AURORA ENERGY LTD

ASSET MANAGEMENT PLAN No 11

April 2004-March 2014

Revised: 30 June 2004

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

TABLE OF CONTENTS

F O R E W O R D

This is the eleventh Network Asset Management Plan for the distribution network owned by Aurora Energy Ltd and covers the 10 year period from 1 April 2004. It documents existing and projected network asset conditions and the likely or intended asset management programmes, based on the present understanding of customer requirements. It is not an approved programme for specific work; rather the programmes and projects are indicative. In some cases plans will be subject to user discussion and/or funding, while in all cases they are subject to financial approvals.

D I S C L A I M E R

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

1 Executive Summary

1.1 Purpose

The purpose of this document is to describe, in accordance with the Electricity (Information Disclosure) Regulation 1999 and the Electricity (Information Disclosure) Amendment Regulations 2000, the asset management objectives plans and systems adopted by Aurora Energy Ltd for the line 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 completed 30 June 2004 and relates to the 2004-2014 period and represents an evolution of the annual Asset Management Plan published for the Dunedin network since 1993.

1.3 Asset Management Systems and Information

Aurora Energy Ltd, herein known as 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 it continues to review its Information Systems Strategic Plan 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.

1.4 Network and Asset Description

The network assets comprise the types and quantities summarised in Table 1.1, located in the Dunedin and Central Otago areas. Their condition is detailed in Section 3.

Approximately 4.1% (by Depreciated Replacement Cost (DRC)) of existing assets have been “optimised” out of Aurora’s revenue base (Appendix 1). This represents the degree of asset stranding due to changes in either consumer requirements or technology since these assets were installed.

TYPES AND QUANTITIES OF INSTALLED ASSETS 2002

Asset Category	RC	%	Quantity
Sub-transmission	$31,637,626	10%	591 km
Zone Substations	$73,134,017	23%	36
System Control	$2,899,050	1%	176
HV Distribution	$87,787,755	28%	2,738 km
Voltage Regulators	$590,000	0.3%	6
Auto Transformers 6.6/11kV	$480,000	0.2%	10
Distribution Switchgear	$18,309,780	6%	6,260
Distribution Substations	$6,598,500	2%	5,163
Distribution Transformers	$37,009,465	12%	5,201
LV Distribution	$46,961,938	15%	1,371 km
Service Connections	$5,751,700	2%	73,507
Street Lighting Distribution	$6,692,000	2%	976 km
Total	$317,851,832		

Table 1.1 Types and Quantities of Assets

1.5 Service Level Objectives

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

Table 1.2

Function	Objective
Network Performance	Average of no more than 90 minutes without supply per customer per year.
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.
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.

* The different standards for the Central network result from the Use-of-System Agreement in existence when the network was purchased.

1.6 Maintenance Policies and Projected Expenditures

As a result of considerable refurbishment work carried out on both overhead lines and substation equipment in the last decade in the Dunedin area and the last six in the Central Otago area, the network is in reasonably good condition. Improved knowledge and analysis of maintenance trends has resulted 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 are determined. Current expectations are that the expenditure projections shown below are necessary to meet agreed service targets.

Maintenance Expenditure Summary $000

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Sub-transmission	487	494	500	507	514	521	528	535	542	544
Zone Substations	1,189	1,204	1,220	1,236	1,252	1,268	1,284	1,301	1318	1335
System Control	107	108	109	110	112	113	114	116	116	118
HV & LV Lines & Cables	7,562	7,660	7,760	7,861	7,963	8,067	8,172	8,278	8385	8494
Distribution Sub-stations	1,332	1,350	1,367	1,385	1,403	1,421	1,440	1,458	1478	1497
Total Expenditure	10,677	10,816	10,956	11,099	11,244	11,390	11,538	11,688	11840	11,994

Capital Expenditure Forecast $000

	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
New Customers	5,900	5,900	5,900	5,900	4,700	3,980	4,059	4,140	4,200	4,200
Local Growth including renewals	2,000	1,900	2,000	2,040	2,081	2,122	2,165	2,208	2,240	2,240
System Development including Scada	210	150	210	214	218	223	227	232	235	235
Closeburn Zone Sub	500									
Glenorchy Zone Sub	550									
Berwick Zone Sub		340								
Morven Ferry Road			400							
Cromwell MEN	50									
Undergrounding	1,350	1,350	1,350	1,496	1,720	1,720	1,720	1,720	1,720	1,720
Generators	200								-	
Ripple Injection		600			600					
Total	10,760	10,240	9,860	9,650	9,319	8,045	8,171	8,300	8,395	8,395

Most of the capital associated with “New Customers” results directly from applications for supply. This growth will cause future “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 5.6.

New Customer investment is funded mainly by the customers via capital contributions. The current boom in Central Otago is forecast to taper off in the 07/08 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 line charges back into the community for undergrounding works on a one-to-one basis. Funds were, in effect, 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 Arrowtown in conjunction with the QLDC watermains contracts, substantial funding of projects in this area will not occur until 2007/08. The Central Otago District Council just begun to take advantage of this policy with 2 small scale projects being constructed in 2003.

The economics of replacing the zone substation ripple injection plants with GXP injection plant in Dunedin are still being assessed. If this was not to take place the existing ripple injection units in the Dunedin zone substations would require significant upgrading in the years 2007 – 2010.

1.7 Statement of Opportunities

This section describes opportunities for demand side management or embedded generation opportunities that may alleviate present network congestion. In previous plans, Aurora has described of 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 has subsequently announced proposals for up to 16MW generation on the Lake Hawea outlet.

Opportunities now exist in alleviating the load at the Frankton GXP. Parties interested in investing in either generation or demand-side alternatives are invited to contact *DELTA*. Joint venture options are a possibility.

1.8 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 plus the cost of non-supply. Likewise, asset replacement is determined when the NPV of the new asset exceeds the NPV of non replacement.

1.9 Risk Assessment

Risk assessment and risk management strategies focus on three specific 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 the Asset Management Quality System detail operational and planning policies and guidelines for dealing with each of these risk management areas.

1.10 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 2003. When judged on the combination of low price (average distribution charge/kWh delivered) and high quality (SAIDI), the Dunedin network was in the 'upper quartile' of the 29 distribution businesses. Accordingly, Aurora believes that the targets set below are appropriate given the results of itsr continual survey (see section 4.3). Price is expressed as cents/kWh delivered. Quality of supply is represented by SAIDI. The data is from Information Disclosures.

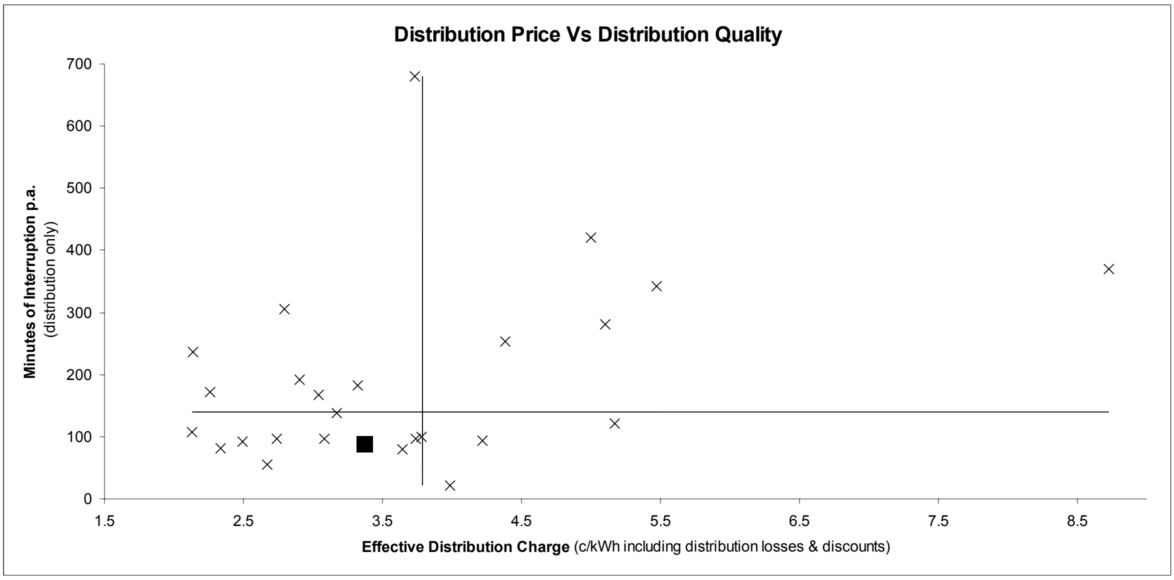


Figure 1.1 Price-Quality Matrix

2 Background and Objectives

2.1 Planning Periods Adopted and Interaction with Other Corporate Plans

Aurora has four levels of corporate planning; a strategic plan, an asset management plan, a six year development plan and an annual budget. Aurora revises its Strategic Plan annually, prior to determination of budgets.

This plan covers the period from 1 April 2004 to 31 March 2014 and represents an evolution of the annual Asset Management Plan published for the Dunedin network since 1993.

Aurora adopts a rolling six-year network-development plan annually, which proposes specific asset developments to provide for anticipated load growth and appropriate asset replacement.

2.2 Stakeholder Interests

Stakeholders are those parties with a direct interest in Aurora's network asset management policies and practices. The principal stakeholders and their interests are as follows:

Table 2.1

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
Property Developers	New-connection policies Timely network expansion
Shareholder	Adequate, stable and secure return on investment Good corporate citizenship

Stakeholder	Interest
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

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.

2.4 Details of Asset Management Systems and Processes

The asset management information systems are built on the ESRI geographic information system. This system 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.

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 achieved ISO 9002 certification for its Asset Management Quality System. Successive audits by the Telarc registration authority have seen that ISO certification maintained by *DELTA*.

3 Assets

3.1 Description of Asset Configuration, Categories, Age and Condition

A schedule of assets by asset category appears as Table 1.1

The Aurora network covers two geographical regions, the Dunedin region and Central Otago region .

3.1.1 Network Injection

The Dunedin network area is supplied from two Transpower grid exit points at South Dunedin and Halfway Bush and at Berwick from TrustPower's Waipori power scheme. The Central Otago network area consists of three zones with no electrical interconnection, each supplied from Transpower grid exit points at Clyde, Cromwell and Frankton, and from Pioneer Generation power schemes as detailed below.

Injection Point	Asset Owner	Voltage kV	GWh pa
1. Halfway Bush	Transpower NZ Ltd	33	527
2. Berwick	TrustPower NZ Ltd	33	76
			603
3. South Dunedin	Transpower NZ Ltd	33	297
4. Frankton	Transpower NZ Ltd	33	164
5. Wye Creek	Pioneer Generation Ltd	33	8
6. Glenorchy	Pioneer Generation Ltd	11	4
			176
7. Roxburgh	Pioneer Generation Ltd	33	73
8. Fraser	Pioneer Generation Ltd	33	8
9. Clyde	Transpower NZ Ltd	33	14
			95
10. Cromwell	Transpower NZ Ltd	33	74
11. Roaring Meg	Pioneer Generation Ltd	33	27
			101

Table 3.1 Network and Injection Points

3.1.2 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. The North East Valley zone substation is teed off the Port Chalmers zone substation feeders.

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 17 zone substations in the Central Otago network area. The six zone substations supplying significant urban areas each have a pair of transformers and at least two 33kV supply routes. The 12 smaller zone substations (3 MVA and below) have a single transformer and in most cases a single 33 kV supply. Details are shown in Table 3.2 below.

Table 3.2 Sub Transmission

	Grid Exit Point	Sub-Transmission	Zone Substation	n-1 * Security	AUFLS *
1	Clyde	Single line from Roxburgh	Ettrick	N	N
2	Clyde	Via 2 lines to Alexandra	Roxburgh	Y	N
3	Clyde	Tee off one 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	Queensbury	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 the Queenstown to Frankton lines	Frankton	Y	N
17	Frankton	1 line from Frankton GXP	Remarkables	N	1
18	Halfway Bush	Via Taieri sub-transmission lines	Berwick	Y	N
19	Halfway Bush	Oil Cable via Mosgiel and Taieri lines	East Taieri	Y	N
20	Halfway Bush	2 x line	Green Island	Y	2
21	Halfway Bush	2 x solid cable	Halfway Bush	Y	N
22	Halfway Bush	2 x solid cable	Kaikorai Valley	Y	N
23	Halfway Bush	Via Taieri sub-transmission line	Mosgiel	Y	N
24	Halfway Bush	2x gas cable	Neville Street	Y	1
25	Halfway Bush	2 x line and cable tee off Port Chalmers lines	North East Valley	Y	N
26	Halfway Bush	Via Taieri sub-transmission lines	Outram	Y	N
27	Halfway Bush	2 x line	Port Chalmers	Y	N

	Grid Exit Point	Sub-Transmission	Zone Substation	n-1 * Security	AUFLS *
28	Halfway Bush	2 x gas cable	Smith Street	Y	N
29	Halfway Bush	2 x gas cable	Ward Street	Y	N
30	Halfway Bush	2 x gas cable	Willowbank	Y	1
31	South Dunedin	2 x gas cable	Andersons Bay	Y	1
32	South Dunedin	2 x oil cable	Corstorphine	Y	1
33	South Dunedin	2 x oil cable	North City	Y	N
34	South Dunedin	2 x oil cable	South City	Y	N
35	South Dunedin	2 x oil cable	St Kilda	Y	2

* n-1 - The ability to service full load with one transformer being out of service.
*AUFLS - Automatic Under Frequency Load Shedding.

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 s

3.1.3 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 will 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 & 33kV) is shown in Figure 3.1 and is based on conductor age.

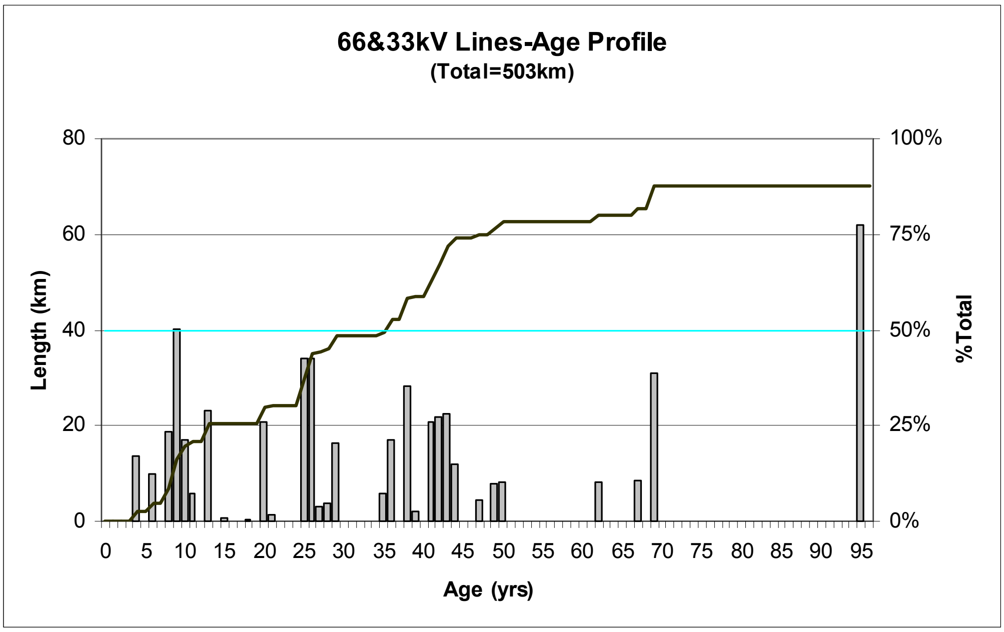


Figure 3.1

3.1.4 33kV Cables

Following the Auckland CBD crisis in February 1998, an independent investigation was undertaken to confirm the condition of 33 kV cables and maintenance practices employed for those cables. The report confirmed that most of the 33kV cables are in good condition.

Subsequent to the above report, partial discharge testing is now being applied to the 33kV cables. This new, condition based monitoring will provide useful information concerning the health of the cable insulation and will be used to monitor a section of cable in Arrowtown that is known to have moisture ingress.

The age profile of 33kV cables is shown in Figure 3.2

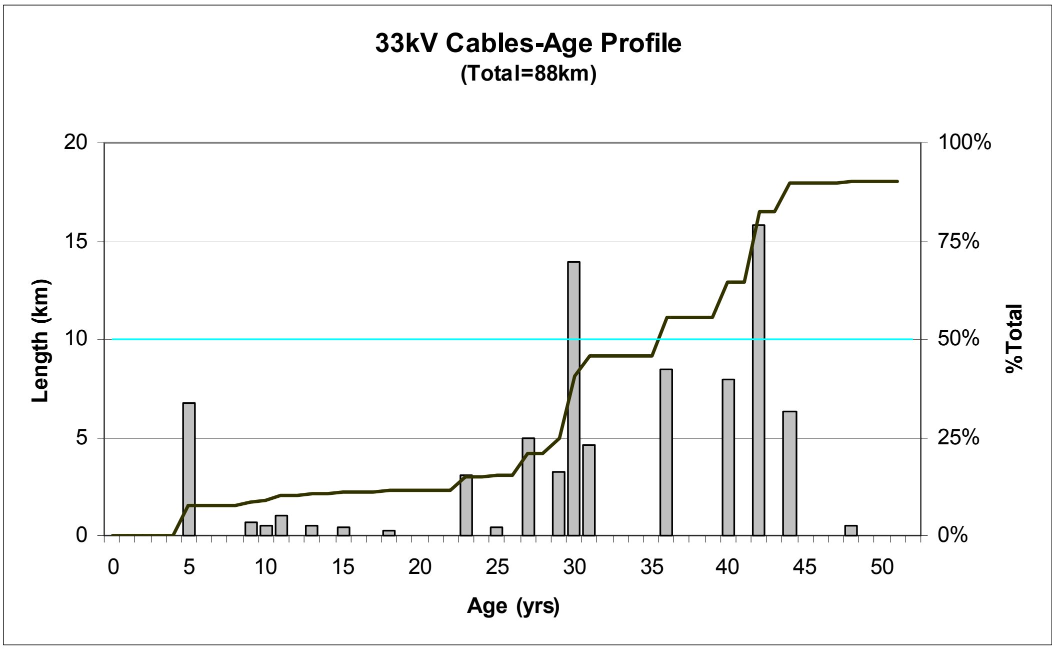


Figure 3.2

The 33kV gas insulated cables from Halfway Bush grid exit point to Neville Street zone substation had experienced sufficient failures 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 then be justified. Partial discharge testing of a back up cable confirmed that the deferment of capital works remains appropriate. Further analysis of the frequency of gas cable failures is planned.

3.1.5 Zone Substations

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

\\delta1\EngiServ\Eng\6 Year Development Plan\Excel\[6 Year development tables 2004_Rev2.xls]6Yr Plan

				Historical Demands								Predicted Future Demands							
Zone Substation	**Transformer MVA**	**Firm Load**	**n-1**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**Previous 6 yr Growth %/yr**	**Predicted Growth %/yr**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2009 U.F. Firm**	**2009 UF (n-1)**
Alexandra	7.5/15+7.5/15	15	15	10.5	9.9	10	10.8	11.1	10	0.5%	2.0%	10.7	10.9	11.2	11.4	11.6	11.8	79%	79%
Anderson's Bay	15 + 15	22.8	18	13.7	14	14	15.8	15.5	13.5	1.0%	0.0%	14.8	14.8	14.8	14.8	14.8	14.8	65%	82%
Arrowtown	5 + 5	7.5	6	4.5	3.7	5.6	6	5.6	6.3	6.8%	6%	6.7	7.1	7.6	5.5	5.9	6.2	83%	**104%**
Berwick	0.9 +0.9	2	0	1	0.85	1.2	0.9	1.2	1.2	4.2%	0.0%	1.2	1.2	1.2	1.2	1.2	1.2	59%	**N/A**
Clyde/Earnscleugh	4 +2	4.8	2.4	4.1	4	4.2	4.1	4.7	4.1	1.3%	2.0%	4.4	4.5	4.6	4.7	4.8	4.9	**102%**	**204%**
Corstorphine	12/24 + 12/24	29	23	12.2	11.5	12	13	13.5	12.2	1.6%	0.0%	12.9	12.9	12.9	12.9	12.9	12.9	44%	56%
Cromwell	5/10 + 7.5	7.0	6.4	5.3	5.4	6	6.2	6	6.6	3.7%	2.5%	6.7	6.9	7.0	7.2	7.4	7.6	**108%**	**119%**
Dalefield	3	3.6	0	3.3	3.2	3.4	3	3	3	-2.4%	2.5%	0.8	0.9	0.9	0.9	0.9	1.0	27%	**N/A**
Earnscleagh	2	2.4	0																**N/A**
East Taieri	12/24 + 12/24	20	22	11.5	12.2	10.9	13.4	14.7	13.6	4.1%	1.0%	14.3	14.5	14.6	14.8	14.9	15.1	75%	68%
Ettrick	3	3.6	0	*	*	1.8	1.6	2	2	5.0%	2.0%	2.0	2.1	2.1	2.2	2.2	2.3	63%	**N/A**
Fernhill	7.5/10+7.5/10	10	0	+	4	4.6	5.1	4.8	5.2	4.9%	4%	5.5	5.7	5.9	6.2	6.4	6.7	67%	**N/A**
Frankton	7.5/15 +5/10	12	10	5	5.6	6.6	7.7	7.9	7.8	7.5%	6.0%	8.8	10.2	10.8	11.4	12.1	12.8	**107%**	**128%**
Green Island	15 + 15	24	18	12	11	12	13	12.5	12.9	2.2%	0.0%	13.0	13.0	13.0	13.0	13.0	13.0	54%	72%
Halfway Bush	15 + 15	24	18	12.1	12	12	14	14.1	12.2	1.9%	0.5%	13.4	13.5	13.6	13.6	13.7	13.8	57%	76%
Kaikorai Val.	12/24 + 12/24	28	22	12.1	10	9	11.8	9	9	-5.0%	0.0%	9.0	9.0	9.0	9.0	9.0	9.0	32%	41%
Maungawera	3	3.6	0	*	*	2.1	1.9	2.3	1.9	-1.0%	3.0%	2.1	2.1	2.2	2.3	2.3	2.4	67%	**N/A**
Mosgiel	10 + 10	13	12	13.1	13.4	15	14	12	11	-3.8%	2.0%	12.2	12.4	12.7	12.9	13.2	13.5	**104%**	**112%**
Neville St	15 + 15	23	18	13.1	13	12.4	14.2	13.6	13	0.7%	0.0%	13.4	13.4	13.4	13.4	13.4	13.4	58%	75%
North City	14/28 +14/28	34	28	19.5	19	19.4	21	21.1	21.1	2.1%	1.0%	21.5	21.7	22.0	22.2	22.4	22.6	67%	81%
North East Val.	9/18 +12/24	23.9	18	10.5	11.5	11.3	11.3	11.4	10.22	-0.4%	0.5%	11.0	11.0	11.1	11.1	11.2	11.2	47%	62%
Omakau	3	3.6	0	1.5	1.5	1.1	1.6	1.54	1.7	2.9%	0.0%	1.6	1.6	1.6	1.6	1.6	1.6	45%	**N/A**
Outram	3 + 3	3.6	3.6	2.1	2.4	2.3	3	2.5	2.5	3.2%	0.5%	2.7	2.7	2.7	2.7	2.7	2.8	77%	77%
Port Chalmers	7.7 +7.5	11.4	9	7.6	7.2	7	8	7.5	7.6	0.7%	1.0%	7.7	7.8	7.9	7.9	8.0	8.1	71%	90%
Queensberry	3	3.6	0	*	*	0.45	0.45	0.56	0.8	15.7%	6.0%	0.8	0.8	0.9	0.9	1.0	1.0	29%	**N/A**
Queenstown	10/20 +10/20	23	20	18.7	15.5	16.7	18.8	18.3	18	1.1%	6.0%	19.3	19.4	20.6	21.8	23.1	24.5	**107%**	**123%**
Remarkables	1	1.2	0	0.6	0.7	0.7	0.8	0.75	0.8	4.4%	0.0%	0.8							**N/A**
Roxburgh	1.5 +1.5	3.6	1.8	2.4	2.4	2.6	2.4	2.9	1.9	-1.5%	0.5%	2.4	2.4	2.4	2.4	2.4	2.4	67%	**N/A**
Roxburgh Hydro	1.8	2.16	0	0.9	0.9	1.1	0.8	0.63	0.85	-5.1%	0.0%	0.8	0.8	0.8	0.8	0.8	0.8	35%	**N/A**
Smith St	15 + 15	24	18	14.8	17	16.8	18.2	19	16	2.1%	2.0%	18.3	18.6	19.0	19.4	19.8	20.2	84%	**112%**
South City	9/18 +9/18	24	18	13.1	11.8	12	13	13	11.8	-0.4%	0.0%	12.3	12.3	12.3	12.3	12.3	12.3	51%	68%
St Kilda	12/24 + 12/24	29	23	15	15	15	15	14.7	14.7	-0.5%	0.0%	14.7	14.7	14.7	14.7	14.7	14.7	51%	64%
Wanaka	12/24 +12/24	25	23	8.9	9	10.6	11.9	11.4	11.5	5.1%	7%	12.9	13.8	14.8	15.8	17.0	18.1	73%	79%
Ward St	15 + 15	24	18	11.2	10	11.8	11.6	11	10.4	-0.3%	0.0%	10.9	10.9	10.9	10.9	10.9	10.9	45%	61%
Willowbank	15 + 15	24	18	12.6	12	13	14	12.2	12.1	-0.2%	1.0%	12.7	12.8	13.0	13.1	13.2	13.4	55.7%	74.2%
Closeburn	1	1.2	0							0.0%	5.0%		0.4	0.4	0.4	0.4	0.4	37%	NA
Glenorchy	1	1.2	0							0.0%	5.0%		0.6	0.6	0.6	0.7	0.7	55%	NA
Morven Ferry	3	3.6	0							0.0%	5.0%			2.5	2.6	2.8	2.8	76%	NA
Coronet Peak	5	6	0							0.0%	3.0%	3.2	3.3	3.4	3.5	3.6	3.7	62%	NA

Table 3.3

Comment to Table 3.3

Earnscleugh is a standby substation for the frost fighting season.

3.1.6 Power Transformers

The age profile of zone substation transformers is shown in Figure 3.3. Transformers subject to prudent monitoring and maintenance practices should last for at least 60 years. Of the six 70+ year old units, four including a spare are single phase transformers at Roxburgh Hydro and two are at Berwick. The two Berwick transformers and voltage regulator are scheduled to be replaced with a single 3MVA transformer in 2005, and the Roxburgh Hydro transformers decommisioned in 2005.

The use of dissolved gas analysis (DGA) has shown that Queenstown Transformer T1 requires monitoring of 6 monthly intervals.

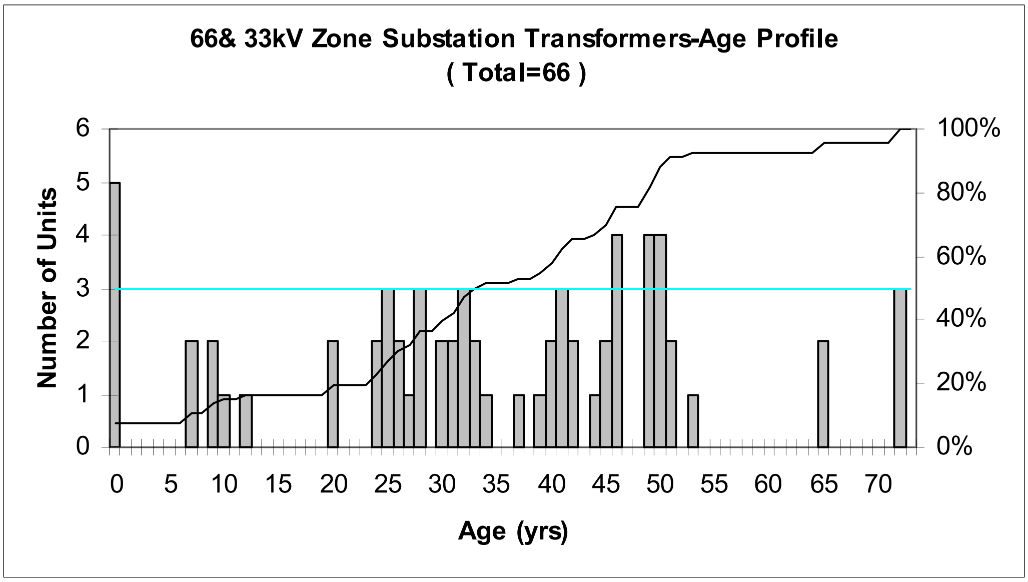


Figure 3.3

The age profile of the 66 & 33kV switchgear is shown in Figure 3.4.

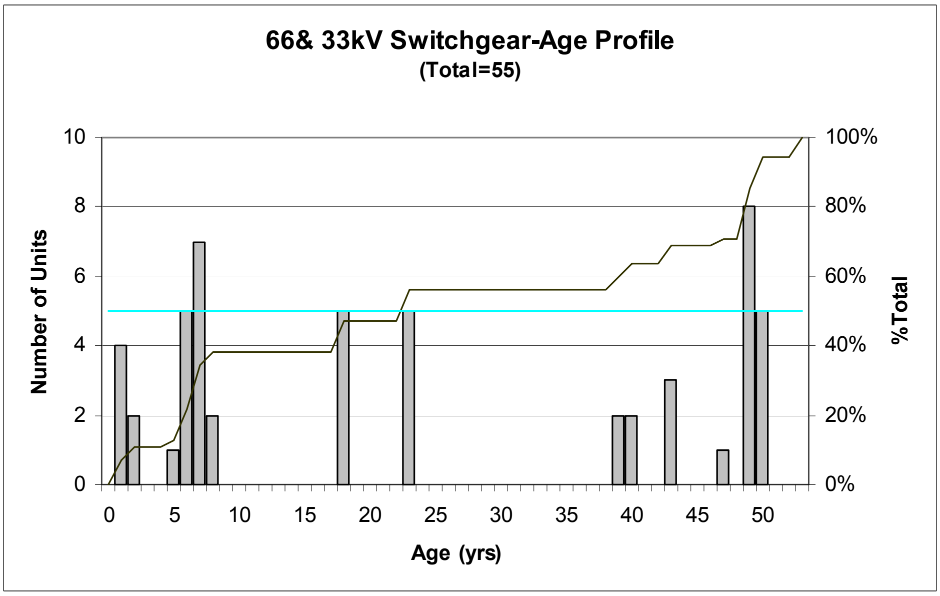


Figure 3.4

11kV and 6.6kV Substation Switchgear

The age profile of 11kV and 6.6kV switchgear (Figure 3.5) is representative of the age of the zone substations. Half of the switchgear is 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 switches are located at Ward Street substation and are now more than 50 years old. It is expected that planning for the replacement of these circuit breakers will begin to enter the Planning Period in one or two year's time, i.e. there should be another 10 years life.

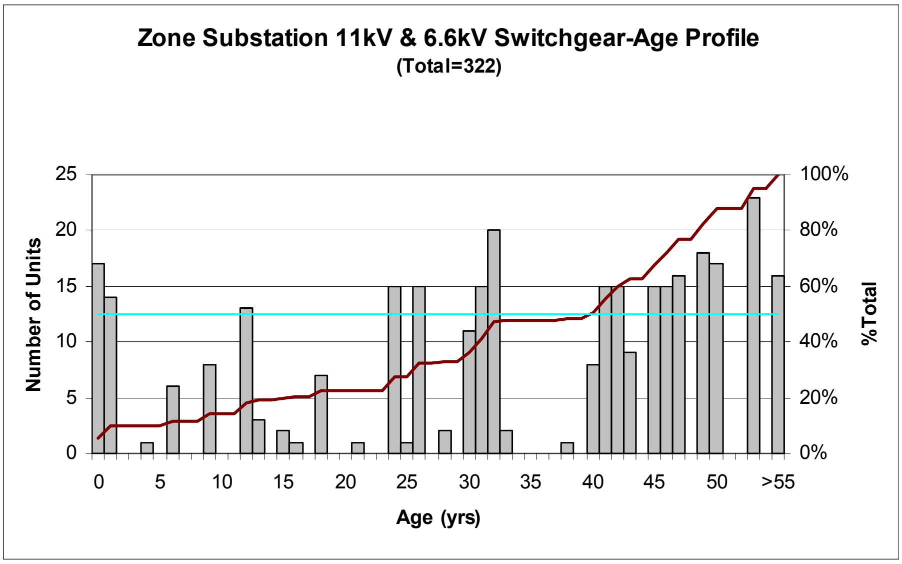


Figure 3.5

Ripple Injection Equipment

In the Dunedin network area the 11kV and 6.6kV injection equipment at each zone substation dates from 1958 or from the date of construction of the substation if later. Replacement of the plants with 33kV injection is presently under consideration but plans are yet to be confirmed. The 33 kV injection plants in the Central sub-transmission zones are aged 11, 14 and 17 years and replacement is well beyond the planning horizon.

The age profile of the injection equipment is shown in Figure 3.6.

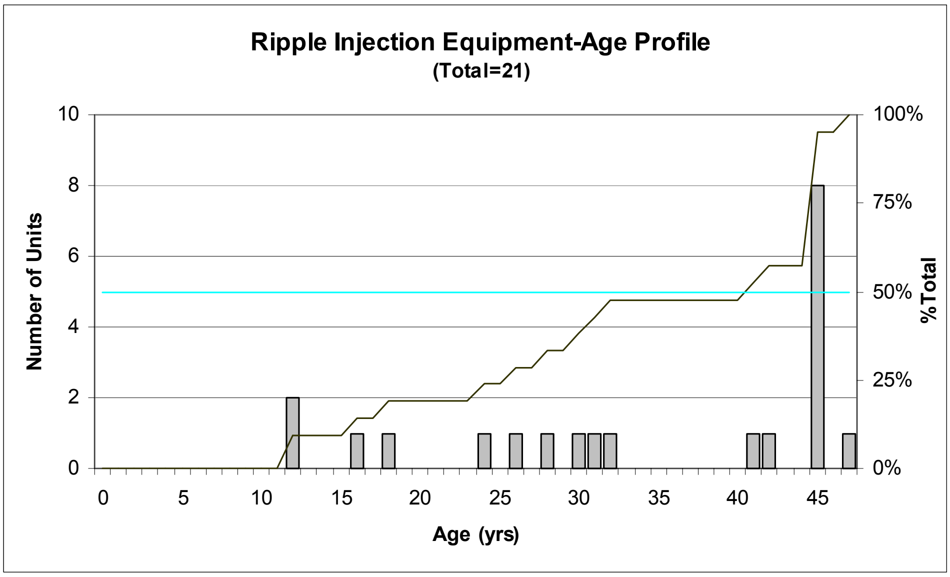


Figure 3.6

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. A general upgrading programme has recently been completed and only routine maintenance is now provided for.

Protection, Local Control and Metering Equipment

With the exception of the newer and refurbished substations in the Central network area the age range of 33kV protection relays is generally between 20 and 45 years. The performance of these electromechanical relays is being monitored closely for any incipient sign of deterioration.

11kV and 6.6kV feeder protection equipment age profile varies up to 50 years old. Problems are now being experienced with these (electromechanical) relays and some replacements will be undertaken.

All recently installed metering is in an acceptable condition but there are many substations where the metering panel and equipment are programmed for replacement.

Buildings, Grounds and Fences

There has been regular maintenance of substation buildings and grounds and security against intrusion is good. Only routine maintenance is planned.

3.1.7 High Voltage Distribution

HV distribution in the main 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 some large HV consumers (e.g. Otago University, Dunedin Hospital and TranzRail Workshops) all feeders are operated as radial feeders with interties 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 distribution 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.

3.1.8 11kV and 6.6kV Lines

Figure 3.8 details the age profile of HV lines. As a result of the system growth in the Dunedin network area in the 1960s and in the Central network area in the 1980s and 1990s the age profile of the high voltage lines is relatively even up to 50 years old. Only 14% of lines are aged more than 50 years and no significant change in maintenance provision is expected over the next ten years.

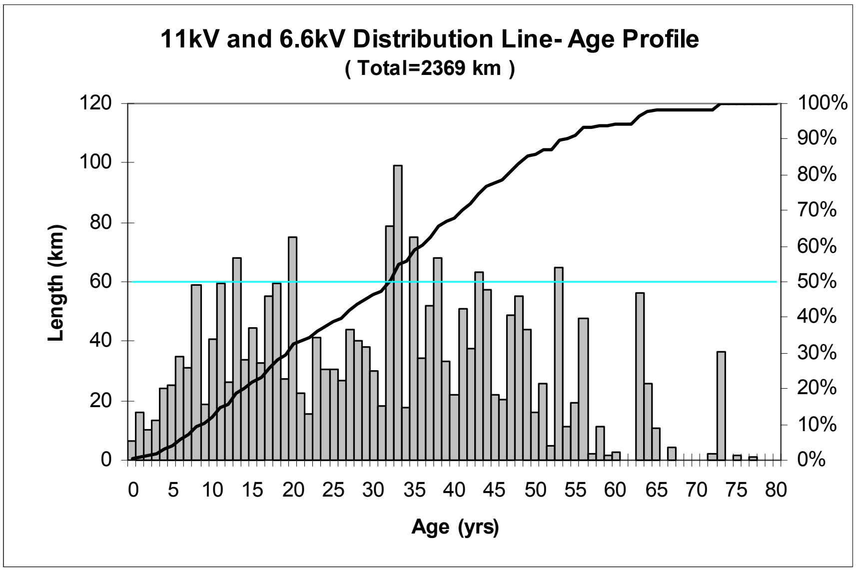


Figure 3.7

3.1.9 11kV and 6.6kV Cables

The age profile of HV cables is shown in Figure 3.9. Ageing of HV cable has not been a particular problem apart from several kilometres of aluminium sheath paper insulated cable which were installed in 1954. 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 included within the planning period.

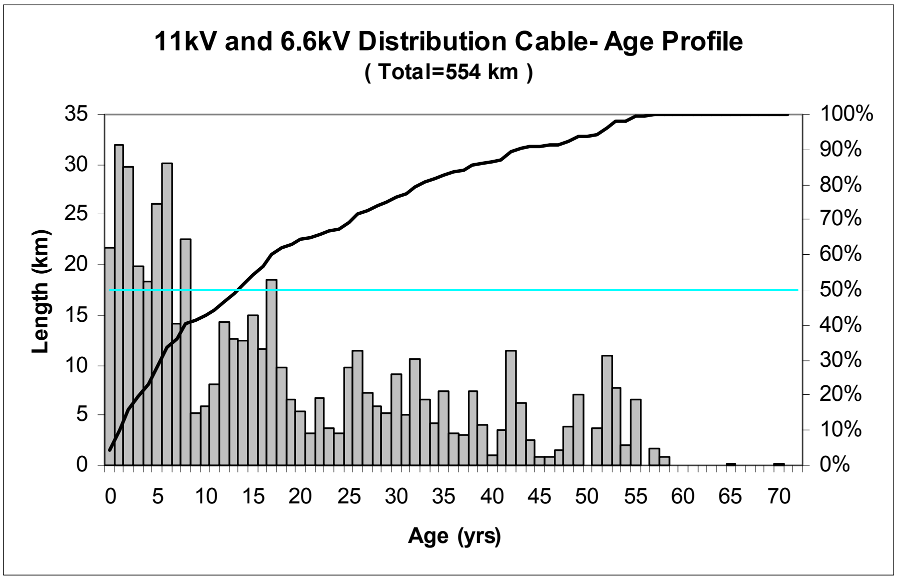


Figure 3.8

3.1.10 Distribution Transformers

Figure 3.10 details the age profile of distribution transformers. With an average life expectancy of 55 years, and with approximately 8% of the transformers with an age over 45 years an increase in expenditure has been planned.

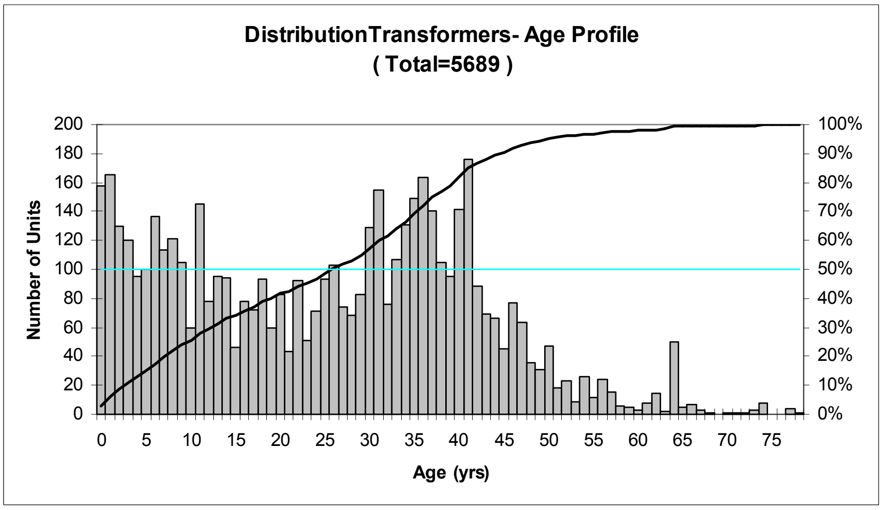


Figure 3.9

3.1.11 Regulators and Autotransformers

Figure 3.11 details the age profile of regulators and autotransformers. With an average life expectancy of approximately 55 years, some units may require replacement within the planning period.

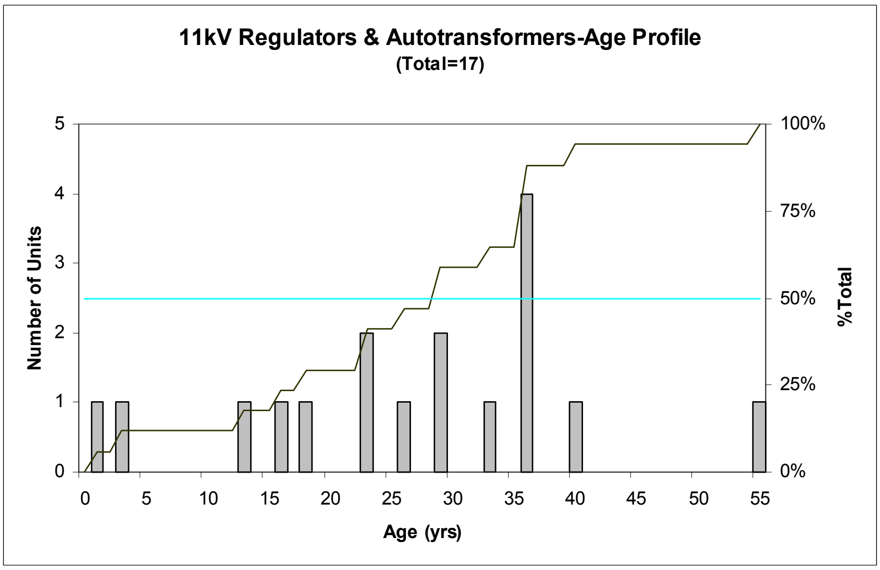


Figure 3.10

3.1.12 Distribution Switchgear

The age profile of distribution switchgear is shown in Figure 3.12. The oldest switches are now approximately 60 years old. The replacement of these switches is detailed in the Six Year Development Plan.

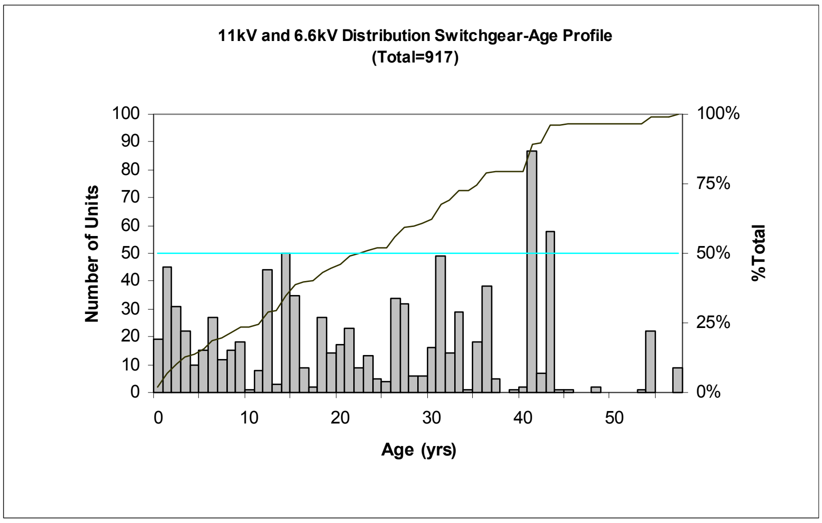


Figure 3.11

3.1.13 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.

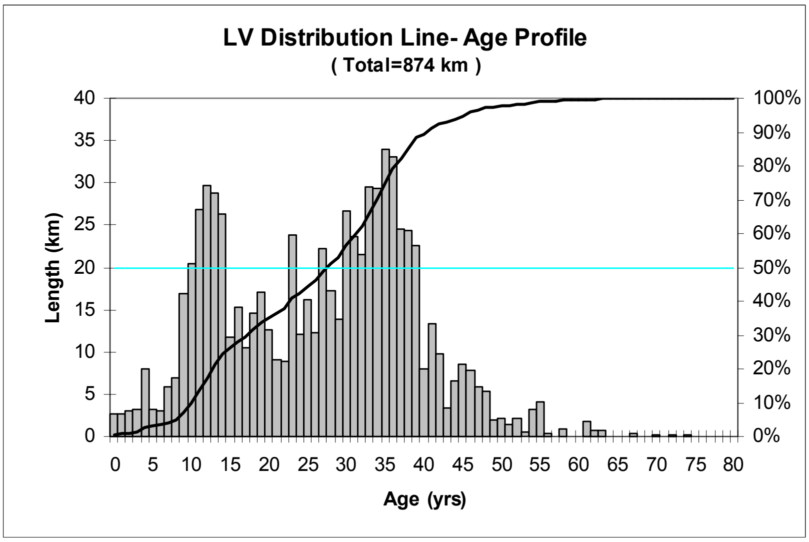


Figure 3.12

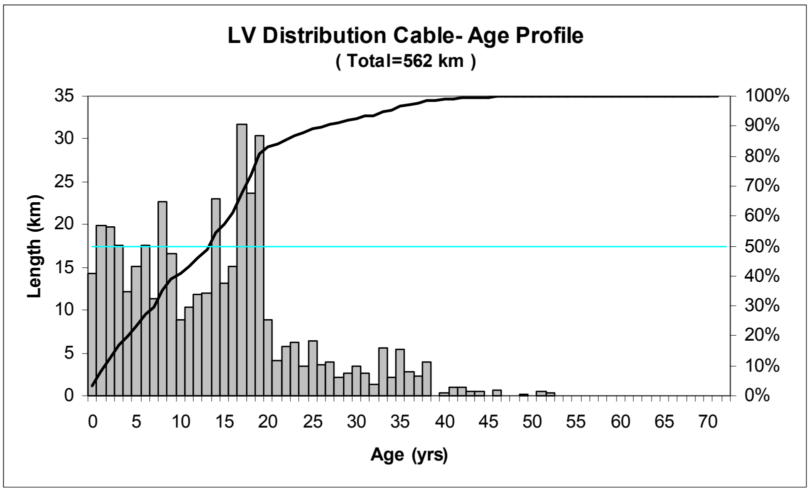


Figure 3.13

3.1.14 Poles

Figure 3.15 details the age profile of poles used for the support of HV and LV circuits. Since 1990, softwood poles have been used increasingly as replacements for both concrete and hardwood poles. However, work on the 66kV project has indicated that softwood poles may not have the assumed life in the Central Otago environment. Further investigation is planned.

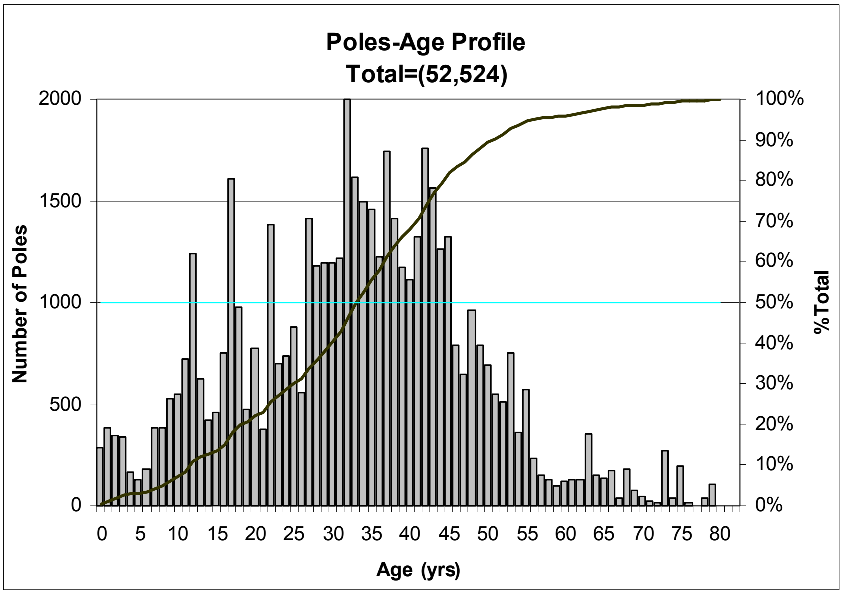


Figure 3.14

3.1.15 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. Pioneer Generation Ltd pays a commercial rate for this service.

The VHF land mobile network is an extensive and exclusive (to Aurora and contractors) system essential for operational, phase identification and maintenance activity. The existing system is old and new equipment is no longer available. However the company has sufficient spares 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 Dunedin area, with the exception of the Taieri zone substations, all communications to zone substations is via copper pilot circuits. For the Taieri area, Telecom data circuits are utilised.

Communication between Dunedin and Cromwell/Queenstown is by Frame Relay access. Between the Central control centre and the Central area zone substations dial-up cellular phone access is utilised.

The Port Chalmers pilot cable has become unreliable and is scheduled for replacement with a radio link in 2004.

3.2 Asset Justification

All assets are justified by present or anticipated requirements except for those detailed in Appendix 1, which have been "optimised" down or out for ODV purposes. Although these assets have been optimised out, many are still required to make the actual network operate (eg, autotransformers) or to meet existing network standards (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 remain in service and are economically justified.

4 Service Levels

4.1 Consumer Oriented Reliability, Security and Availability Performance Targets

Network Performance

Ultimately, Aurora's network performance should be 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. These may include

- 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 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.

Table 4.1: Network Performance History

Period End 31 March	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04
Unplanned						
- Underlying	69.1	41.9	57.7	61.5	55.7	56.6
- Significant Events	15.9	133.8	4.7	0	12.9	23.4
- Transpower	0	13.4	3.3	13.4	12.1	1.0
Total	85.0	189.2	65.7	74.9	80.7	81.0
Planned						
- Underlying	7.9	18.9	16.7	13.8	20.5	16.3
Total						
- Underlying	77.0	60.8	74.4	75.3	76.2	72.9
- Significant Events	15.9	133.8	4.7	0	12.9	23.4
- Transpower	0.0	13.4	3.3	13.4	12.1	1.0
Disclosure Total	92.9	208.1	82.4	88.7	101.2	97.3
-Other LV etc	0.4	0.3	0.5	0.7	0.8	0.1
Overall Total	**93.3**	**208.3**	**82.9**	**89.4**	**101.8**	**97.4**

Expected future performance of the 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 120 minutes without supply per consumer per year.

Table 4.2: Network Performance Target (SAIDI)

	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Unplanned	75	75	75	75	75	75	75	75	75	75
Planned	15	15	15	15	15	15	15	15	75	75
Total	90	90	90	90	90	90	90	90	90	90

Within this strategy analysis is underway 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 and externally negotiated target levels for service covering the following areas:

Restoration of Electricity Delivery - Dunedin Area

Response to a "No Power" Call out

If, as a result of a single LV Connected Customer fuse failure, supply has not been restored to the Connected Customer Installation within 2.0 hours (3.0 hours for the Central network*) of notification of the failure 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 4.0 hours (6.0 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.

*The different standards for the Central network result from the Use-of System Agreement in existence when the network was purchased.

Voltage Complaints

The total number of proven customer voltage complaints per year shall not exceed 10 per 10,000 connections.

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.

Environmental Responsibility Performance

Many of Aurora's assets are in environmentally sensitive areas. Maintenance programmes include the upkeep of noise-reducing enclosures, and 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 three year programme to install oil containment bunds around zone substation transformers was completed in 1997 and distribution transformer storage areas in 1998. A specific instruction covers the handling of sulphur hexafluoride (SF6) gas that is used as an insulate in some equipment. Polychlorinated biphenyls (PCBs) have been eliminated from Aurora's equipment.

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.

4.3 Justification for Target Levels

Performance targets of interest to network users or set by Aurora fall into the following categories:

Table 4.3

	Quality Parameter	Measure	Required by or Set by	Form of Solution
1	Frequency stability			Not influenced by network assets
2	Voltage stability	Voltage range at Consumer Connection	Statute	Demand reduction or capital investment
3	Supply Interruption	Overall measure of interruptions (SAIDI)	Set by users	Maintenance expenditure and/or capital investment
4	Supply Interruption	Duration of individual interruption	Set by users	Operating expenditure and/or capital investment
5	Supply Interruption	Average frequency of interruptions (SAIFI)*	Disclosure Regulations	
6	Supply Interruption	Average duration of interruptions (CAIDI)*	Disclosure Regulations	= SAIDI divided by SAIFI
7	Supply Interruption	Number of Interruptions*	Disclosure Regulations	
8	Supply Interruption	Faults per 100kM*	Disclosure Regulations	
9	Supply Interruption	Frequency of feeder interruptions	Internal	Maintenance expenditure and/or capital investment
10	Customer Service	Customer Service	Shareholder	Operating expenditure

* These targets are required by the Information Disclosure Regulations but are not drivers of either operational expenditure or capital investment. They are outcomes.

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. Aurora sets a target for the maximum number of voltage complaints per ten thousand consumers per annum and, when alerted to voltage excursions, sets a time target for solution. These targets are set against good industry practice.

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* report by the Canterbury University Centre for Advanced Engineering.

In recent times many distribution businesses have adopted the tabular form of security guideline[1]. 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' perception 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, in the view of Aurora, 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 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:

Table 4.4 – Price Versus Quality Survey

Aurora's Price Vs Quality Survey					
Results to 31 March	**2000**	**2001**	**2002**	**2003**	**2004**
Consumers Surveyed	726	4,123	4,220	4,327	4,554
Response Rate	19%	20%	20%	20%	18%
Responses					
Prefer higher quality	9.6%	8.4%	9.3%	9.3%	7.4%
Prefer lower price	90.4%	91.6%	90.7%	90.7%	92.6%

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.

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

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

Uninterruptible 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. For the Aurora network only the area around the main Dunedin hospital has "n-1 security"[2] for faults in sub-transmission, zone substation and high voltage feeder equipment. However, catastrophic events, such as aircraft collision with either the Transpower 220kV double-circuit tower line or the Transpower switch yard, would still result in extensive loss of supply.

Determination of fault probability requires maintenance histories and fault histories of network components to be monitored over decades. Aurora has comprehensive fault statistics for the Dunedin network area, but there is less information regarding the Central Otago assets acquired in 1999 - a problem which time is fixing. 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:

Table 4.5

Type of Interruption	Value of kWh Unserved[3]
Unplanned - Residential	$ 4
Unplanned – Other	$40
Planned – Residential	$ 2
Planned – Other	$20
Planned – Average	$ 4

These values are used in assessing the cost of interruptions that result from asset operating and investment choices. Aurora has made these value assumptions <u>until asset users can agree a better basis</u>. 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 since the above rates have not been increased since they were introduced in 1999, whereas inflation and rising energy prices would otherwise imply an increase.

[2] A single fault event will not cause any loss of supply.
[3] *Reliability of Electricity Supply*, Canterbury University Centre for Advanced Engineering, 1993, page 111.

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

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.

Interruption Targets

Until quality issues have been more widely debated with network users and until the consumer survey results are more valid, 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[4] 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, with the exception of feeder interruption frequency, are outcomes rather than expenditure drivers.

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" (customer-minutes divided by 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 by the setting of internal targets. Specifically, two feeders in the Omakau area and two in Tarras were investigated and additional reclosers installed on them to improve performance.

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 setting targets for these.

[4] For the Central Otago assets the agreement was negotiated with Central Electric Ltd and novated to Aurora Energy, then Dunedin Electricity Ltd.

5 Network Development

5.1 Planning Criteria and Assumptions

Planning Process

After winter loadings each year, a 6-year planning 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 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.

Load Predictions

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

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 less than 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.

Firm Capacity

Firm capacity is the maximum normal load, after any single substation fault, which a zone substation is allowed to carry and is 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 allocating firm load capacity, equipment nominal ratings are increased by a cyclic loading factor. The cyclic loading factors used are given in Table 5.1 below.

Table 5.1: Cyclic Loading Factors

Equipment	Cyclic Loading Factor
Transformers ONAN	1.2
Transformers ONAN/OFAF	Use manufacturers assigned emergency rating
33kV OH Line	1.1
Airbreak Switchgear	1.0
Current Transformers	1.2
Circuit Breakers	1.0
33kV Cables	1.15 (1)

Note (1): Applies to direct buried cables only and assumes one of the paralleled buried cables is not carrying load.

Equipment Standards

All new zone substation transformers will have a nominal ratio of 33,000/11,000 volts or 33,000/6,600 with 17 taps (1.25% steps).

Several zone substation transformers on the Dunedin network have nominal 31kV windings with typical tapping ± 10% and these transformers have limited ability to cope with high 33kV volts. Accordingly, the Dunedin 11kV network is operated at a nominal voltage of 11,550 volts, with 11kV distribution transformers having taps of 11,550 volts + 2.5% to -7.5%. In the Central network area the 11kV is operated with the industry standard 11kV tapping range on distribution transformers, which is 11,000 volts + 2.5% to -7.5%.

The 6.6kV networks are operated at a nominal voltage of 6.6kV with distribution transformers typically having taps of 6,600 volts + 2.5% to -7.5%.

Zone substations will be designed for a maximum short circuit level of 250MVA for 3 seconds. All HV distribution equipment will be able to withstand the maximum fault level at the location where it is installed for 3 seconds.

Ground-mounted distribution switchgear will meet applicable IEC Standards.

Rated voltage	12 kV
Rated current (load break)	400 amps
Rated short circuit current	250 MVA for 3 seconds
Earth switches (rated SC current)	250 MVA for 3 seconds

Pole-mounted air break switches will comply with IEC 129.

Rated voltage	11 kV
Rated current	400 amps
Short circuit rating	25 kA for 1 second

HV cable will be AL PLYS HDPE sheath made to BS6480

Arterial section	300 mm^2
then	185 mm^2
spur	35 mm^2

HV conductor will be

Arterial routes - “Dog” ACSR
Spur routes - “Squirrel” ACSR

HV feeders are provided with 3 phase over-current protection and earth fault protection and are arranged such that the line-end phase-to-phase fault current is at least twice the over-current relay nominal pickup current.

The largest capacity distribution transformer will be 1000kVA, unless there are special circumstances. New pole-mounted substations will only be constructed up to 100kVA capacity.

Economic Analysis

For all development proposal evaluations the net present value (NPV) is calculated. In calculating the NPV the cost of losses (presently valued at $0.075 per kWh and up from previous plans at $0.05 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 Section 4.3.

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 the demand for 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. A programme is currently in place to extend SCADA control into the Central network area, providing centralised control with the Dunedin network through a common SCADA master station.

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

5.5.1 Maintenance Policies

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 and asset type are shown in Figure 5.1.

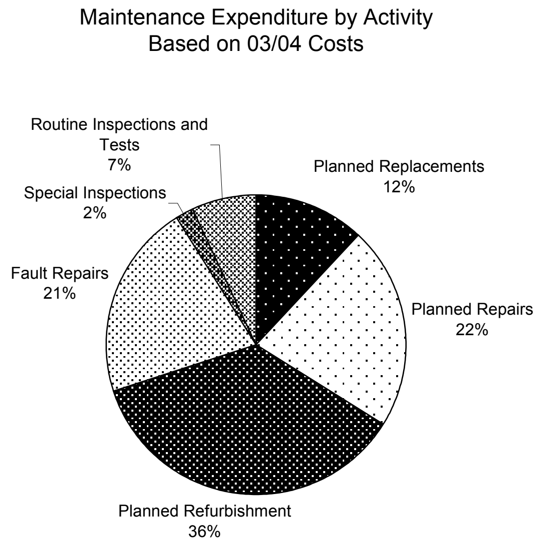
Inspections, Servicing and Testing

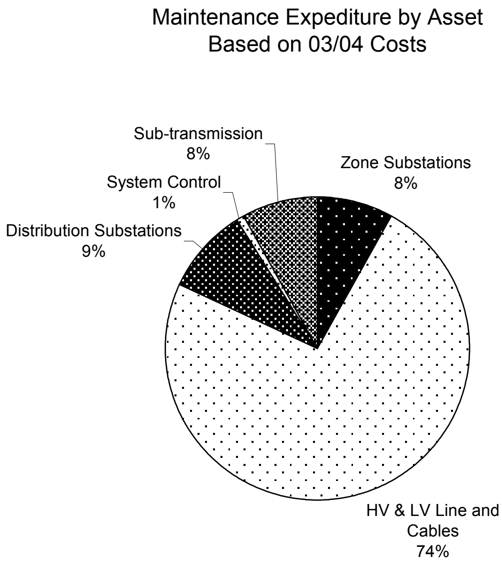
Around 7% of Aurora's maintenance expenditure is for periodic inspections, patrols, servicing and tests. This work is largely undertaken to ensure that defects or emerging risks are identified so that corrective work can be carried out. Servicing can also involve minor component replacements (e.g. seals, bushings etc), but does not involve any significant repairs.

Aurora 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 Aurora'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".





Figures 5.1 & 5.2 Maintenance Expenditure by Activity and Asset

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).

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 service-able 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.

Planned Repairs, Refurbishment and Replacement

Around 70% of maintenance expenditure is for planned repairs, refurbishment and replacement of unserviceable assets. About half of this involves asset refurbish-ment 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.

Maintenance Planning Principles

Plans for asset maintenance are developed from an assessment of asset condition. Aurora continues to define composite maintenance management system 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.

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.

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.

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.

5.5.2 Maintenance Programmes

Sub-transmission Lines and Cables

Projected maintenance expenditure for sub-transmission assets is as follows

Table 5.2: Sub-transmission – Direct Maintenance Expenditure Summary ($000) - By Asset

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
33kV Cables (88 km)	162	164	166	167	170	171	173	175	177	179
33kV Lines (502 km)	130	132	134	136	137	139	140	142	144	146
Pilots	16	16	16	17	17	18	18	19	19	19
Total Expenditure	**308**	**312**	**316**	**320**	**324**	**328**	**331**	**336**	**340**	**344**

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. Apart from some localised failures in the Neville Street cables, there does not appear to be any serious general deterioration in the majority of these cables which should last many years yet. Some minor maintenance is required on the pressure monitoring equipment from time to time.

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 (eg road openings etc). An above-ground inspection programme is in place, which involves inspecting the route of each cable for ground disturbance or ground movement.

Overhead Lines

Annual drive-by patrols are carried out on the overhead 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.

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.

The overhead control and communication pilots to Port Chalmers and Green Island are multicore catenary-supported PVC-insulated cables. These suffer little physical deterioration but can be damaged by pole movement. It is proposed to replace these with a radio links.

Zone Substations

Planned maintenance expenditure for the ten year period is as follows.

Table 5.3: Zone Substations - Direct Maintenance Expenditure Summary ($000) - By Asset

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Power Transformers	185	187	190	192	195	197	200	202	205	208
Civil Works & General	164	166	168	170	173	175	177	180	182	184
Circuit Breakers & Buswork	133	135	137	139	140	142	144	146	148	150
Load Control Equipment	56	57	58	59	59	60	61	62	62	63
SCADA Batteries Alarms	103	104	105	107	108	109	111	112	113	114
Protection & Metering	52	53	53	54	55	56	56	57	58	59
Total Expenditure	693	702	711	721	730	739	749	759	768	778

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 no replacements are considered necessary within the planning period.

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

22 33kV circuit breakers are now over 40 years old and some will require replacement within the next 10 years. These substations include Roxburgh, Alexandra, Berwick, Ward St, Neville St, Outram and Mosgiel.

133 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 Arrowtown, Cromwell, Dalefield, Earnscleugh, Ettrick, Frankton, Green Island, Halfway Bush, Mosgiel, Neville Street, Port Chalmers, Queenstown, Remarkables, Roxburgh, Roxburgh Hydro, Smith St and Ward St.

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 2005 allowing the retirement of the motor generation sets currently (1050Hz). 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.

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.

HV and LV Lines and Cables

Planned expenditure for the next 10 years is as follows.

Table 5.4: HV and LV Lines and Cables – Direct Maintenance Expenditure Summary ($000) - By Asset

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
LV Lines	1,180	1,195	1,211	1,227	1,243	1,259	1,275	1,292	1,309	1326
LV Cables	308	312	316	320	324	328	333	337	341	345
HV Lines	1,077	1,091	1,106	1,120	1,135	1,149	1,164	1,179	1,197	1212
HV Cables	257	260	263	267	270	274	277	281	285	289
Pole Replacements	462	468	474	480	486	493	499	505	512	518
Earths	205	208	211	213	216	219	222	225	228	231
Service Connections	257	260	263	267	270	274	277	281	285	289
Vegetation Control	513	520	527	533	540	547	554	562	569	576
Total Expenditure	4,259	4,314	4,371	4,427	4,484	4,543	4,601	4,662	4,723	4,785

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 will be extended to Wanaka and Alexandra once the work in Queenstown is complete (late 2004).

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. As indicated in Section 3.1, further investigation is underway regarding the serviceability of softwood poles in the harsh environment of Central Otago.

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 5 kilometres of LV conductor and cross-arm replacement is programmed each year. 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. Lately this work has averaged 2 kilometres of upgraded LV conductor per year.

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.

Distribution Substations

Planned expenditure over the next 10 years is as follows.

Table 5.5: Distribution Substations – Direct Maintenance Expenditure Summary ($000) - By Asset

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Transformers	320	325	330	335	340	345	350	355	360	365
Substations Misc Maint	349	353	358	363	367	372	377	382	387	392
Buildings	45	48	50	52	55	57	59	61	63	65
Switchgear	56	54	52	50	48	46	44	42	40	38
Total Expenditure	770	780	790	800	810	820	830	840	850	860

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 41 pedestal mounted transformers are to be replaced. They have been identified a being a latent safety concern. Presently, 6 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.

System Control

Expenditure expected over the next ten years is as follows.

Table 5.6: System Control - Direct Maintenance Expenditure Summary ($000) - By Asset

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
SCADA	11	12	12	12	12	12	12	12	13	14
Communications	41	41	41	41	43	43	44	44	45	45
Ripple Control	10	10	11	11	11	12	12	12	13	13
Total Expenditure	**62**	**63**	**64**	**65**	**66**	**67**	**68**	**69**	**71**	**72**

SCADA

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

UHF and VHF Systems

At 12-monthly intervals, all sites are visited, operational levels are checked, recorded and adjusted if necessary. All aerials, power supplies, security and accessibility are also checked and rectified as necessary. At four-yearly intervals a more detailed inspection of aerials and equipment is undertaken and major operational adjustments made if necessary. Central zone substation remote alarms are checked on a monthly basis from a common point.

Miscellaneous

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

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 5.7.

Table 5.7: Maintenance Expenditure Summary ($000)

Financial Year	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Sub-transmis-sion	487	494	500	507	514	521	528	535	542	549
Zone Substations	1,189	1,204	1,220	1,236	1,252	1,268	1,284	1,301	1318	1335
System Control	107	108	109	110	112	113	114	116	117	118
HV & LV Lines and Cables	7,562	7,660	7,760	7,861	7,963	8,067	8,172	8,278	8385	8444
Distribution Substations	1,332	1,350	1,367	1,385	1,403	1,421	1,440	1,458	1478	1497
Total Expenditure	**10,677**	**10,816**	**10,956**	**1,1099**	**11,244**	**11,390**	**11,538**	**11,688**	**11,840**	**11,994**

5.6 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 total system demand and annual energy input to the system are shown in. Also shown are the estimated forward projections of both values, utilised for system development projections.

Table 5.8 Summary of Zone Substation Capital Projects

Substation	Description	Year	Estimate
Arrowtown	New 33/11kV 3MVA transformer at Morven Ferry Rd and SH6	2006/07	$400,000
Queenstown	Additional transformer -5MVA ex Cromwell	2005	$500,000
Frankton	Replace 33/11kV transformers (ex East Taieri) and replace 11kV switchgear	2007/08	$1.5M
East Taieri	Replace 33/11kV transformers	2007/08	$1.1M
Earnscleugh	New 3MVA zone substation for L & M Mining	2007/08	$350,000
Glenorchy	New 1MVA transformer ex Roxburgh	2004/05	$550,000
Roxburgh	New 3MVA transformer	2004/05	See above
Closeburn	New 1 MVA transformer ex Queensberry	2004/05	$500,000
Tarrras/Lindis	New 3MVA 66/11kV substation	2007/08	$450,000
Berwick	New 3MVA transformer	2005/06	$300,000

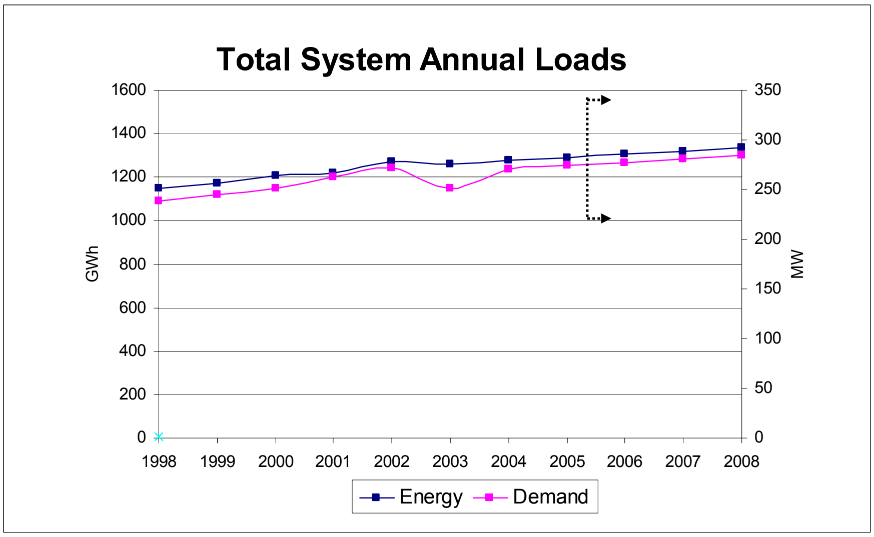


Figure 5.3: Forecast Demand and Energy

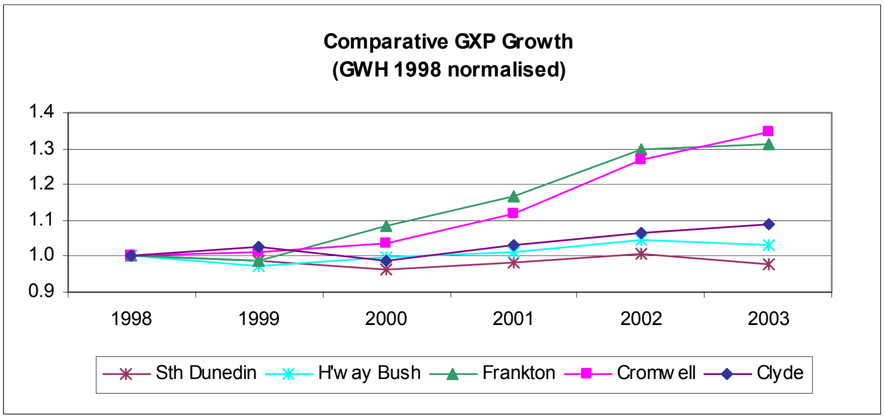


Figure 5.4

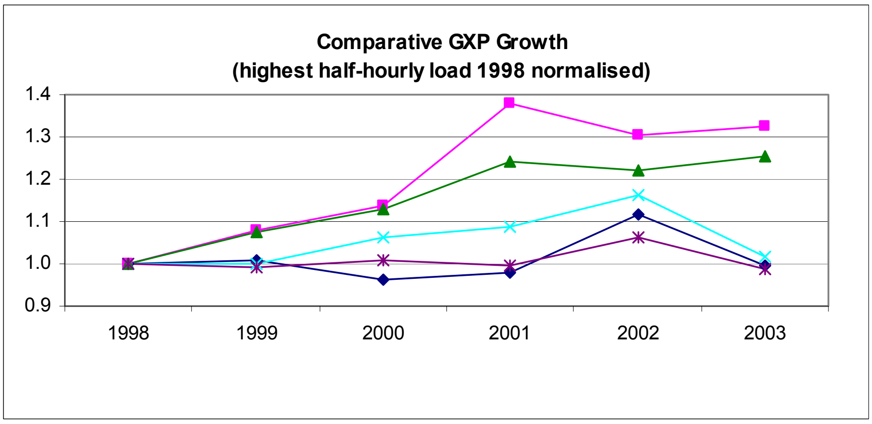


Figure 5.5

The reduction in maximum demand 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 3 to 4 weeks school and University holiday period in June/July. Last winter, aggressive load control was used with retailer agreement, to keep the peak loads down to Transpower-nominated demand levels. The continuation of high rates of subdivision activity has led to the "front loading" of the capital expenditure forecast. The capital expenditure forecast to meet this projected network growth is shown in Table 5.10. Overall, GWh delivered is expected to increase at the rate of 1.6% and demand by 1.2%. See Network Demand Forecast

Table 5.9 Network Demand Forecast

Network Forecasts	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Energy Input (Gwh) (1.6%)	1,279	1,299	1,316	1,333	1,347	1,360	1,374	1,388	1,401	1,416
Maximum Demand (MW) (1.2%)	270	274	277	281	284	288	291	294	298	301
Distribution Transformer Capacity (MVA) (2%)	770	785	801	817	833	849	866	883	901	919

Table 5.10 Capital Expenditure Forecast

	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
New Customers	5,900	5,900	5,900	5,900	4,700	3,980	4,059	4,140	4,200	4260
Local Growth including renewals	2,000	1,900	2,000	2,040	2,081	2,122	2,165	2,208	2,240	2,272
System Development including Scada	210	150	210	214	218	223	227	232	235	239
Closeburn & Glenorchy Zone substations	1050	-	-	-	-	-	-	-	-	-
Berwick Transformer	-	300	-	-	-	-	-	-	-	-
Morven Ferry Substation	-	-	400	-	-	-	-	-	-	-
Cromwell MEN	50	-	-	-	-	-	-	-	-	-
Undergrounding	1,350	1,350	1,350	1,496	1,720	1,720	1,737	1,755	1,772	1,790
Generators	200	-	-	-	-	-	-	-	-	-
Ripple Injection	-	600	-	-	600	-	-	-	-	-
Total	**10,760**	**10,200**	**9,860**	**9,650**	**9,319**	**8,045**	**8,188**	**8,335**	**8,447**	**8,465**

- New Consumers: development required to meet the local area demand dictated by new customer requirements.
- Local Growth: 11kV development ex 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. Should this work be funded by Aurora and not Telecom, this $100K would be expensed.

6 Risk Policies, Assessment, and Mitigation

6.1 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.

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.

Table 6.1: Injection Security

	n-1 Transpower Capacity MVA	Embedded Generation MW	n-1 Generation Capacity MW	Expected Load Demand MW	n-1 Security
Halfway Bush	144	44	0.5	133	Yes
South Dunedin	100	-		64	Yes
Clyde	60	17	13	18	Yes
Frankton	38	2	0.5	40	No
Cromwell	30	4	2	20	Yes

Note: The Frankton demand does not often exceed the “n-1” criteria and discussions are underway with Transpower to determine the optimum time-frame for any proposed upgrade.

Network Capacity (ie Adequacy of Service)

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

Network Reliability (ie 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.

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.

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.

6.2 Details of Emergency Response and Contingency Plans

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.

Firm Capacity

Detailed assessment of plant ratings and the development of the concept of "firm capacity" to discreet portions of the distribution system form the basis for ensuring sufficient network capacity is available under foreseeable plant failure. Guideline documentation details expected peak loads on each HV feeder, available HV feeder interties and their load shifting capability.

Network Reliability

Aurora continues to participate in a "Lifelines" project in which the security of lifelines of Dunedin (representing 73% of consumers) such as the electricity supply system are evaluated in the light of possible civil defence emergencies that could arise from natural disasters.

An essential part of Aurora's contingency planning is the existence of a selection of strategic spare parts, securely located and maintained.

Environmental

The principal environmental risk faced arises from the quantities of insulating oil contained in electrical plant. Oil spill control and containment equipment is located at each zone substation and contractor's vehicles are required to carry smaller capability spill kits for quick response.

7 Performance Measurement, Evaluation and Improvement

7.1 Review of Financial Performance

Table 7.1: Comparison of Actual Operating and Maintenance Expenditure Against Plan

Category	03-04 Plan $000	Actual Expenditure $000	Variance	
Sub-transmission	481	692	239	+50%
Zone Substations	1,173	983	-190	-16%
System Control	106	40	-66	-62%
HV and LV Lines and Cables	7,465	7212	-253	-3%
Distribution Substations	1,315	1262	-53	-3%
Total	10,540	10,189	-351	-3%

Total operating and maintenance expenditure for the 2003/2004 year was within 3% of plan. The major % variation were system control expenditure, which was 62% below budget due to the equipment being extremely reliable, and an overexpenditure of 50% on sub-transmission due to a greater number of cable faults than usual.

Table 7.2: Comparison of Actual Capital Expenditure Against Plan

Category	03-04 Plan $000	Actual Expenditure $000	Variance	
New Connections	4,700	6,900	2200	47%
Local Growth	1,600	2,200	600	38%
System Development	150	150	0	0%
Wanaka Subtransmission (revised budget)	2,357	1,757	-600	-26%
North City SOHI Switchgear replacement	1200	1000	-200	-17%
Coronet Zone Substation	300	300	0	0%
Undergrounding	1,701	1,351	350	-21%
Total	12,008	13,658	1650	14%

Customer-driven expenditure (New Connections) was 47% above budget due to higher than expected activity in the Central Network. The demand also impacted on Load Growth, where the investment to maintain capacity again rising demand is less able to be ascribed to known load increases.

The Wanaka Upgrade project completion will give a significant improvement to the security of supply to the Upper Clutha region.

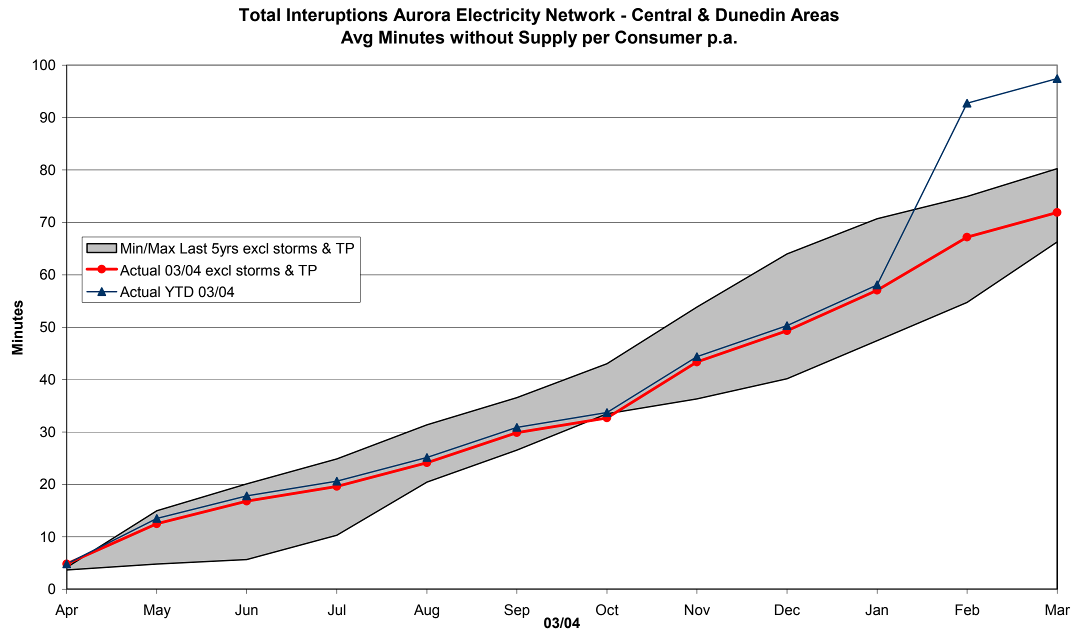
7.2 Review of Physical Performance

The System Average Interruption Duration Index provides an overall measure of asset performance for the year.

Table 7.3: Comparison of Plan to Actual
(Average Minutes Without Supply Per Connection)

	03-04 Plan	Actual
Unplanned		
- Underlying	64	57
- Significant Events	10	(1) 23
- Transpower	1	1
	75	81
Planned		
- Underlying	15	16
Total		
- Underlying	79	73
- Significant Events	10	23
- Transpower	1	1
	90	97

Notes:
(1) = no of significant events in the year - significant events are defined as all those which are over 300,000 customer-minutes.



For unplanned interruptions, the “underlying: pattern was also 10 minutes better than budget. However, significant events exceeded budget by 16 minutes, resulting in the total being 9% above budget.

For the planned interruptions, the level of new 11 kV construction produced 33% more customer interruption minutes than budgeted for, despite more extensive use of live line working techniques. This reflects the growth that is being experienced in Central Otago. Nevertheless, improvements in other classes of planned interruptions resulted in only a minor increase over budget for all planned interruption.

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.

Voltage Complaints

Voltage complaints are registered and investigated. The target is less than 10 complaints per 10,000 customers. Aurora has 72,100 customers.

Table 7.4

Target	Proven Complaints 03-04
<72.1	18

7.3 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 1 minute of SAIDI are subjected to a full engineering investigation and a quarterly summary to the Aurora Board. These reports specifically identify areas in which system performance could be improved by way of improvements to material selection, items of plant, design, configuration and operation. Targeting such performance improvements has produced proposals for SCADA extension and distribution automation in areas of below average performance.

APPENDIX 1

SCHEDULE OF OPTIMISED ASSETS

The total reduction in ODRC value due to optimisation is $6.3 million. A breakdown of the optimisation carried out is given below:

Sub-Transmission

- Cable lengths for Ward Street and Neville Street were reduced in distance to the closest grid exit point.
- South City Circuit 2 was deleted.
- Revised ages of lines were attributed to the Waipori A, B & C lines.

Zone Substation

- Unused and lightly loaded HV feeder breakers.
- Berwick voltage regulator.
- Ripple injection optimised from 18 HV injection units to three 33 kV injection units.
- 33 kV switchyards at 6 zone substations optimised to transformer feeder configuration. Protection at these substations also optimised to transformer feeder configuration.
- Unused 33kV switchgear at Fernhill deleted.
- 2000 Amp incoming circuit breakers and cables reduced to 1200 Amp to reflect modern design would be 11kV.
- Transformers at substations that will not reach their n-1 rating in the next 10 years reduced in size.
- Buildings at South City, Neville Street were optimised to smaller buildings.

System Control

- Excess parallel pilot circuits were deleted.
- Open pair telephone circuits Mosgiel to Berwick were deleted.

HV Distribution

- In the Dunedin region, some 6.6kV HV cable and lines were optimised to a smaller size to reflect that a modern network would operate at 11kV.
- 6.6/11kV Auto Transformers were optimised out as a modern network would operate at 11kV only.

Distribution Switchgear

- Oil circuit breakers at distribution substations were optimised to oil switches or fuse switches.

Voltage Regulators

- One very old spare voltage regulator was deleted.