
33	South Dunedin	2 x oil cable	Corstorphine	Y	1
34	South Dunedin	2 x oil cable	North City	Y	N
35	South Dunedin	2 x oil cable	South City	Y	N
36	South Dunedin	2 x oil cable	St Kilda	Y	2

Table 3.2 – Subtransmission

[3] 'n-1'. The ability to supply full load with one component out of service.

[4] **A**utomatic **U**nder **F**requency **L**oad **S**hedding. Block 1: Feeder CB opens when system frequency falls below 47.5HZ for more than 150 ms. Block 2: Feeder CB opens when system frequency falls below 45.5HZ for more than 150 ms, Feeder CB opens when system frequency falls below 47.5Hz for more than 15 seconds.

3.2.1 Sub Transmission Lines

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.

The age profile of subtransmission lines (66 and 33kV) is shown in Figure 3.2 and is based on conductor age.

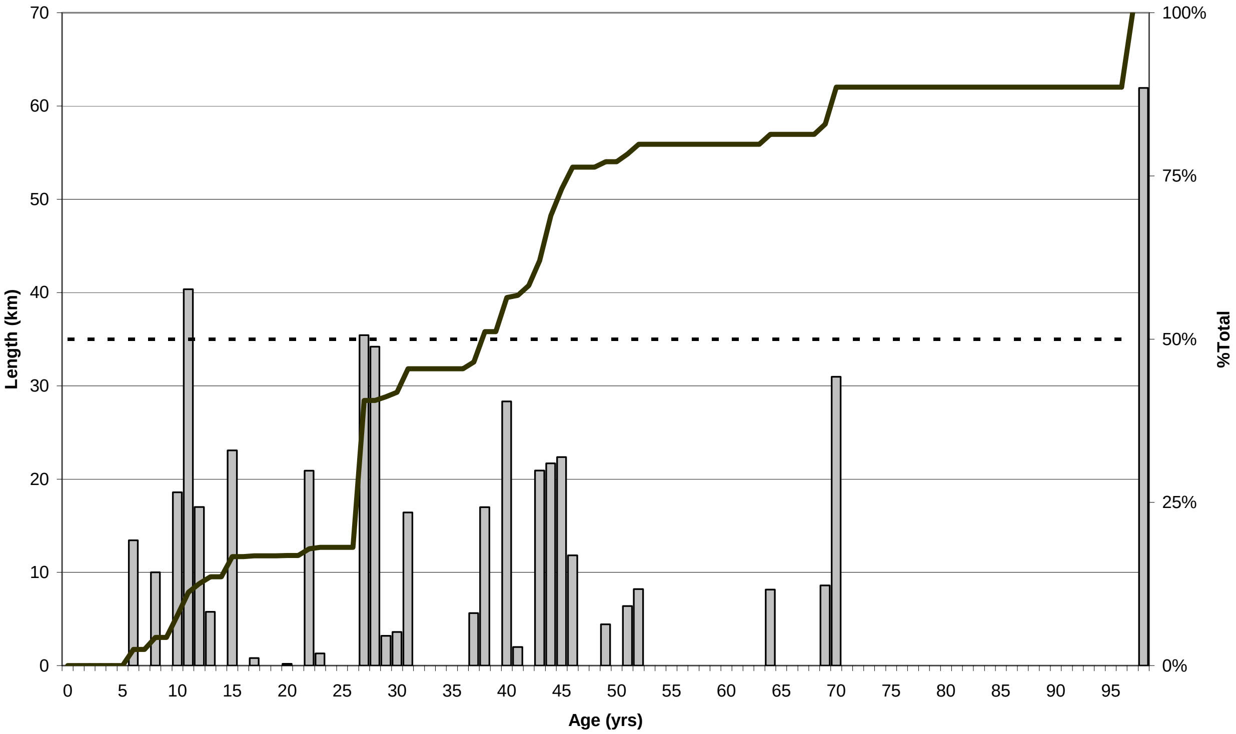

Figure 3.2 – 66 & 33 kV Lines Age Profile (Total = 591)

The lines shown at 93 years are the Taieri "A" and "B" lines to Waipori, where the conductor is that old, and is still performing well.

All lines are in good condition and no significant expenditure is expected within the planning period.

3.2.2 Subtransmission Cables

Following the Auckland CBD crisis in 1998, an independent investigation was undertaken to confirm the condition of Aurora's 33 kV cables and the maintenance practices employed for those cables. The report confirmed that most of the cables were in good condition. Subsequently, routine partial discharge testing has been adopted for 33kV cables.

The age profile of 33kV cables is shown in Figure 3.3.

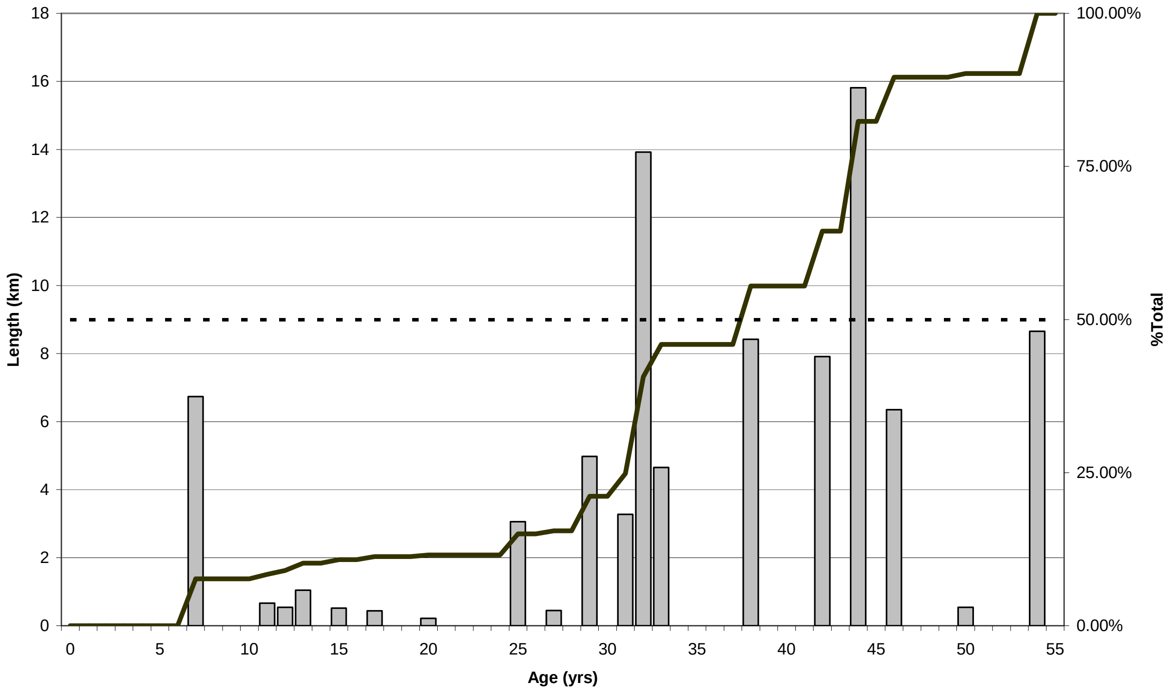

Figure 3.3 – 33 kV Cables Age Profile (Total 88 km)

The 33kV gas insulated cables from Halfway Bush grid exit point to Neville Street zone substation had experienced a series of leaks to warrant planning for alternatives and this fact was signalled in the 1999-09 Asset Management Plan. Preliminary cost/benefit analysis of this project completed in June 2001 indicated that replacement of these cables could not be justified. They recently experienced a series of leaks in the six months to December 2004. While no consumer outages occurred, further investigations into sub-transmission supply security will take place in 2005-2006.

3.3 Zone Substations

Zone substations comprise yards, buildings, switchyard structures and associated hard-ware, high voltage circuit breakers, power transformers, instrument transformers, reactors, load control equipment and associated power supplies, cabling and support equipment.

Table 3.3 summarises past and expected loadings and indicators when capacity constraints will be reached.

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				Historical Demands MVA								Predicted Future Demands MVA										
Zone Substation	**Transformer MVA**	**Firm Load MVA**	**n-1**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**Previous 6 yr Growth %/yr**	**Predicted Growth %/yr**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2014 U.F. Firm**
Alexandra	7.5/15+7.5/15	15	15	9.9	10	10.8	11.1	10	10.4	0.8%	2.0%	10.6	10.8	11.0	11.3	11.5	11.7	11.9	12.2	12.4	12.7	85%
Anderson's Bay	15 + 15	22.8	18	14	14	15.8	15.5	13.5	15.3	0.9%	1.0%	15.5	15.6	15.8	15.9	16.1	16.2	16.4	16.6	16.7	16.9	74%
Arrowtown	5 + 5	7.5	6	3.7	5.6	6	5.6	6.3	6.3	6.7%	6%	6.7	7.1	7.5	8.0	8.4	8.9	9.5	10.0	10.6	11.3	**150%**
Berwick	0.9 +0.9	2	0	0.85	1.2	0.9	1.2	1.2	1.11	4.1%	1.0%	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	61%
Clyde/Earnscleugh	4 +2	4.8	2.4	4	4.2	4.1	4.7	4.1	3.6	-1.3%	2.0%	3.7	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	91%
Coronet Peak	5	6	0	*	*	*	*	*	3.0	0.0%	3.0%	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	67%
Corstorphine	12/24 + 12/24	29	23	11.5	12	13	13.5	12.2	13.1	2.0%	1.0%	13.2	13.4	13.5	13.6	13.8	13.9	14.0	14.2	14.3	14.5	50%
Cromwell	5/10 + 7.5	7.0	6.4	5.4	6	6.2	6	6.6	7.1	4.1%	3.0%	7.3	7.5	7.8	8.0	8.2	8.5	8.7	9.0	9.3	9.5	**136%**
Dalefield	3	3.6	0	3.2	3.4	3	3	3	1.4	N/A	2.5%	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8	50%
Earnscleagh	2	2.4	0									0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
East Taieri	12/24 + 12/24	19	22	12.2	10.9	13.4	14.7	13.6	14.2	3.9%	2.0%	14.5	14.8	15.1	15.4	15.7	16.0	16.3	16.6	17.0	17.3	91%
Ettrick	3	3.6	0	*	1.8	1.6	2	2	1.8	2.0%	1.0%	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	55%
Frankton	7.5/15 +7.5/10	12	10	5.6	6.6	7.7	7.9	7.8	8	5.6%	6.0%	8.5	9.0	9.5	10.1	10.7	11.3	12.0	12.8	13.5	14.3	**119%**
Fernhill	7.5/10+7.5/10	10	0	4	4.6	5.1	4.8	5.2	5.2	4.1%	4%	5.4	5.6	5.8	6.1	6.3	6.6	6.8	7.1	7.4	7.7	77%
Green Island	15 + 15	24	18	11	12	13	12.5	12.9	13.6	3.2%	1.0%	13.7	13.9	14.0	14.2	14.3	14.4	14.6	14.7	14.9	15.0	63%
Halfway Bush	15 + 15	24	18	12	12	14	14.1	12.2	12.3	0.5%	0.5%	12.4	12.4	12.5	12.5	12.6	12.7	12.7	12.8	12.9	12.9	54%
Kaikorai Val.	12/24 + 12/24	28	22	10	9	11.8	9	9	10	-0.8%	1.0%	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	39%
Maungawera	3	3.6	0	*	2.1	1.9	2.3	1.9	2.2	0.8%	3.0%	2.3	2.3	2.4	2.5	2.6	2.6	2.7	2.8	2.9	3.0	82%
Mosgiel	10 + 10	13	12	13.4	15	14	12	11	11.6	-5.7%	2.0%	11.8	12.1	12.3	12.6	12.8	11.9	12.1	12.3	12.6	12.8	99%
Neville St	15 + 15	23	18	13	12.4	14.2	13.6	13	13.6	0.9%	0.5%	13.7	13.7	13.8	13.9	13.9	14.0	14.1	14.2	14.2	14.3	62%
North City	14/28 +14/28	34	28	19	19.4	21	21.1	21.1	20.4	1.7%	1.0%	20.6	20.8	21.0	21.2	21.4	21.7	21.9	22.1	22.3	22.5	66%
North East Val.	9/18 +12/18	23.9	18	11.5	11.3	11.3	11.4	10.22	11.4	-0.9%	0.5%	11.5	11.5	11.6	11.6	11.7	11.7	11.8	11.9	11.9	12.0	50%
Omakau	3	3.6	0	1.5	1.1	1.6	1.54	1.7	1.5	3.3%	1.0%	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.7	46%
Outram	3 + 3	3.6	3.6	2.4	2.3	3	2.5	2.5	2.6	1.2%	1.0%	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.9	80%
Port Chalmers	7.7 +7.5	11.4	9	7.2	7	8	7.5	7.6	7.9	1.7%	1.0%	8.0	8.1	8.2	8.2	8.3	8.4	8.5	8.6	8.7	8.8	77%
Queensberry	3	3.6	0	*	0.45	0.45	0.56	0.8	1.4	14.3%	6.0%	1.5	1.6	1.2	1.2	1.3	1.4	1.5	1.6	1.7	1.8	49%
Queenstown	10/20 +10/20	23	20	15.5	16.7	18.8	18.3	18	20.4	3.9%	4.0%	21.2	21.1	21.9	22.8	23.7	24.6	25.6	26.7	27.7	28.8	**125%**
Remarkables	1	1.2	0	0.7	0.7	0.8	0.75	0.8	0.8	2.7%	0.0%	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	67%
Roxburgh	1.5 +1.5	3.6	1.8	2.4	2.6	2.4	2.9	1.9	1.7	-8.6%	0.5%	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	50%
Roxburgh Hydro	1.8	2.16	0	0.9	1.1	0.8	0.63	0.85	0.8	-5.1%	0.0%	Decommission substation in 2005 load transfer to Roxburgh (0.8 MVA)										
Smith St	15 + 15	24	18	17	16.8	18.2	19	16	18.1	0.6%	1.0%	18.3	18.5	18.6	18.8	19.0	19.2	19.4	19.6	19.8	20.0	83%
South City	9/18 +9/18	24	18	11.8	12	13	13	11.8	13.6	1.8%	1.0%	13.7	13.9	14.0	14.2	14.3	14.4	14.6	14.7	14.9	15.0	63%
St Kilda	12/24 + 12/24	29	23	15	15	15	14.7	14.7	15.1	-0.1%	0.0%	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	52%
Wanaka	12/24 +12/24	25	23	9	10.6	11.9	11.4	11.5	13.6	5.3%	5%	14.3	15.0	15.7	16.5	17.4	18.2	19.1	20.1	21.1	22.2	89%
Ward St	15 + 15	24	18	10	11.8	11.6	11	10.4	10.9	-0.1%	0.0%	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	45%
Willowbank	15 + 15	24	18	12	13	14	12.2	12.1	13.7	0.8%	1.0%	13.8	14.0	14.1	14.3	14.4	14.5	14.7	14.8	15.0	15.1	63%
Closeburn	1	1.2	0							0.0%	2.0%		0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	45%
Glenorchy	1	1.2	0							0.0%	2.0%		0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	45%
Morven Ferry	3	3.6	0							0.0%	5.0%						1.2	1.3	1.3	1.4	1.5	33%
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%
Jacks Point	7.5/10	3.6	0							0.0%				1.3	1.8	2.2	2.7	3.1	3.6	4.0	4.5	61%

Table 3.3 – Zone Substation Loading Data

Comment to Table 3.3 - Earnscleugh is a standby substation for the frost fighting season.

3.3.1 Power Transformers

The age profile of zone substation transformers is shown in Figure 3.3. Transformers that are subject to prudent monitoring and maintenance practices should last for at least 60 years. The three 70+ year old units, are at Roxburgh Hydro and Berwick. The two Berwick transformers are scheduled to be replaced with a single 3MVA transformer in 2007, and the Roxburgh Hydro substation was decommissioned in May 2005.

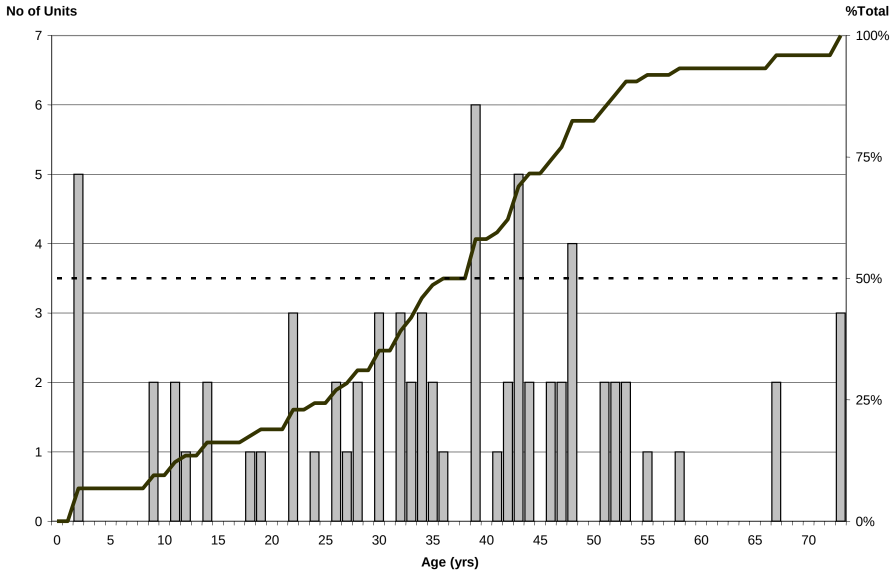

Figure 3.3 – 66 & 33 kV Zone Substation Transformers Age Profile (Total = 74)

3.3.2 66 & 33 kV Substation Circuit Breakers

The age profile of 66 & 33kV circuit breakers is shown in Figure 3.4. The 33 kV 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 St substations is scheduled during the planning period and the circuit breakers at Alexandra and North East Valley are being closely monitored.

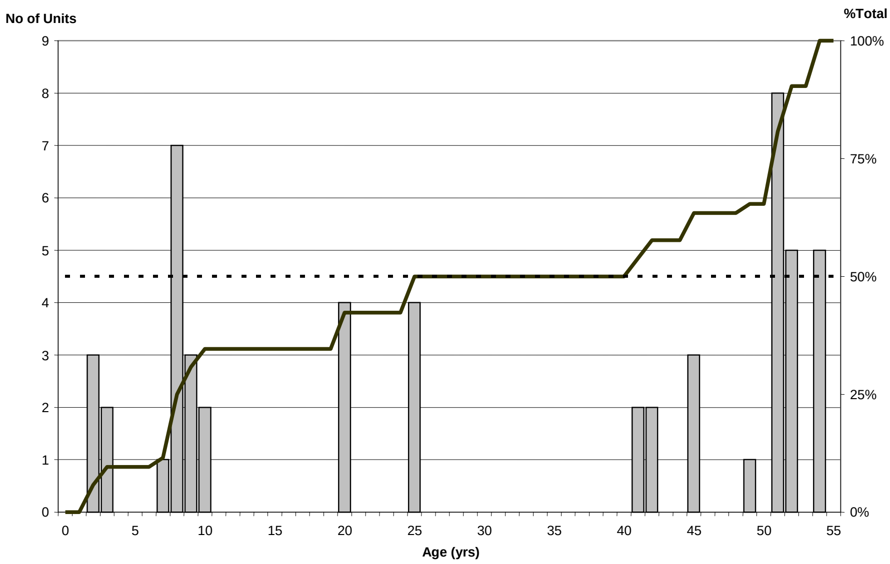

Figure 3.4 – 66 & 33 kV Zone Circuit Breakers Age Profile (Total = 52)

3.3.3 11 kV and 6.6 kV Substation Circuit Breakers

The age profile of 11kV and 6.6kV circuit breakers shown in Figure 3.5 is similar to the age of the zone substations. Half of the circuit breakers are older than the ODV handbook limit of 40 years, the equipment is in good condition and maintenance costs are not significantly higher than for new equipment. The oldest breakers are located at Ward Street substation and are now more than 65 years old. The replacement of these circuit breakers is scheduled within the planning period.

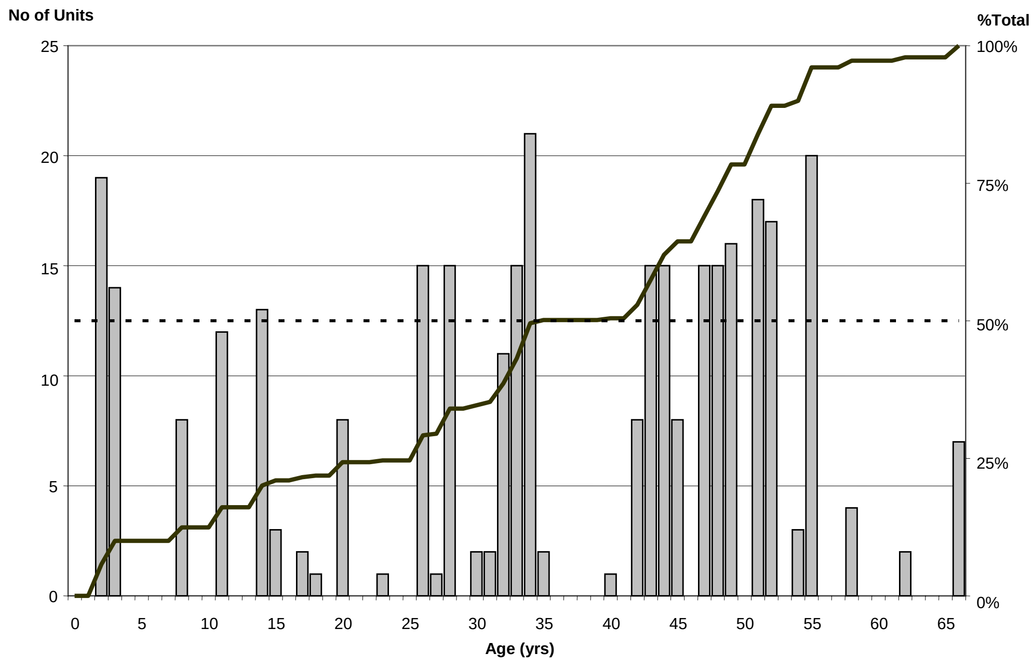

Figure 3.5 – 11 & 6.6 kV Circuit Breakers Age Profile (total = 322)

3.3.4 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 33 kV injection plants in the Central network area are aged 14, 18 and 20 years and replacement is not expected within the planning period.

The age profile of injection plants is shown in Figure 3.6.

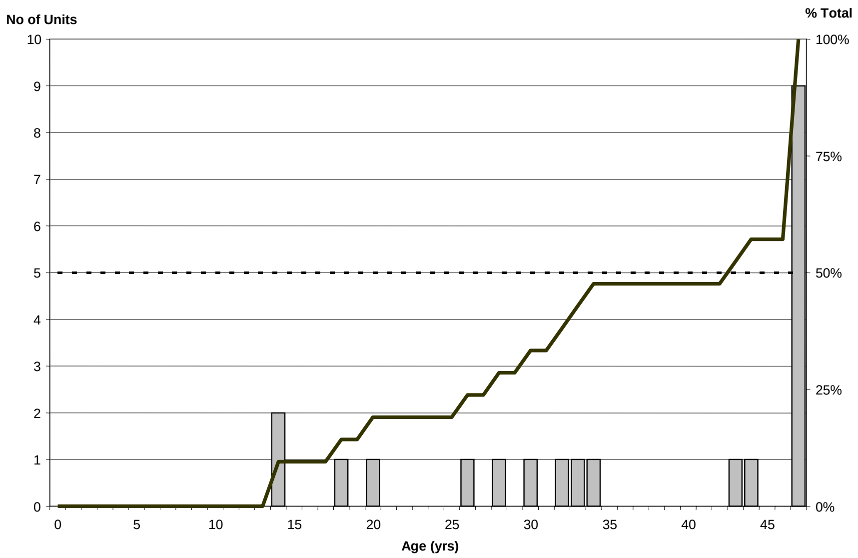

Figure 3.6 – Ripple Injection Equipment Age Profile (Total = 21)

3.3.5 Protection, Local Control and Metering Equipment

With the exception of newer and refurbished substations, the age range of protection relays is generally between 20 and 45 years. As most of these relays are associated with switch-gear their age profiles closely match those shown in Figure 3.5 and experience is that the effective life of protection equipment is as long as the associated breakers.

3.3.6 SCADA Remote Terminal Units

The SCADA remote terminal units in Central date from 2000. In Dunedin the majority of the RTUs were installed in 1987. The Dunedin RTUs have been very reliable but face technical obsolescence due 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.

3.3.7 Other Station 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.

3.3.8 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.

3.4 High Voltage Distribution

HV distribution in the urban area of Dunedin is operated at 6.6 kV and consists of 140 feeders. The Taieri and Peninsula areas are mainly supplied at 11 kV via 25 feeders. Except for supply to two large HV consumers (Otago University and Hillside Workshops) all feeders are operated as radial feeders with interties available to adjacent feeders. 26% are via underground cable with the remaining via wood pole (35%) and concrete pole (39%) overhead lines.

HV distribution in the Central region operates at 11 kV except for 36 km of 6.6 kV in the Clyde and Earnscleugh areas. All feeders are operated as radial feeders with interties to adjacent feeders. However, there are limited intertie facilities between substations. 11% are via underground cable and 89% via overhead line.

3.4.1 11 kV and 6.6 kV Lines

Figure 3.7 details the age profile of HV lines. 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.

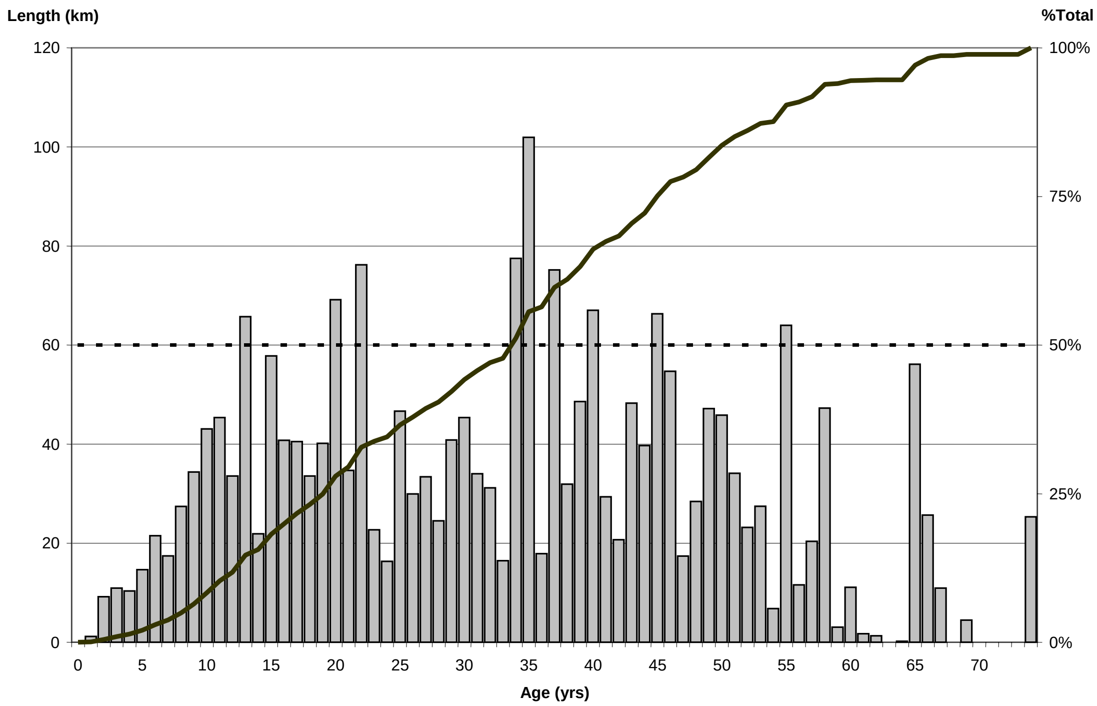

Figure 3.7 – 11 & 6.6 kV Lines Age Profile (Total = 2369 km)

3.4.2 11 kV and 6.6 kV Cables

The age profile of HV cables is shown in Figure 3.8. Deterioration of HV cable has not been a particular problem apart from several kilometres of aluminium sheath paper insulated cable installed in 1954, where sectors 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.

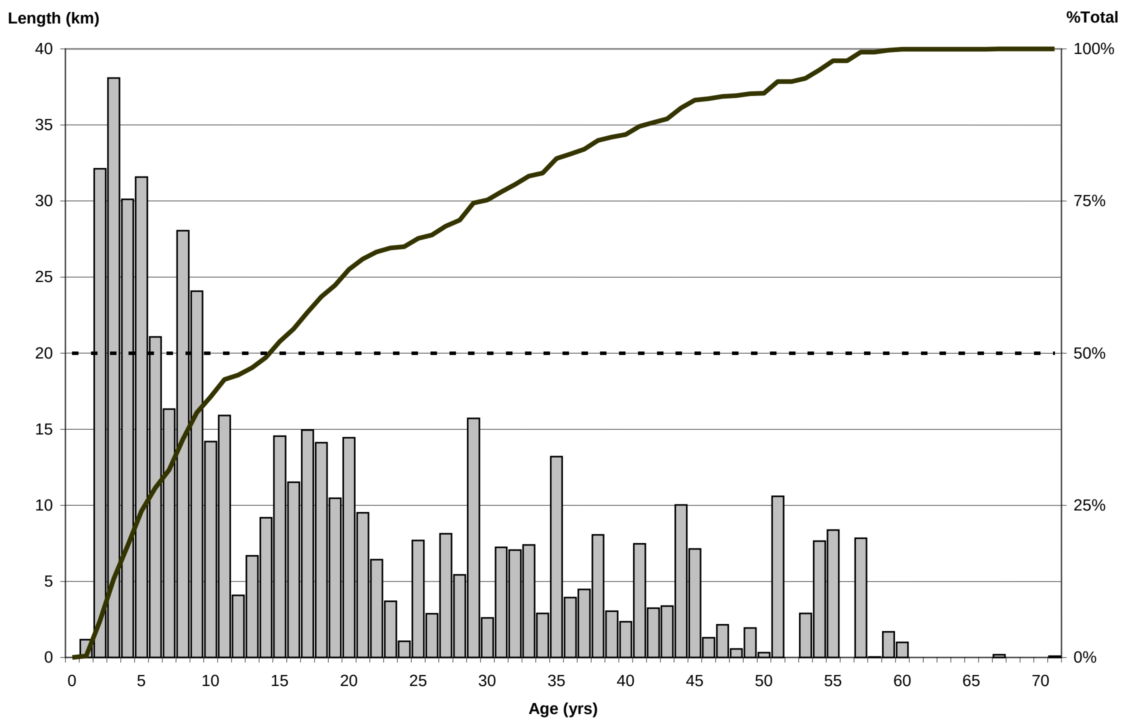

Figure 3.8 – 11 & 6.6 kV Cables Age Profile (Total = 617 km)

3.5 Distribution Substations

Distribution substations comprise the transformer, transformer pad, HV and LV fusing and earth mat. At 1 March 2005, there were 5,626 distribution substations on the Aurora network.

29 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 five per year.

In a 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. An investigation into better protection of assets is ongoing.

3.5.1 Distribution Transformers

Figure 3.9 details the age profile of distribution transformers. 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, routine inspections and monitoring will continue.

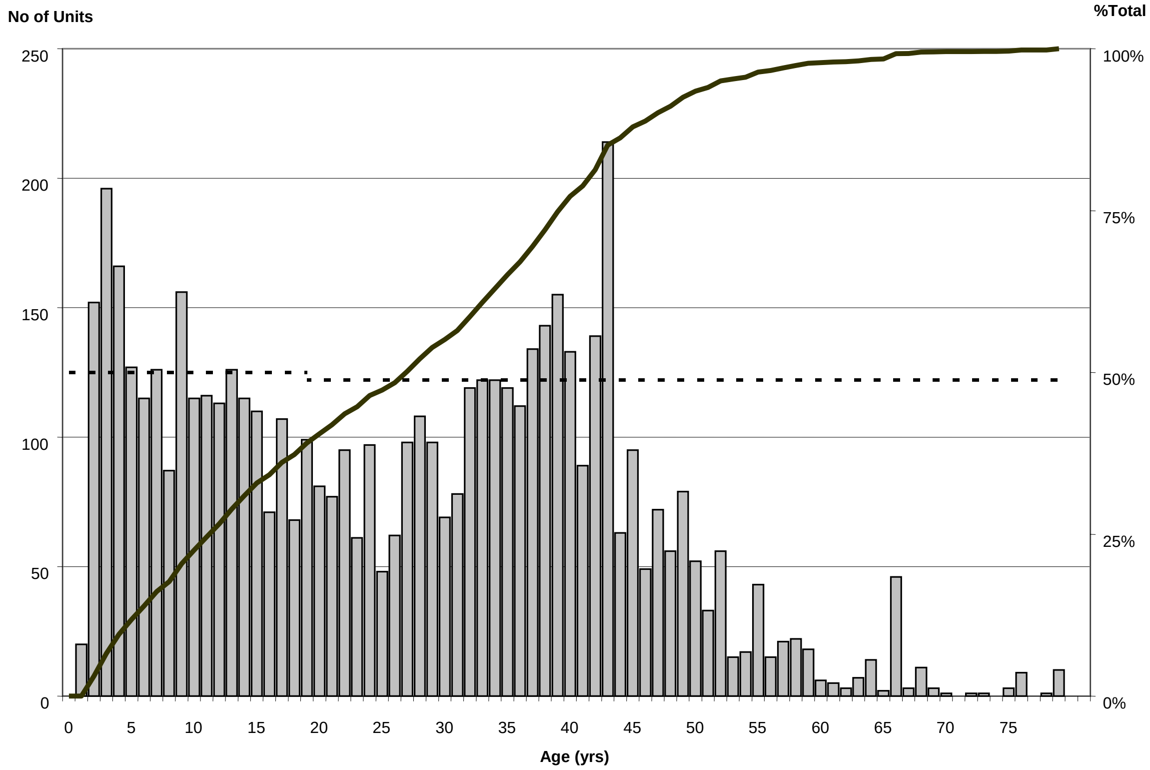

Figure 3.9 – Installed Distribution Transformers Age Profile (Total = 5,626)

3.5.2 HV Regulators

Figure 3.10 details the age profile of regulators. Recently, two units were removed due to high maintenance costs and poor reliability, but the remainder are suitable for further service.

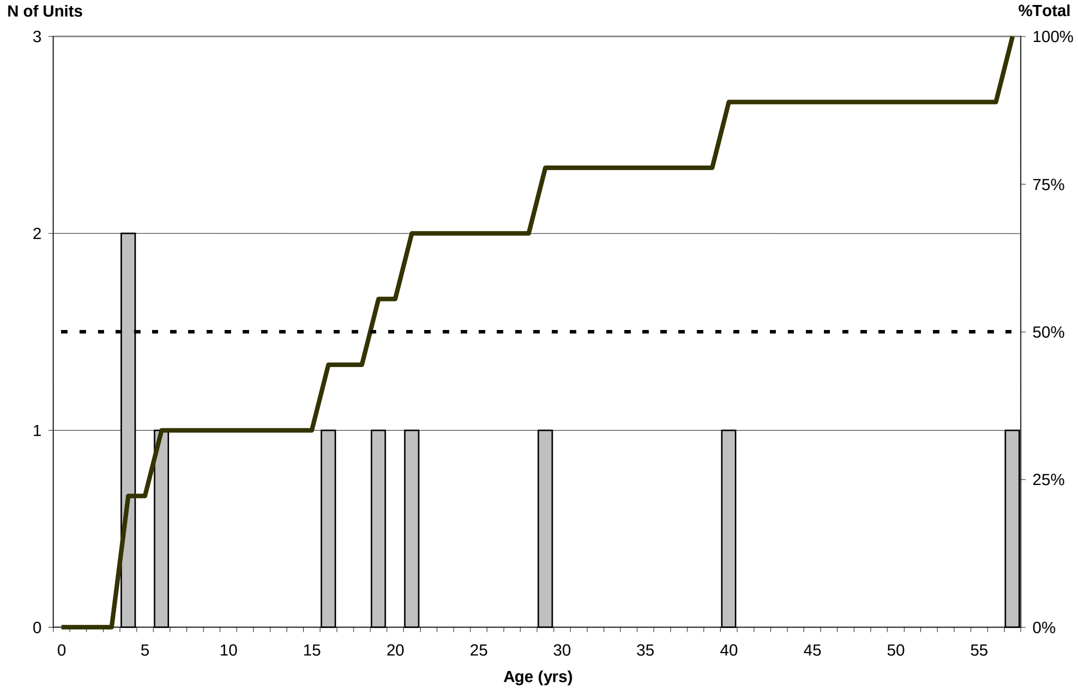

Figure 3.10 – HV Regulators Age Profile (9 Units)

3.5.3 HV Autotransformers

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.

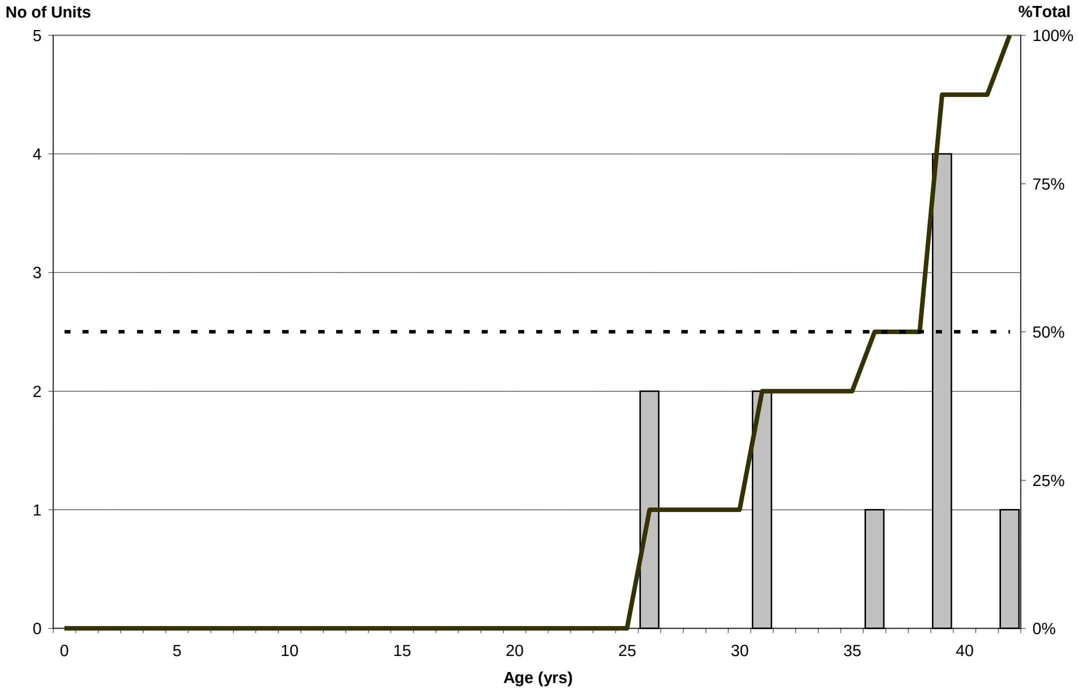

Figure 3.11 – HV Autotransformers Age Profile (10 Units)

3.5.4 HV Distribution Switchgear

The age profile of distribution switchgear is shown in Figure 3.12. 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 at an estimated cost of $160,000.

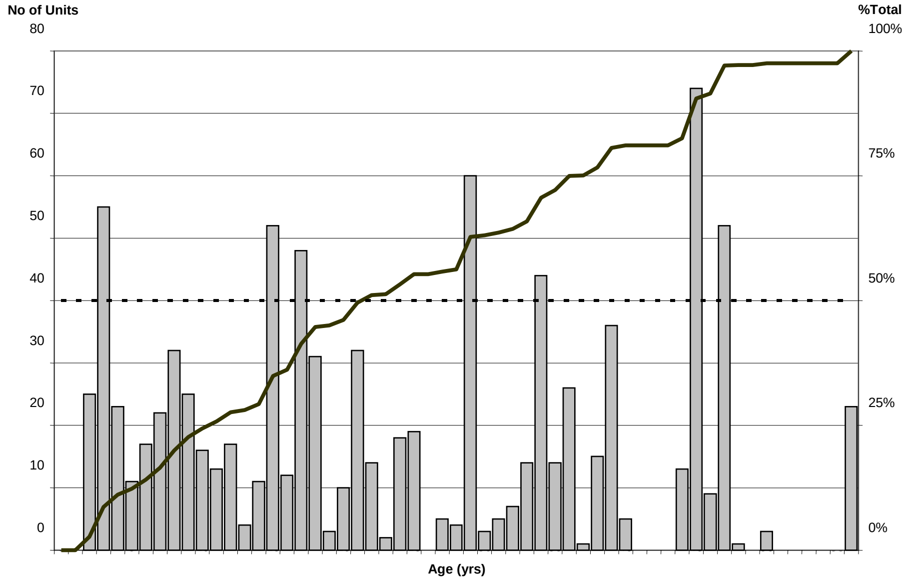

Figure 3.12 – HV Ground Mounted Switchgear Age Profile (Total = 926)

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. 28% of LV distribution is underground with the remaining via wood pole and concrete pole overhead lines.

3.6.1 LV Overhead

Figure 3.13 shows the age profile of overhead LV lines. There are two types of LV overhead on the network, aerial bundled conductor (ABC) and open wire on pin insulators.

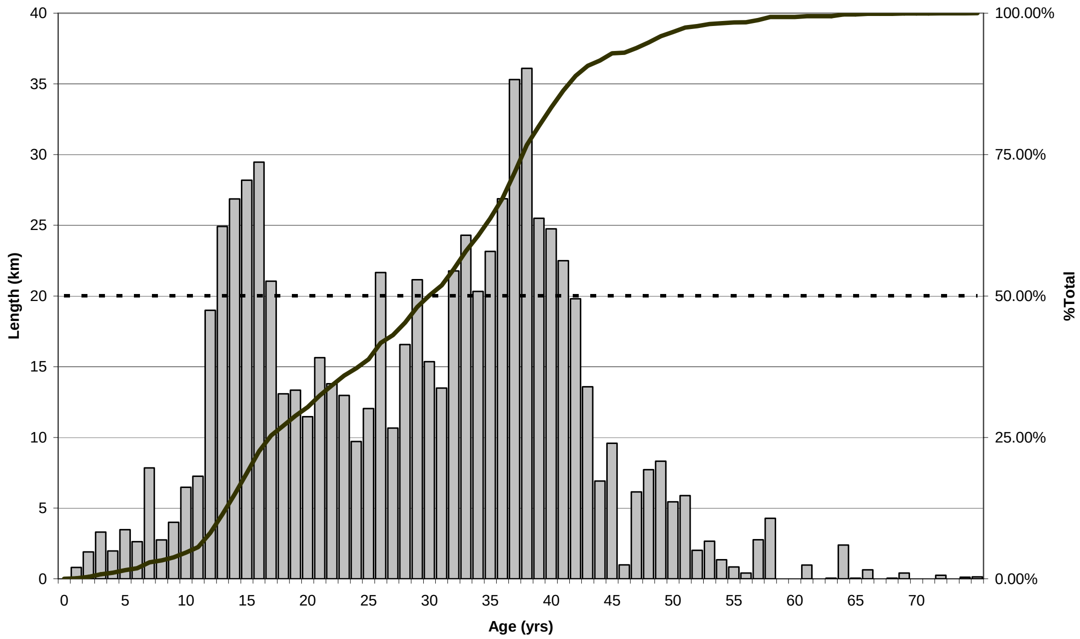

Figure 3.13 – LV Distribution Line Age Profile (Total = 1067.5 km)

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.

3.6.2 LV Underground

Figure 3.14 shows the age profile of the underground cable. Over the network most LV cable is cross linked polyethylene (XLPE). In the Dunedin CBD, paper-insulated lead sheath (PILS) cable has been used.

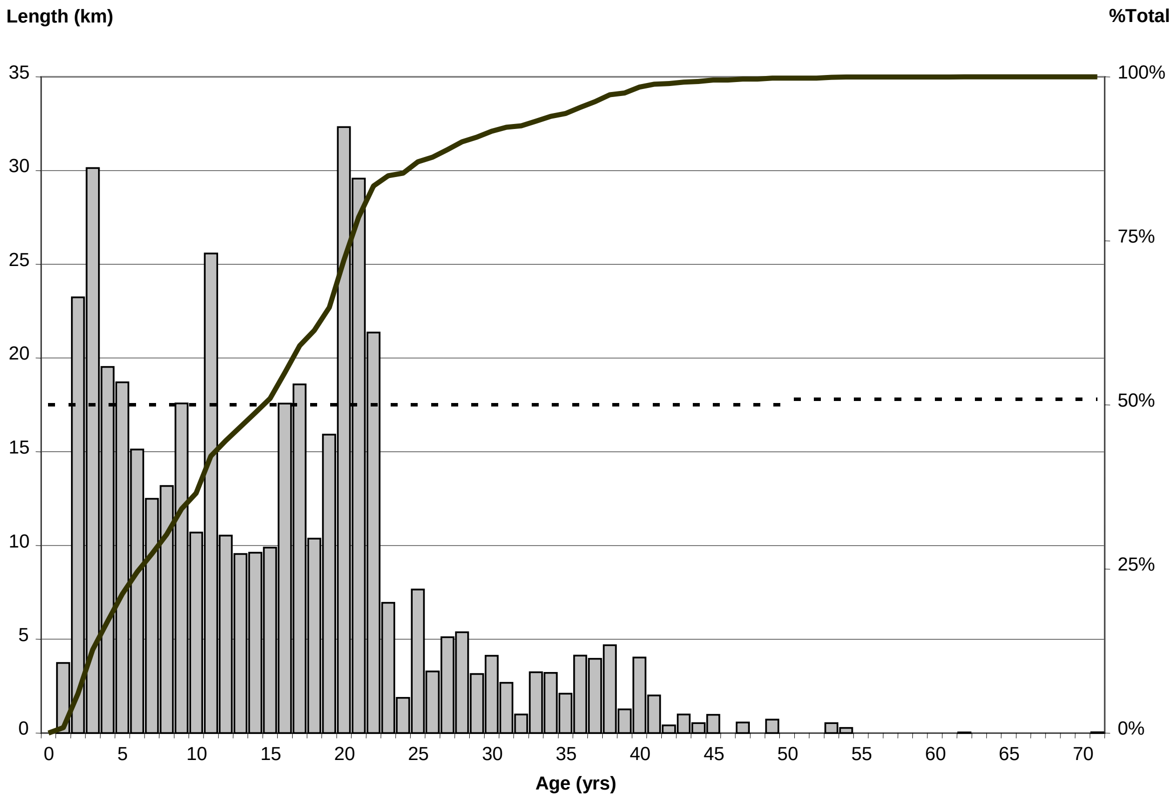

Figure 3.14 – LV Distribution Cable Age Profile (Total = 560.5 km)

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

3.7 Poles

Figure 3.15 details the age profile of poles used for the support of HV and LV circuits. A significant proportion of the 65,000 poles, particularly in the Central region, are of unknown age, and an age has been assigned from conductor age or physical 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 poles are selected based on strict criteria they will have an acceptable life.

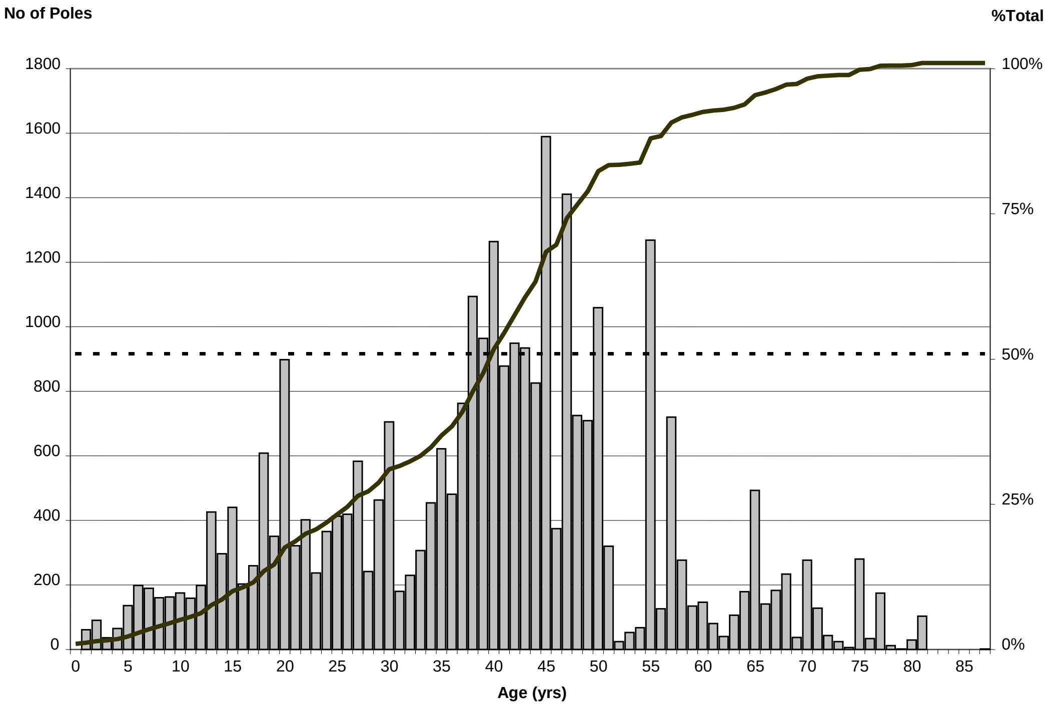

Figure 3.15 – Poles Age Profile (Total = 65,455 poles)

3.8 Communications Systems

The communications systems consist of a mix of technologies, of various ages, which provide bearers for operational speech, protection signalling, operational SCADA and management information.

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

A VHF land mobile network provides an extensive (and exclusive to Aurora and contractors) system essential for operational, phase identification and maintenance activity. The existing system is old and spares are no longer available, but sufficient spares are held for the network to be operated for some years to come. Telecom has announced that it will not replace some devices within the leased circuit network but ready radio replacements are available. The use of existing frequency allocations for the network is guaranteed until 2014 by the Radio Communications Act 1989.

In the Central area, SCADA communication uses a combination of the Aurora owned VHF system in the Upper Clutha area and the Team talk radio link system elsewhere.

In the Dunedin area, with the exception of the Port Chalmers, North East Valley and Taieri Zone substations, all SCADA communications to zone substations is via copper pilot circuits. For other stations, Telecom data circuits are used.

3.9 System Control Equipment

The Aurora network is presently controlled from separate system control centres one in Cromwell for Control of the Central region and the other in Dunedin for control of the Dunedin region. These only operate in work hours, or in response to after-hours callout for significant network faults. Review of the option of moving to a single control centre, and of 24 x 7 operation, continues to indicate that costs exceeds benefits.

The Central region SCADA master station is an Abbey system and was installed in 2000. The Dunedin master station is a Foxboro system that was built in 1998 and is now due for a software and hardware upgrade which is planned for 2005.

4 Service Levels

4.1 Consumer Oriented Reliability, Security and Availability 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 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 per year is shown in Table 4.1, split into underlying and significant event components for the last five years. Significant events are those over 300,000 consumer minutes.

Period End 31 March	2000/01	2001/02	2002/03	2003/04	2004/05
Unplanned					
Underlying	57.7	61.5	55.7	56.6	67.8
Significant Events	4.7	0	12.9	23.4	5.4
Transpower	3.3	13.4	12.1	1.0	0.0
Total Unplanned	**65.7**	**74.9**	**80.7**	**81.0**	**73.2**
Planned					
Underlying	16.7	13.8	20.5	16.3	7.3
Total					
Underlying	74.4	75.3	76.2	72.9	75.1
Significant Events	4.7	0	12.9	23.4	5.4
Transpower	3.3	13.4	12.1	1.0	0.0
Disclosure Total	**82.4**	**88.7**	**101.2**	**97.3**	**80.5**
Other (LV etc)	0.5	0.7	0.8	0.1	0.9
Overall Total	**82.9**	**89.4**	**101.8**	**97.4**	**81.4**

Table 4.1: Network Performance History (SAIDI)

Expected future performance of the HV distribution network is shown in Table 4.2. Analysis of the reliability data for other distribution networks in New Zealand reveals a present average figure of approximately 160 minutes without supply per consumer per year.

As detailed elsewhere, the intention is to hold SAIDI constant, at the levels shown in table 4.2.

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
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 target specific work to the worst performing feeders.

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

Response to a "No Power" Call out
If, as a result of a single LV Connected Customer fuse failure, supply has not been restored (after notification of failure) to the Connected Customer Installation within two hours for the Dunedin Network or three hours[5] for the Central network then Aurora will pay $40 (incl GST) per connection to the Electricity Retailer.

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 (six hours for the Central network) of notification of the failure, then Aurora will pay the Electricity Retailer:

(i) $50 (incl GST) for 8 kVA and 15 kVA Dunedin network connections
(ii) one month's use-of-system charges for Dunedin network larger connections
(iii) $50 (incl GST) per connection for Central network connections.

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

4.2 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and Efficiency of Line Company 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.

[5] The different standards for the Central network result from the Use-of System Agreement held by the incumbent retailer since the network was purchased.

4.3 Justification for Service Levels

4.3.1 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 (section 4.1.3) for the maximum number of outstanding voltage complaints 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.

4.3.2 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*[6] 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, and is both facilitated by technology available today and 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. The survey was commenced in 1999 and is continuous both so that results are less affected by long periods of no 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 Price V Quality Survey						
Results to 31 March	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
Consumers Surveyed	726	4,123	4,220	4,327	4,554	4,634
Response Rate	19%	20%	20%	20%	18%	19%
Responses						
Prefer higher quality	9.6%	8.4%	9.3%	9.3%	7.4%	7.2%
Prefer lower price	90.4%	91.6%	90.7%	90.7%	92.6%	92.8%

Table 4.3 – Price Versus Quality Survey

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

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. 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.

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, and accordingly Aurora will use outside expertise to confirm that probability assessments are appropriate.

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 [7]
Unplanned - Residential	$ 4
Unplanned – Other	$40
Planned – Residential	$ 2
Planned – Other	$20
Planned – Average	$ 4

Table 4.4 – 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 apparent 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.

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.

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

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 unserved 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 unserved load that results.

4.3.3 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), 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[8] 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.

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

4.3.4 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 acceptable. In this regard it is now apparent that for "problem feeders" consumers are more sensitive to frequency of interruptions, and this is receiving specific attention.

4.3.5 Customer Service

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

4.3.6 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.

[8] For the Central Otago assets the agreement was negotiated with Central Electric Ltd and novated to Aurora.

4.3.7 Environmental Responsibility Performance

Many of Aurora's assets are in environmentally sensitive areas. Maintenance programmes include the upkeep of noise-reducing enclosures, the repair and maintenance of oil filled equipment such as transformers and circuit breakers to prevent leakages, 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 ever occurred.

5 Network Development

5.1 Planning Criteria and Assumptions

5.1.1 Planning Process

After winter loadings each year, a 6-year engineering report is produced that:

- details the expansion and upgrading of the network that is necessary/expected over the following 6 years, to accommodate predicted network loadings.
- proposes viable network modifications and replacements to improve network reliability.
- includes cost estimates for budget purposes.

Subsequently, firm costings are obtained before individual projects proceed and special studies are undertaken for complex proposals.

5.1.2 Load Predictions

Load predictions are annually undertaken at HV feeder and zone substation level and are based on recent trends and known consumer developments.

5.1.3 Reliability Criteria

Historically, zone substations with a capacity greater than 3MVA and associated 33kV sub-transmission were designed so that failure of any one item of equipment would not result in any consumers losing supply for more than two hours. For zone substations with a capacity up to 3MVA a single transformer supplied from a single transmission line was provided and restoration often requires fault repairs.

For new developments designs will be determined by the approach described in Section 4.3.2.

5.1.4 Firm Capacity

Firm capacity is the maximum normal load, after any single substation fault, which a zone substation is allowed to carry (equal to the rating of the lowest rated component) plus the load that can be transferred to adjacent zone substations via the HV network.

For the purposes of determining firm load capacity, equipment nominal ratings are increased by cyclic loading factors given in Table 5.1.

Equipment	Cyclic Loading Factor
Transformers ONAN	1.2
Transformers ONAN/OFAF	Manufacturer assigned emergency rating
33kV OH Line	1.1
Airbreak Switchgear	1.0
Current Transformers	1.2
Circuit Breakers	1.0
33 kV Cables	1.15 [9]

Table 5.1 – Cyclic Loading Factors

[9] Applies to direct buried cables only and assumes one of the paralleled buried cables is not carrying load.

5.1.5 Equipment Standards

Aurora has developed the following in-house standards which are regularly reviewed:

- NS2.1 – Network Earthing
- NS2.2 – Construction of Pole Substations
- NS2.6 – Underground Reticulation Design & Construction
- NS2.7 – Ground & Pad Mounted Substations
- NS2.8 – Overhead Line Construction
- NS2.10 – Distribution Transformer & Substation Specifications
- Southern Power Companies Overhead Line Design Manual, Revision 4.
- QP1105 – Distribution Transformers
- QP1106 – HV Distribution Switchgear
- QP1107 – Treated Softwood Poles
- QP1204 – High Voltage Cable Testing
- QP1510 – Transformer Loading Guide
- QP1720 – Distributed Generation less than 10 kW
- QP1901 – System Planning Procedures
- QP2117 – Application of Lightning Arresters

5.1.6 Economic Analysis

For all development proposal evaluations the net present value (NPV) is calculated. In calculating the NPV the cost of electrical losses (presently valued at $0.075 per kWh), maintenance costs and consumer outage costs are considered. When considering projects to improve supply reliability or comparing project proposals with different predicted reliability then the costs of non-supply are used as detailed in Table 4.4.

5.1.7 Environmental Considerations

The major environmental impacts of electricity distribution projects are:

- visual Impact
- noise
- containment of insulating oil.

Other factors that may need consideration in specific situations are

- the effect on wildlife, for example - overhead line bird strikes
- requirement for subsequent vegetation control in the vicinity of overhead lines.

5.2 Demand Forecasts, Network Configuration Analysis and Reliability Assessments

Demand forecasting is based upon the historical trend modified by specific areas of load growth as notified by developers and/or population growth predictions. Feeder development plans based upon these forecasted loads and reliability requirements are then detailed in the six-year development plan and annual budgets.

5.3 Policies on Non-asset Solutions, Redeployment and Upgrade of Existing Assets, Acquisition of New Assets, Adoption of New Technology, and Disposal of Existing Assets

As an alternative to new capital expenditure in meeting load growth in specific areas, options involving improved utilisation of existing assets are a major consideration. Reconfiguration of the HV distribution network to maximise load diversity between various classes of load and varying load factors plays an important part in the 6 year development planning process.

The policy for disposal of assets is based upon economic life, when the evaluation of the relevant costs of maintenance and reliability exceeds the replacement cost. Replacement cost in this instance takes into consideration the full life span cost and improved technology of the replacement plant.

As policy, Aurora also provides guidelines to assist prospective owners of distributed generation to connect into Aurora's network. This information may be found at http://www.electricity.co.nz/download/DGdoc.pdf

5.4 Analysis of Options Available and Decisions Taken re Service Levels

System development proposals are formulated to satisfy the requirements of notified or anticipated load growth or to extend the system capability in minimising the effects of system faults. When solutions are proposed to cater for new identified load, the development objectives of the 6 year development plan must also be considered and satisfied. Due consideration is also given to meeting the objectives of improved asset utilisation, improved system reliability and greater system flexibility to permit repairs/ restoration of the system, so minimising customer outage times following a system fault. See Section 4.2 for cost of non-supply details.

Development proposals also extend to operational matters to improve system performance and reliability.

6 Description and Identification of Maintenance Policies, Programmes and Actions for each Asset Group including Associated Expenditure Projections

6.1 Maintenance Policies

6.1.1 General

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

Assets deteriorate with age and, if not maintained, would eventually fail. Effective maintenance management involves balancing the cost of repairs and replacements against the consequences of failure. Premature or too frequent repairs and replacement unnecessarily increase maintenance costs, while repairs delayed too long can also increase costs because of excessive deterioration in the interim, as well as increasing the risk of failure. Age-based maintenance and replacement, while conservative in engineering terms, tends to lead to unnecessarily high maintenance (including replacement) costs through premature replacements and through a proportion of repairs being redundant. Aurora's maintenance strategy is based on careful monitoring of asset condition to balance the risks

Maintenance work comprises two main elements:

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

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 defects, once detected 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 replaced based on age or other generic criteria; they are kept in service until such time as their continued maintenance is uneconomic or until they pose a safety or reliability risk.

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

- routine inspection and tests 8%
- special inspections 2%
- planned refurbishment 36%
- planned replacement 13%
- planned repairs 20%
- fault repairs 21%

6.1.2 Inspections, Servicing and Testing

Around 8% of Aurora's maintenance expenditure is for periodic inspections, patrols, servicing and tests. This work is largely undertaken to ensure that defects or emerging risks are identified so that corrective work can be carried out. 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. These procedures define the frequency of servicing/inspections etc 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 5 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 of breaker 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).

6.1.3 Planned Repairs, Refurbishment and Replacement

Around 69% of maintenance expenditure is for planned repairs, refurbishment and replacement of unserviceable assets. About half of this involves asset refurbishment or replacement programmes and repair programmes involving repairs 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 repairs (e.g. individual insulators) many of which arise out of specific defects found within the year.

6.1.4 Fault Repairs

Fault repairs are carried out directly following an equipment failure, in order to restore service, and accounts for 21% of maintenance expenditure. This work may or may not involve permanent repair 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 repair work, it may be that the faulted unit is replaced by a serviceable unit, e.g. a spare transformer unit. The faulted unit can then be repaired later, or a decision may be taken to dispose of it if repairs cannot be justified.

6.1.5 Maintenance Planning Principles

Plans for asset maintenance are developed from an assessment of asset condition. Aurora continues to define composite maintenance management systems which will contain detailed condition information on all assets. The Plan is based on the knowledge of present asset managers and maintenance inspectors, supported by information from available data records.

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

6.1.6 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.

6.1.7 Circuit Breaker Replacement

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

6.1.8 Power Transformer and Distribution Transformer Repairs and Refurbishment

Similar modelling as has been used for circuit breakers is utilised for assessing replacement/maintenance 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 repair each year. This analysis includes winding, core and internal connection repairs, oil refurbishment, painting and radiator replacement.

6.2 Maintenance Programmes

6.2.1 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.

6.2.2 Overhead Lines

Annual drive-by patrols are carried out on the overhead 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 overcurrent fault of unknown source.

6.2.3 Protection Pilots

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

6.2.4 Zone Substations

33kV Transformers and Tapchangers

The transformers are relatively trouble free apart from occasional oil leaks from bushings or radiators. Although the age profile is getting high these transformers have not been heavily loaded during their life and only one replacement is considered necessary within the planning period for the Berwick Transformer due to age, inadequate tapping range and a non-standard vector group. The Roxburgh Hydro transformer will be decommissioned within the planning period mainly to reduce maintenance and because substation resources can be more effectively utilised elsewhere.

Tapchangers are routinely overhauled after a set number of operations, dependent on type. 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 0.1mg KOH/g acid level, good breakdown resistance and low moisture content. The oil is tested annually for these factors.

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.

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

Civil Works General

This category provides for general building upgrading and repairs, the completion of seismic strengthening works identified and expenditure on grounds and security fencing and systems. It also includes “earthing systems” monitoring and maintenance.

Corstorphine, South City and Ward St 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 to implement a condition based maintenance program. Painting of outdoor circuit breakers is undertaken on a rolling basis with major repaints at 10 year intervals.

Twenty-six 33kV circuit breakers are now over 40 years old and some will require replacement within the next 10 years. These substations include Alexandra, Berwick, Ward St, Neville St, Outram and Mosgiel.

One hundred and eighty 6.6 and 11kV circuit breakers are now over 40 years old and some will require replacement within the next 10 years. These substations include Cromwell, Dalefield, Earnscleugh, Ettrick, Frankton, Green Island, Halfway Bush, Mosgiel, Neville Street, Port Chalmers, Remarkables, Roxburgh, Roxburgh Hydro, Smith St and Ward St. Port Chalmers, Cromwell and Frankton are scheduled for replacement within the planning period. Other sites are being monitored.

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

Ripple Injection Plant
Routine maintenance of ripple injection plant consists mainly of contactor checks and the dressing or replacement of contacts. Most motor-generator sets have had their bearings replaced in recent years and no further replacements are considered necessary within 5 years. The solid state coupling cells are virtually maintenance free.

Low frequency injection at the Dunedin GXP is forecast (subject to economic viability and retailer commitment) for 2006-2009 in two separate stages allowing the retirement of the motor generation sets currently (1050Hz) in use. Low frequency receivers will be installed prior to decommissioning the motor generation sets.

The 33kV injection equipment in the Central network area is solid state, relatively new, and has minimal maintenance requirements.

There are approximately 65 distribution substations in the Central Otago network which have pilot wire control installed between 1970 and 1988. These have been suffering from decreased reliability, and it has been standard practice after failure of these units to replace 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 replacement of smaller units initiated by age and larger units by discharge tests.

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

At 12 monthly intervals, all SCADA transmit and receive levels are checked, recorded and adjusted if necessary and power supplies 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 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 as required at regulation intervals and depend 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.

6.2.5 HV and LV Lines and Cables

At present, lines are inspected approximately every two years, but this will be reviewed with the new Hazards from Trees regulations coming into effect from 1 July 2005. A précis of these regulations can be seen on the Aurora website.

6.2.6 Inspections

HV and LV Lines
A rolling inspection of approximately 600km 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. All remaining maintenance is either fault repairs or planned repairs.

Upgrading work has been carried out over recent years on the LV distribution system in the Queenstown CBD where many obsolete link pillars have been replaced with modern units which provide a safer and more flexible system. This work has now been extended to Wanaka and Alexandra areas.

Pole Replacements
Hardwood poles are presently being replaced at the rate of about 1.5% per year. The pole age profile implies that the replacement rate will gradually increase over the next 20 years and then decline again.

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 6 yearly intervals.

Overhead Conductor and Cross-arm Replacement
Approximately 2 to 5 kilometres of LV conductor and cross-arm replacement is programmed each year, depending on condition assessments. As well as condition based replacement work, upgrading is necessary due to the installation of new substations and/or local load growth and voltage complaints.

11kV and 6.6kV Overhead Conductor and Crossarm Replacement
Approximately 5 kilometres of HV conductor and cross-arm replacement is programmed each year in both the Dunedin and Central areas and it is expected that this level of refurbishment will be sufficient for the next 10 years.

6.2.7 Distribution Substations

Transformers
Expenditure on transformer maintenance is expected to increase as large numbers of transformers reach their normal economic life. In the Central Otago area, some 29 pedestal mounted transformers are to be replaced. They have been identified a being a latent safety concern. Presently, 4-5 per year are planned to be replaced with ground mounted substations.

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 100 kVA 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. However, some of these circuit breakers supply critical substations, and are reaching the end of their physical life. These will be replaced within the plan and expenditure on these will gradually reduce over the plan period. Two Statter VL switches have failed recently, and as a result two more will be replaced in strategic locations.

6.2.8 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.

A service contract for the maintenance of the SCADA software will commence in July 2005.

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.

It is expected that the asset operating and maintenance 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	**05/06**	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Sub-transmission	494	500	507	514	521	528	535	542	549	556
Zone Substations	1,204	1,220	1,236	1,252	1,268	1,284	1,301	1,318	1,335	1,352
System Control	108	109	110	112	113	114	116	117	118	119
HV & LV Lines and Cables	7,660	7,760	7,861	7,963	8,067	8,172	8,278	8,385	8,444	8,553
Distribution Substations	1,350	1,367	1,385	1,403	1,421	1,440	1,458	1,478	1,497	1,516
Total Expenditure	**10,816**	**10,956**	**1,1099**	**11,244**	**11,390**	**11,538**	**11,688**	**11,840**	**11,994**	**12,096**

Table 6.1 – Maintenance Expenditure Summary ($000)

6.3 Description and Identification of Network Development Programmes and Actions to be Taken Including Associated Expenditure Projections

Enhancement and development plans are established from:

- specific requests regarding large load increments
- network analysis regarding (minor) load increases
- improved technology offering lower costs or improved service
- new regulatory requirements.

Projections of future network loads are used to determine the timing of enhancement and development. Past and projected annual energy input to the system are shown in Figure 6.1 and peak system demands are shown in Figure 6.2. Also shown are the estimated forward projections of both values, utilised for system development projections.

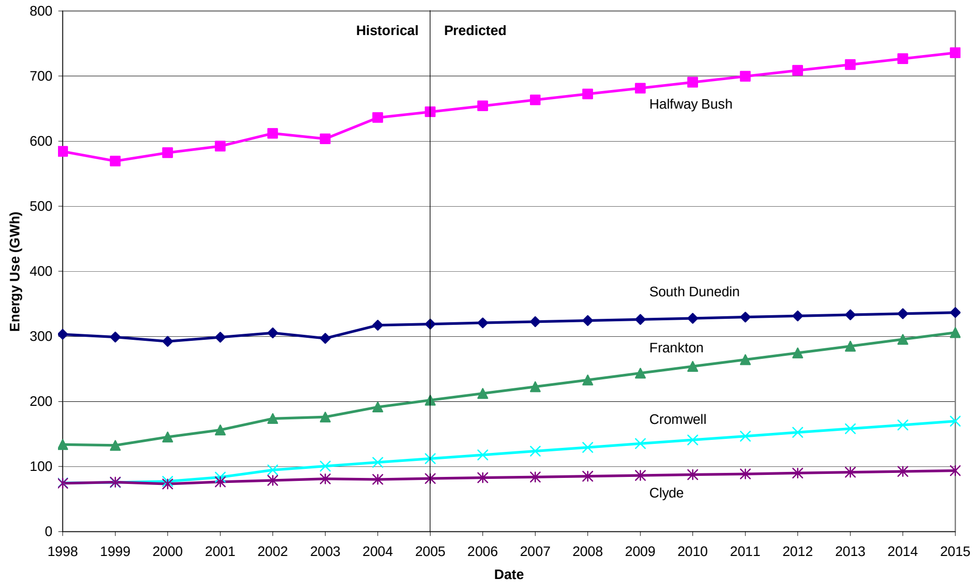

Figure 6.1 – Growth in GXP Energy Inputs

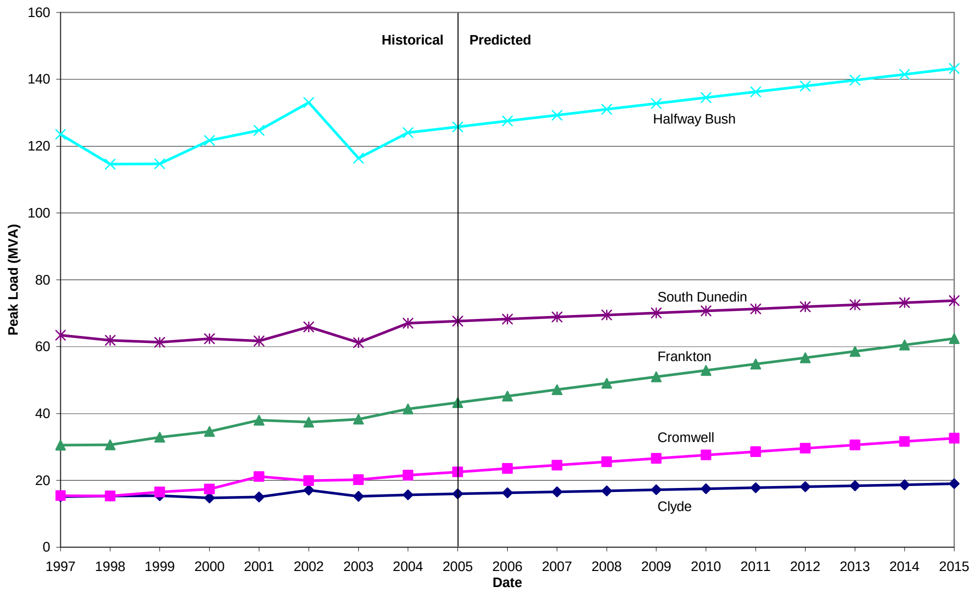

Figure 6.2 – Growth in GXP Peak Demands

The reduction in some maximum demands for 2003 was largely due to an electricity energy shortage and hence saving campaign during the early winter.

The growth in demand at the Frankton and Cromwell GXPs reflects increasing winter demand - in particular, the three to four weeks school and University holiday period in June/July. Last winter, aggressive load control was used with retailer agreement, to keep the peak loads within nominated demand levels.

An active demand management programme is conducted with major consumers. While it assists them to reduce their demands and thus line charges, it does not materially affect asset utilisation for the majority of Aurora assets.

Overall, GWh delivered is expected to increase at the rate of 2.0% and demand by 1.9%. See Table 6.2.

Network Forecasts	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
Energy Input (GWh) (2.0%)	1359	1388	1416	1444	1472	1501	1529	1557	1585	1613
Maximum Demand (MW) (1.9%)	275	281	286	292	297	303	309	314	320	325
Distribution Transformer Capacity (MVA) (2%)	785	801	817	833	849	866	883	901	919	937

Table 6.2 – Network Demand Forecast

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15
New Customers	7,100	7,100	6,100	5,900	5,800	5,800	5,600	5,600	5,600	5,600
Local Growth including renewals	1,900	2,000	2,040	2,081	2,122	2,122	2,264	2,421	2,593	2,782
System Development including SCADA	179	210	214	218	223	683	228	234	239	245
Closeburn Zone Sub	300									
Glenorchy Zone Sub	550									
Berwick Zone Sub		300								
Morven Ferry Sub					480					
Port Chalmers 11 kV Switchgear	560									
Cromwell 11 kV Switchgear	700									
Jacks Point Zone Sub		1,000								
Tarras Zone Sub			500							
Undergrounding	1,468	1,483	1,598	2,003	2,028	2,053	2,078	2,104	2,130	2,156
Ripple Injection		600		600			700			
Subtransmission & Zone Substations			1,978	2,000	2,533	2,924	3,119	4,051	4,281	4,505
Total	12,757	12,693	12,430	12,802	13,186	13,582	13,990	14,409	14,842	15,287

Table 6.3 – Capital Expenditure Forecast

- New Consumers: development required to meet the local area demand dictated by new customer requirements.
- Local Growth: 11kV development out of zone substations to meet general local area increase in demand and meet statutory voltage requirements.
- System Development is defined as 33kV subtransmission, zone substations, and protection (i.e. SCADA) plus special (rare, costly and specifically defined 11kV) projects.

- Undergrounding includes $100,000 of works to other utilities - mainly Telecom.
- The Closeburn and Glenorchy zone substations are required to cater for load growth north of Queenstown.
- The Berwick transformer and 33kV switchgear replacement is planned as the existing equipment is believed to be reaching the end of its economic life.
- The Morven Ferry substation is planned to cater for future growth in the Gibbston area and provide for off-loading of Arrowtown.
- The Port Chalmers 11kV switchgear replacement resulted from an analysis of equipment reliability and SAIDI concerns. The analysis as per section 4.3.2 proved that it was economic to replace this equipment.
- The Cromwell 11kV switchgear has reached its load limit and needs to be replaced.
- The Jacks Point zone substation is planned to service development in this area.
- Ripple injection projects are subject to further review.
- A new 6.6/11kV substation is required in the Tarras area to provide standby capacity for the Queensberry substation. Load in this area has grown rapidly due to pumping for irrigation.

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 a policy does not relate to risk management then it isn't necessary. If it does relate 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

Generic Risk Area	Sub-Category	Policy Reference
Employment	Employee relations	▪ Standard Conditions of Employment policy ▪ Individual Employment Agreement template
	Health and safety	▪ Health and Safety policy
	Maintenance of work skill capability	
Environmental Protection		
Financial Management	Interest rate exposure	
	Liquidity	
	Re-financing	
	Defalcation	
	Fraud	▪ Fraud and Other Similar Irregularities policy ▪ Protected Disclosures 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. Over the previous five years four external reviews have been commissioned.

- August 2000. Assessment of network risks in the Central Otago region focussing on the 33 kV system and zone substations
- November 2001. Assessment of network risks in the Dunedin region focussing on the 33 kV 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.

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.

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

- May 2005. All ground-mounted transformers were assessed for risk of being hit by a vehicle and a resulting oil leak getting into a water way. A small number of transformers have been identified as high risk and mitigation options are currently being considered.

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 MW	n-1 Security
Halfway Bush	144	44	133	No[10]
South Dunedin	100	-	64	Yes
Clyde	60	17	18	Yes
Frankton	38	2	40	No
Cromwell	30	4	20	Yes

Table 7.1 – Injection Security

Transpower has been asked to prepare a proposal to upgrade the Frankton GXP capacity by Winter 2007.

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 best economic engineering solution.

[10] 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 will 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 their 33kV generation up to 44MW, and up to 5MW would be transferred to the South Dunedin GXP via the 6.6kV network.

7.1.5 Safety

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

The Health and Safety in Employment 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 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 will be complying with the new tree trimming regulations as a result of the Electricity (Hazards from Trees) Regulations 2003 which come into effect on 1 July 2005. At this stage, the costs of compliance are not yet certain.

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 documented 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 Centre which is staffed during normal business hours. After hours, a standby roster is 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 Manual 778. This is currently being updated to include major double contingency events.

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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.

Category	04-05 Plan (Minutes/connection)	Actual (Minutes/connection)
Unplanned		
Underlying	64	68
Significant Events	10	5
Transpower	1	0
	75	73
Planned		
Underlying	15	7
TOTAL	90	80

Table 8.1 – Expected Vs Actual SAIDI Minutes 2004-2005

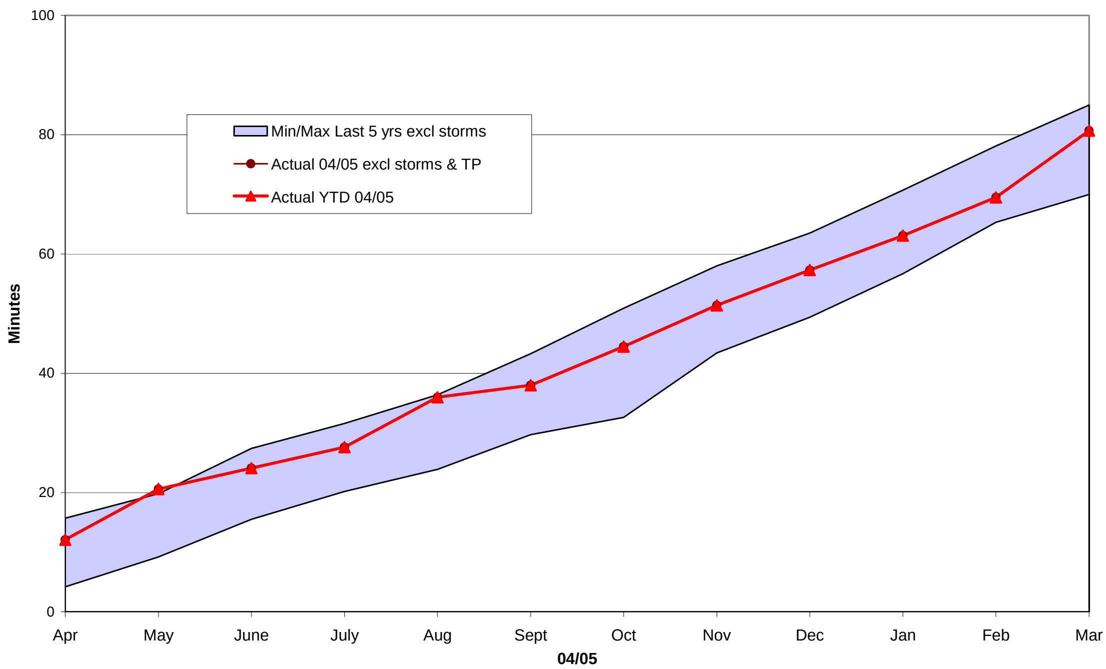

Figure 8.1 – Cumulative Total Interruptions
(Average Minutes without Supply per Consumer per Annum)

However, for unplanned interruptions, the “underlying” pattern was 4 minutes worse than budget. Significant events were 50% better than budget and there were no Transpower interruptions, resulting in the total being 2.7% below budget.

For planned interruptions, while the level of new 11 kV construction experienced in Central has not changed significantly, the number of planned interruptions has been reduced as contractors find ways to minimize the cost penalties of interruptions as described in section 4.3.2.

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.

8.2 Review of Financial Performance

8.2.1 Operating and Maintenance

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.
- Some distribution transformer earth testing in the Central area has not been completed as planned due to resource constraints. This has now been addressed and the uncompleted work will be caught up in the coming year along with the programmed testing.
- Thermal imaging of all zone substations' equipment and major distribution assets was carried out. Repairs as necessary have been completed.
- Routine zone substation equipment condition monitoring has mostly been completed as planned, however higher loads than usual during autumn restricted access to some plant. This has required some work to be deferred until next spring/summer and one zone substation's testing programme has been brought forward as it is not load constrained until later in the year.
- On the sub-transmission system, there were more gas leaks on the Dunedin 33kV gas cables than expected; however this was partly offset by their being less faults in the Central area than anticipated.
- There have been two major SCADA failures during the year which required the manufacturer's representatives from Australia to be on site to undertake repairs.
- As detailed in 8.2, overall system reliability was better than target.

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

Category	Budget $000	Actual $000	Variance	
Distribution Substation	1,226	1,089	-137	-11%
HV and LV Lines and Cables	7,500	7,277	-223	-3%
Zone Substations	1,146	1,036	-110	-10%
Sub Transmission	770	785	15	2%
System Control	36	65	29	81%
Total	10,677	10,251	-426	-4%

Table 8.1 – Operating and Maintenance Expenditure Budget Compared to Actual

8.2.2 Capital

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

New connections were above budget, mainly in Central, by 24%. However, this is a downturn compared to the previous year ($8.9 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.

$165,000 of this were two “one off” safety related projects, being the replacement of SOHI switchgear in conjunction with third parties.

Another major project was the under-building of the line south of Closeburn at a cost of $308,000. It was originally envisaged that this would be split over two financial years but once resource consents were gained and not appealed the work could proceed in the current year.

The Closeburn and Glenorchy substations were delayed a year as it proved possible to do so.

The emergency generator projects were under-spent because of slower progress than planned. The Dunedin generator will be replaced by September 2005. A generator is in place at the Cromwell office.

Category	2004/05 Actual ($000)	2004/05 Budget ($000)	Variance
New Connections	7,300	5,900	24%
Localised Growth	2,850	2,000	43%
System Development including SCADA	200	210	-5%
Undergrounding Projects	1,527	1,527	0%
Closeburn Zone Substation	50	500	-90%
Glenorchy Zone Substation	0	550	-100%
Emergency Generators	160	200	-20%
Cromwell MEN	50	50	0%
Total	12,137	10,937	11%

Table 8.2 – Comparison of Actual Capital Expenditure with Plan

8.3 Gap Analysis and Identification of Improvement Initiatives

Both planned and unplanned maintenance activities are constantly analysed to monitor performance trends and to evolve both maintenance practices and replacement policies.

Changes implemented since the last asset management plan include:

- extension of maintenance intervals for batteries
- extended maintenance intervals for some brands of tap changers
- planned replacement of older types of distribution oil switchgear as a result of measured deterioration of insulation values.

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. Recently identified improvements have included:

- Port Chalmers 11 kV switchboard replacement
- Omakau reclosers –supplying the Lauder and St Bathans areas
- extending SCADA control to the Gibbston and Makarora reclosers
- re-sectionalising Alexandra feeder 168 near the Manuherikia River.