



AURORA ENERGY LTD

Asset Management Plan Number 15

April 2008 – March 2018

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



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F O R E W O R D

This is the fifteenth network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd and covers the 10 year period from 1 April 2008.

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

D I S C L A I M E R

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

1 Summary

1.1 Purpose

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

1.2 Background and Objectives

This Asset Management Plan describes the asset management objectives, strategies, policies, plans and systems adopted by Aurora for its electricity distribution networks. It has been prepared in this format to meet the Electricity Information Disclosure Requirements 2004 and subsequent amendments. A reconciliation matrix is shown at the end of the document (Appendix C).

1.3 Assets Covered

The network assets consist of two geographically separate networks. The larger network is the electricity network which supplies 52,823 consumers in and adjacent to the urban area of Dunedin. The network in Central Otago, which stretches from Raes Junction to Lakes Wakatipu and Wanaka and north to St Bathans and Makarora, supplies 26,915 consumers.

The network assets comprise the types and quantities summarised in Table 1.1, located generally as shown in Figure 3.1. Their general condition is detailed in Section 3. The asset value and age data originates from the 2007 ODV data.

Asset Category	Quantity	RC	% by \$
Subtransmission	591 km	\$41,560,245	10%
Zone substations	36	\$75,148,800	17%
HV cables	735 km	\$69,555,611	16%
HV lines	2359 km	\$61,974,472	14%
Distribution transformers	6,220	\$51,364,500	12%
Distribution switchgear	7,080	\$30,322,126	7%
Distribution substations	6,063	\$11,308,000	3%
LV distribution	1,726 km	\$72,989,380	17%
Service connections	92,923	\$12,686,685	3%
Street lighting distribution	210 km	\$5,332,330	1%
System control		\$1,667,200	< 1%
Sundry		\$562,593	< 1%
Total		\$434,471,942	100%

Table 1.1 – Types and Quantities of Assets (from March 2007 ODV)

Approximately 3.2% (by Depreciated Replacement Cost, DRC) of existing assets have been “optimised” out of Aurora’s revenue base. This represents the degree of asset stranding due to changes in either consumer requirements or technology since these assets were installed.

1.4 Service Levels

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

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

Table 1.2 – Service Level Objectives

Aurora’s primary service level focus is SAIDI; other indicators are considered to be secondary. Despite the market survey response detailed in section 4.2.2, that consumers do not want to pay more for improved reliability or pay less for slightly worse reliability, Aurora believes that making small improvements to SAIDI minutes is appropriate with specific emphasis on reducing the number of interruptions (SAIFI). This should satisfy some concerns about the number of interruptions.

1.5 Network Development Plans

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

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

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Total	19,620	18,210	18,160	19,040	19,470	19,930	20,400	20,740	20,280	20,330

Table 1.3 - Capital Expenditure

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

1.6 Lifecycle Asset Management Planning

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

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

As a result of continual refurbishment work, the network is in reasonably good condition. Improved knowledge and analysis of maintenance trends continues to result in inspection and test intervals being extended in some instances and reduced in others. Maintenance requirements are continuously monitored and are subject to change as optimum levels evolve. The maintenance expenditure from Table 6.1 and Table 6.2 are summarised below in Table 1.4.

Financial Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Inspection (Table 6.1)	1,395	1,434	1,473	1,514	1,555	1,599	1,643	1,687	1,734	1,782
Maintenance and Refurbishment (Table 6.2)	12,564	12,910	13,264	13,629	14,004	14,388	14,784	15,192	15,610	16,038
Total Maintenance Expenditure	13,959	14,344	14,737	15,143	15,559	15,987	16,427	16,879	17,344	17,820

Table 1.4 – Total Maintenance Expenditure (\$000)

1.7 Risk Management

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

- (1) health and safety;
- (2) responsibilities dictated by the Resource Management Act;
- (3) security of major items of plant;
- (4) maintenance and/or restoration of supply.

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

1.8 Evaluation of Performance

The diagram below compares the performance achieved by Aurora's network with that achieved by other line businesses in the year to 31 March 2007.

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

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

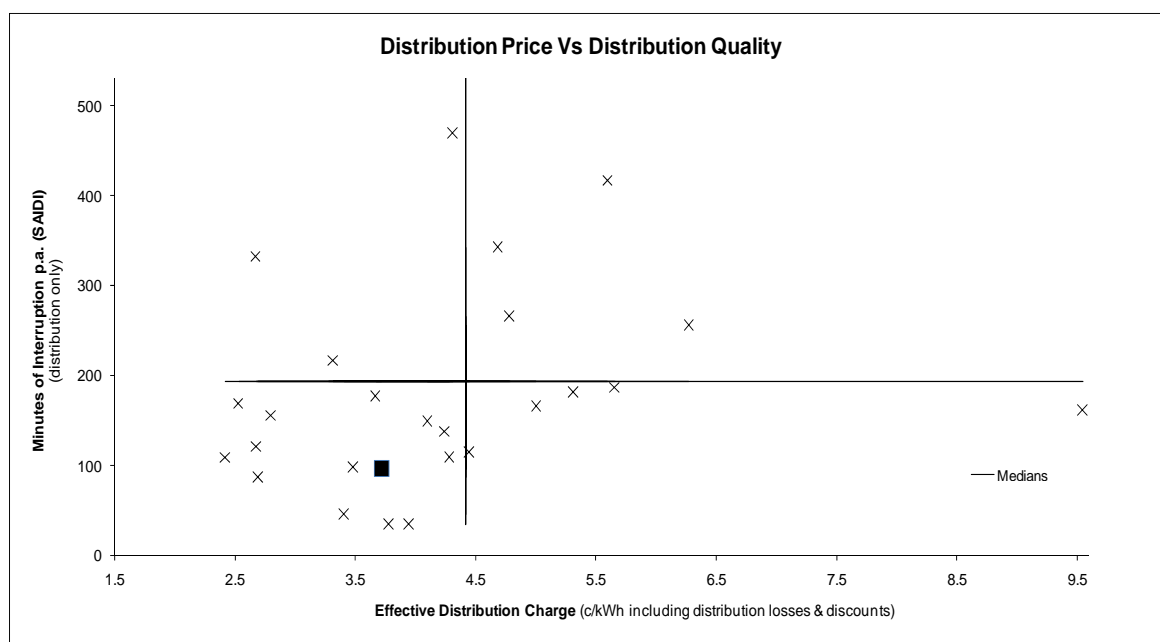


Figure 1.1 – Price-Quality Matrix

1.9 Stakeholder Consultation

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

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

Aurora Energy Ltd
P O Box 1404
DUNEDIN

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

¹ SAIDI = system average interruption duration index minutes

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

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

2 Background and Objectives

2.1 Purpose

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

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

Preparation of the Asset Management Plan in this format also assists in meeting the requirements of Section 24 and Schedule 2 of the Electricity Information Disclosure Requirements 2004.

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

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

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

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

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

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

This Asset Management Plan covers the period from 1 April 2008 to 31 March 2018 and represents an evolution of the production of annual Asset Management Plans published for the Dunedin network since 1993. Due to the changes in the date for disclosing AMPs from five months in arrears to immediately before the year starting 1 April, this edition of the AMP is not expected to be subject to regulatory scrutiny.

The Board approved this (2008 – 2018) Asset Management Plan on 30 July 2008.

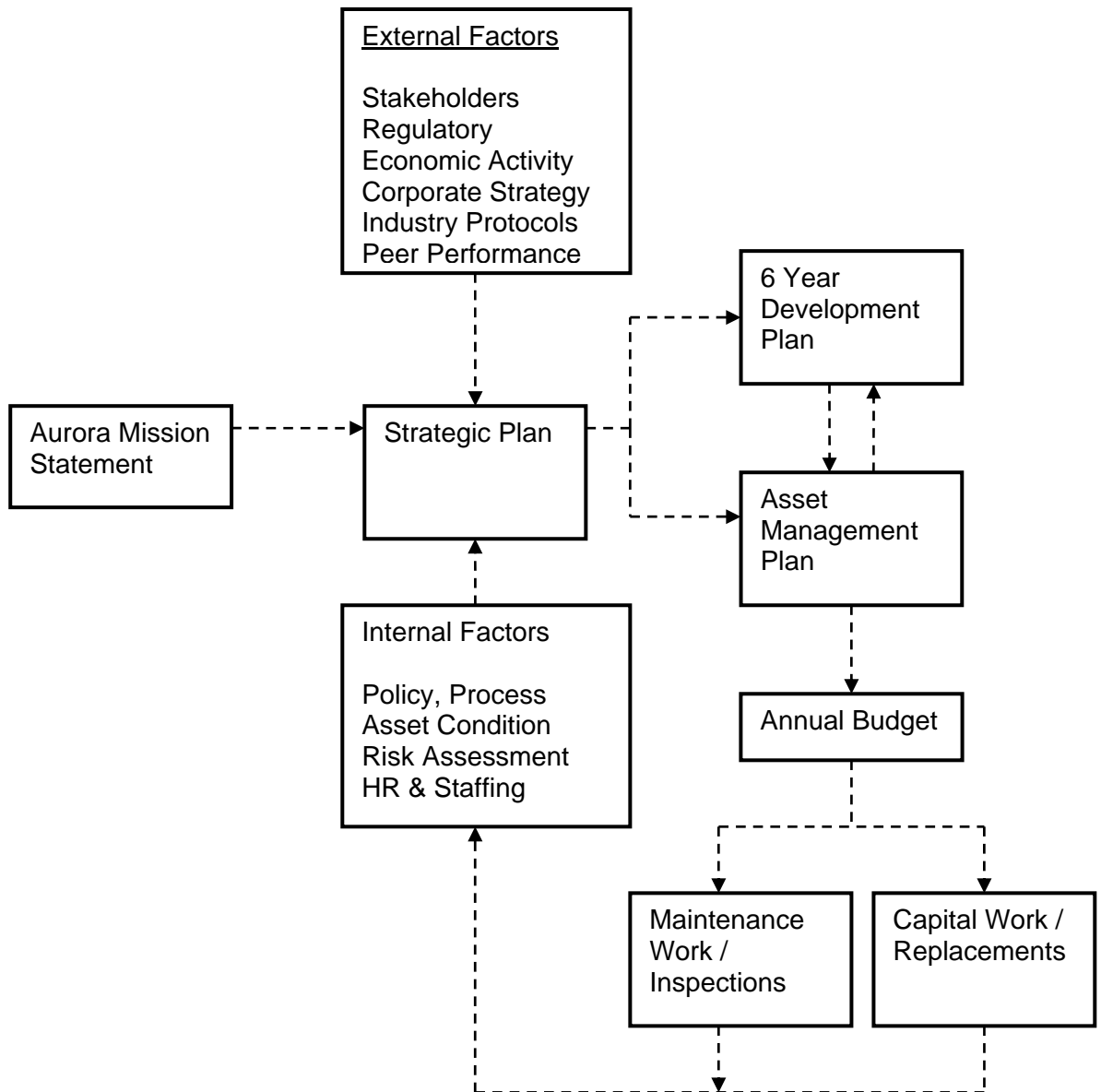


Figure 2.1 - Interaction between other business processes and plans

2.3 Period to Which Plan Relates

This plan relates to the 2008 - 2018 period.

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

There is an obvious degree of uncertainty in any predictions of the future and, accordingly, the AMP is uncertain. The presence of several modest electrical loads driven by turbulent commodity markets, public policy trends and possible generation opportunities within Aurora's demand profile, means the future is perhaps less certain than many other infrastructure businesses that have greater scale. Accordingly, Aurora has attached the following certainties to the timeframes of the AMP.

Timeframe	Residential and Commercial	Large Commercial and Industrial	Intending Generators
Year 1	Very certain	Reasonably certain	Reasonable certainty
Years 2 and 3	Certain	Some certainty	Some certainty
Years 4 to 6	Reasonably certain	Little if any certainty	Little if any certainty
Years 7 to 10	Reasonably certain	Little if any certainty	Little if any certainty

2.4 Stakeholder Interests

2.4.1 Stakeholders

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

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

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

Table 2.1 – Stakeholder Interests

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

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

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

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

2.4.2 Continuance of Supply

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

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

2.5 Accountabilities and Responsibilities

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

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

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

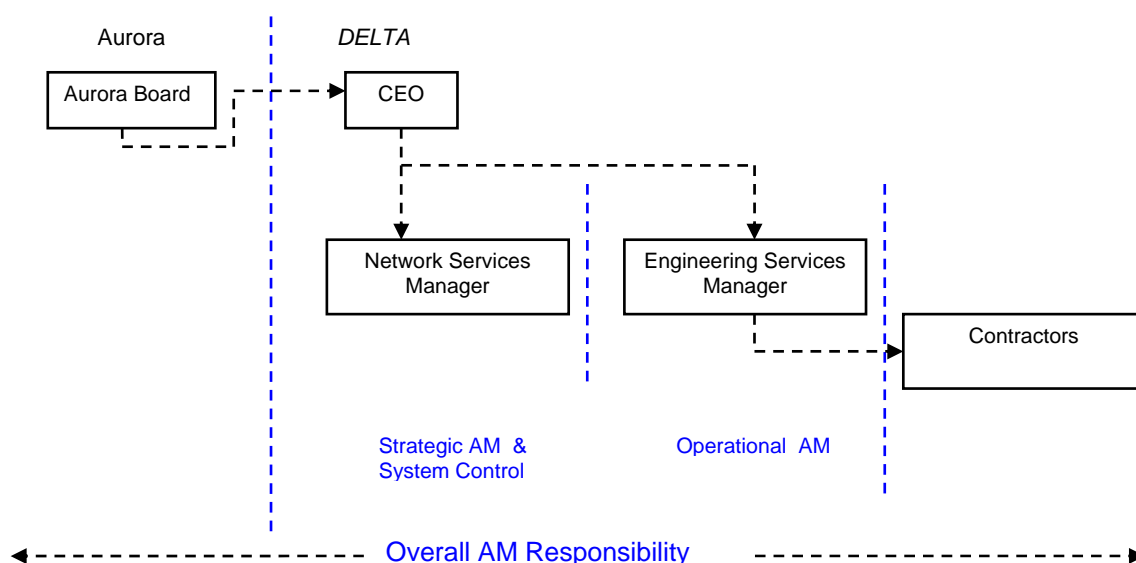


Figure 2.2 - Asset Management Accountabilities and Responsibilities

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

The delegated financial levels are given in Table 2.2 below:

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

Table 2.2 – Delegated Financial Authority Levels

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

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

DELTA has made use of external contractors and consultants for works associated with the annual operational, maintenance, capital replacement and network development programmes. On average 20% of maintenance works and 25% of capital works are completed by contractors other than *DELTA*.

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

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

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

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

2.6 Details of Asset Management Systems and Processes

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

- Application-for-supply Management System: the process of negotiating and constructing new connections is electronically managed from application to livening.
- Maintenance Management System: storage and analysis of maintenance histories for specific plant items and for asset classes allows optimisation of maintenance and replacement at both class and item levels.
- Work Order Management System: the issue of work to and inspection of work by contractors is managed electronically within the SAP accounting software.
- Production of ODV summaries and analysis is integrated with the core records of plant items.
- Outage Management System: planning and notification of outages and production of interruption statistics.

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

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

Section 4 details deficiencies in asset information (mainly dates) for each of the asset categories described. These deficiencies are being incrementally addressed as this becomes the economic course of action.

3 Assets Covered

3.1 High Level Description

3.1.1 Areas Covered

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

- The geographically smaller network is the electricity network which supplies 52,823 consumers in the urban areas of Dunedin and Mosgiel and the inner reaches of the Taieri Plains. The Dunedin area is supplied from two GXP's between which Aurora has significant interconnection at 6.6 kV and 11 kV.
- The network in Central Otago, which stretches from Raes Junction in the south to Lakes Wakatipu and Wanaka in the north-west and St Bathans and Makarora in the north-east, supplies 26,915 consumers. The Central region is characterised by its separate river valley areas mandating a radial network supplied from three transmission grid exit points (GXPs). Aurora has no high voltage interconnections between the Central GXPs.

A small embedded network was installed in Te Anau in 2005 which is connected to The Power Company network.

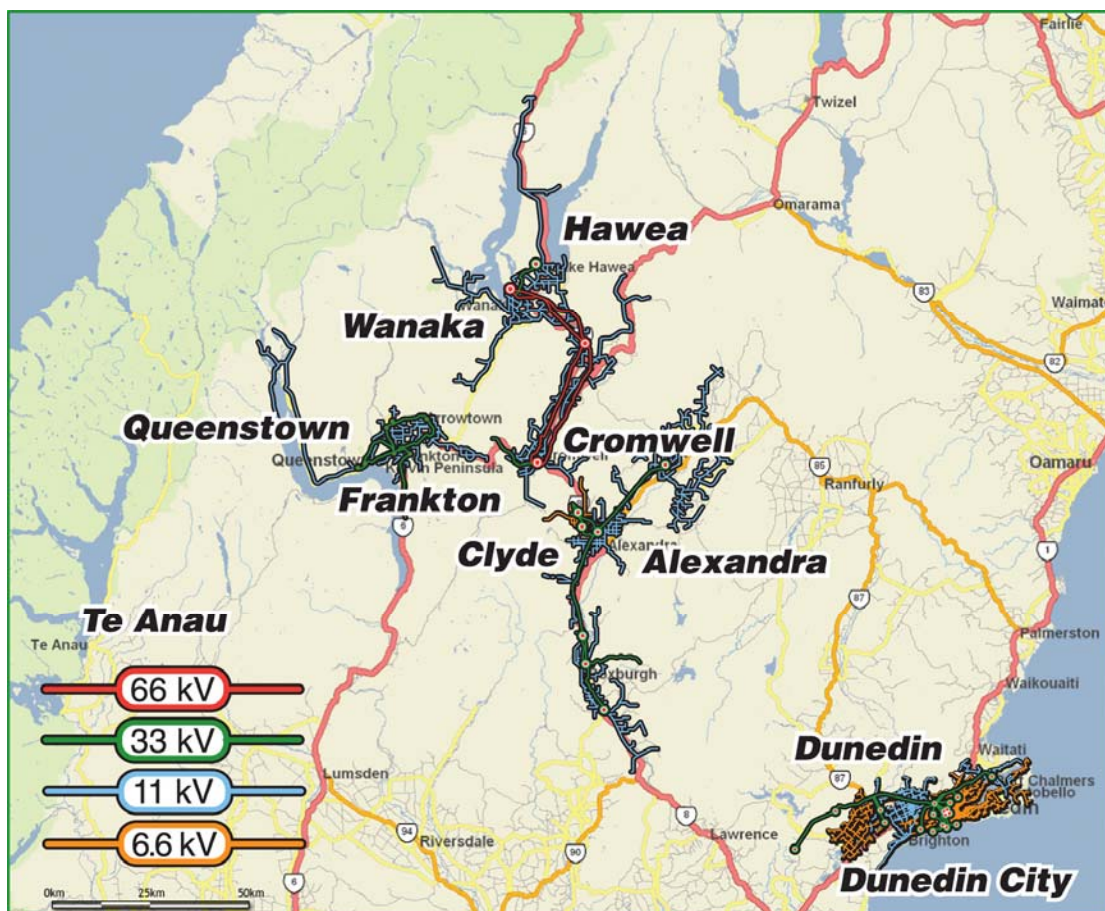


Figure 3.1 – Aurora Network

3.1.2 Large Consumers

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

3.1.3 Load Characteristics

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

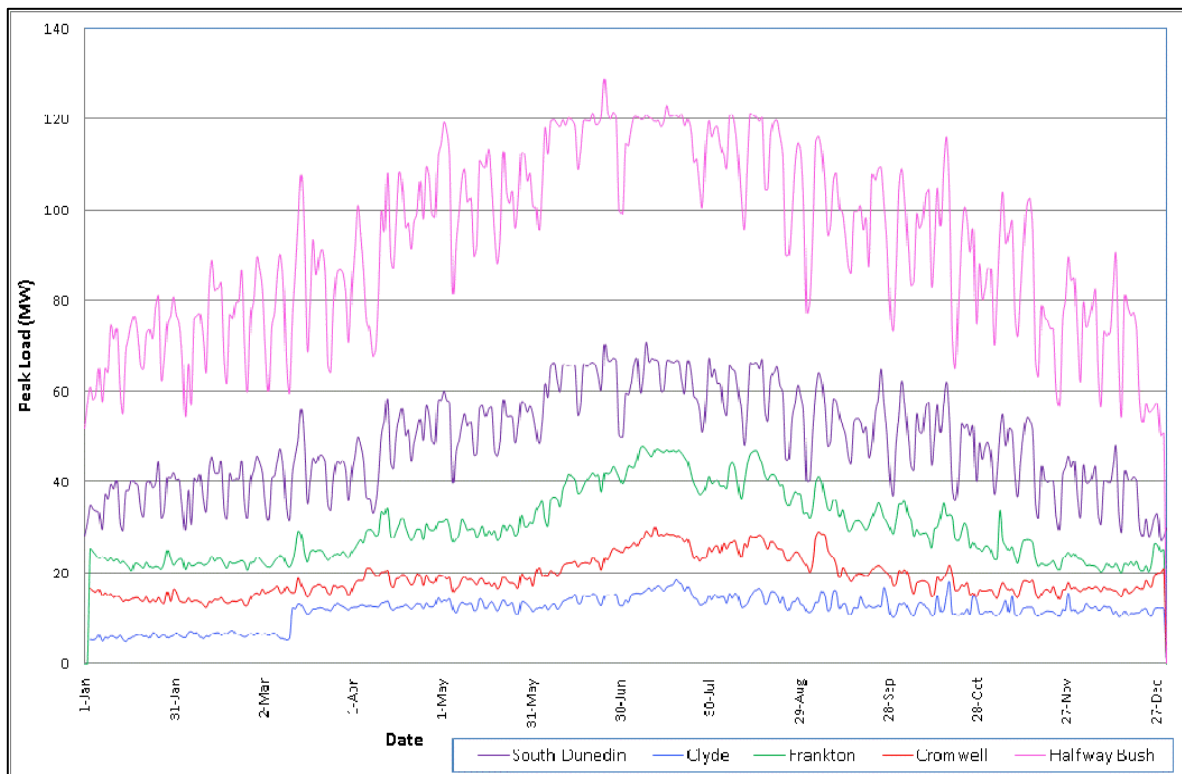


Figure 3.2 - Graph of Grid Exit Point Daily Load Peaks (2007)

The Frankton and Cromwell GXP peak loads usually occur during the July school holidays, due to the influx of skiers into the area which drives three components of demand – ski field load, normally vacant holiday houses are occupied, and hotels, motels and café's experience higher occupancy. There has been significant growth in summer irrigation load on the Cromwell GXP where the Queensberry zone substation has a summer peak; however, the Cromwell GXP peak is not expected to shift away from the winter within the planning period.

The Clyde GXP serves Alexandra, Roxburgh and surrounding areas and load also peaks in winter. In some areas supplied from Clyde, frost-fighting pumps put a large demand on the system for a short time during September and October.

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

3.1.4 2007 Load Data

The key load and embedded generation statistics for the 2007 calendar year are presented in Table 3.1.

GXP	Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin	Total
2007 peak MW including embedded generation	18.0	30.6	49.7	130.6	71.0	299.9
2007 energy transported GWh	83.3	125.4	210.3	608.0	324.8	1351.8
Total number of ICPs	6,500	9,500	10,900	36,280	16,600	79,830
Off take n-1 capacity (24 hour winter post contingency) MVA	27	35	88	112	81	

Table 3.1 - GXP Load and Capacity Summary (2007 Calendar Year)

3.2 Network Configuration

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

GXP	Embedded Generation	Connection Voltage kV	Installed Generation Capacity MVA
Halfway Bush	Waipori Ravensdown Fertiliser	33 6.6	44 2.8
South Dunedin	None		
Frankton	Glenorchy Wye Creek	11 33	0.5 1.3
Cromwell	Roaring Meg	33	4.3
Clyde	Fraser Teviot	33 33	2.5 14.8
Total			71.2

Table 3.2 - Schedule of Embedded Generation

3.3 Subtransmission (66kV and 33kV)

3.3.1 Dunedin Area

The Dunedin network area is supplied from the Halfway Bush and South Dunedin GXPs. There are 19 33kV breakers at Halfway Bush and 11 at South Dunedin (one spare). The main Dunedin urban area is supplied by transformer-feeder zone substations, with each substation having two 33/6.6kV transformers. The North East Valley zone substation is teed off the Port Chalmers zone substation 33kV circuits. The Taieri Plain area, including Mosgiel, is served by four zone substations which are supplied from the three parallel 33kV lines between the Halfway Bush GXP and TrustPower's Waipori power scheme. An overview of the network is shown in Figure 3.3 and zone substation details are in Table 3.3.

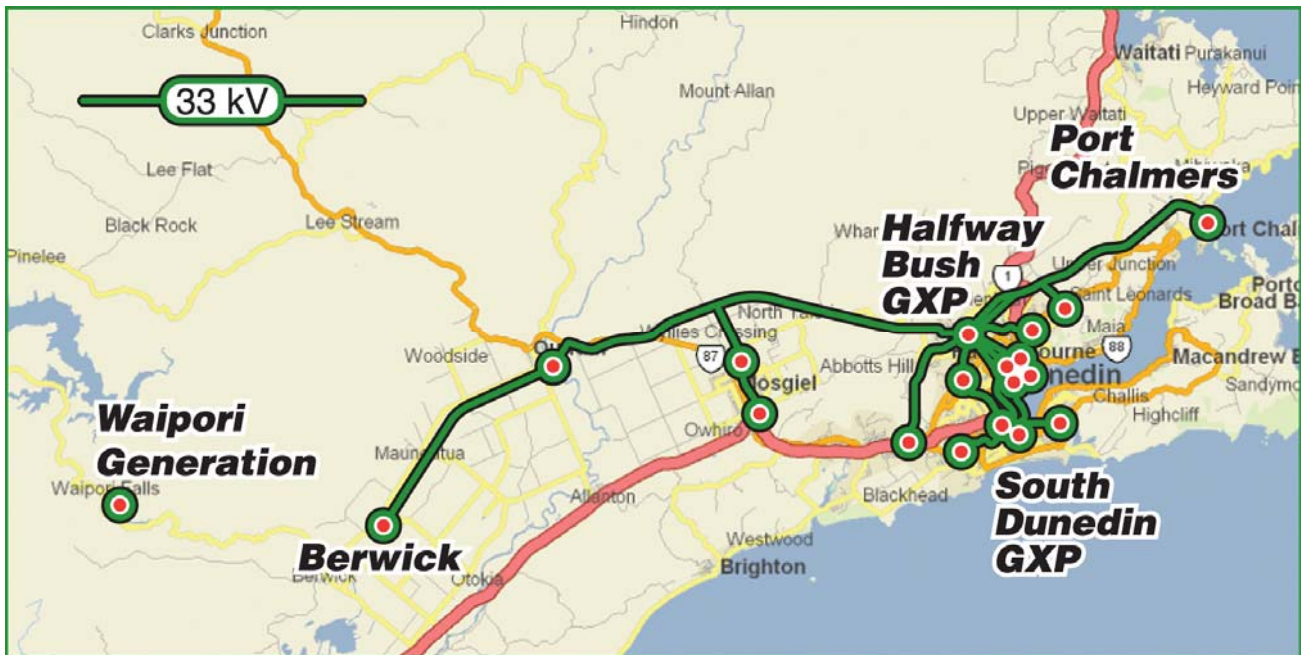


Figure 3.3 - Dunedin Subtransmission Network

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

Table 3.3 - Zone Substations in the Dunedin Area

3.3.2 Frankton Area

The Frankton area is supplied via seven 33kV circuit breakers from the Frankton GXP. Two circuits supply the Wakatipu Basin via a ring and there are three parallel lines from Frankton to Queenstown and two circuits supply the Frankton zone substation. A tee off the ring supplies the Remarkables ski field and the Wye Creek generating station. An overview of the network is shown in Figure 3.4 and zone substation details are in Table 3.4.

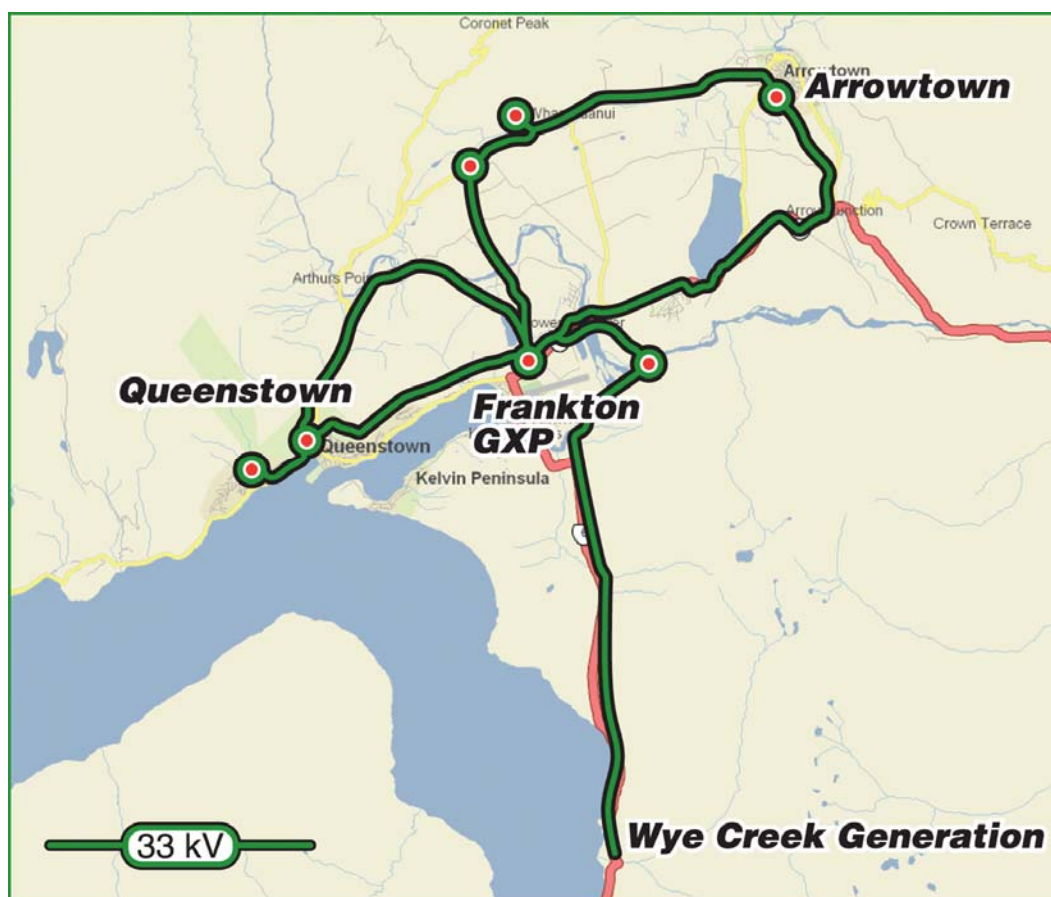


Figure 3.4 - Frankton Subtransmission Network

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

Table 3.4 - Zone Substations in the Frankton Area

3.3.3 Cromwell Area

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

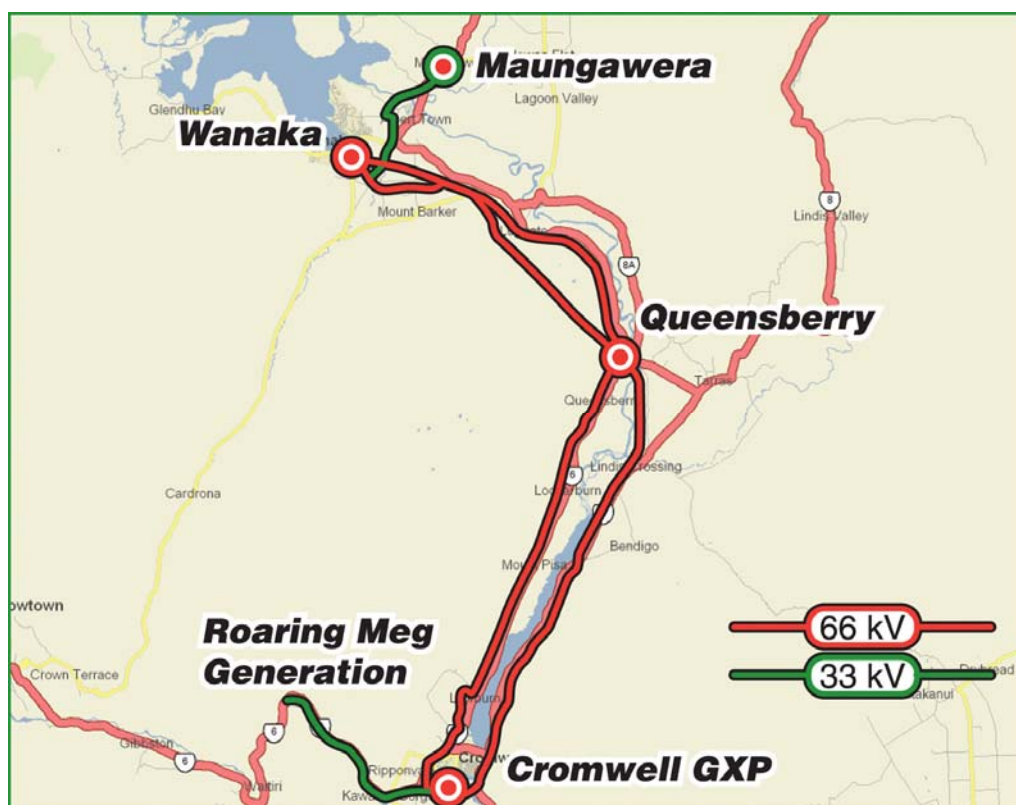


Figure 3.5 - Cromwell Subtransmission Network

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

Table 3.5 - Zone Substations in the Cromwell Area

3.3.4 Clyde Area

The Clyde area is supplied via two 33kV circuit breakers at the Clyde GXP. These circuits supply Alexandra via a parallel pair of overhead lines. A significant amount of the Clyde area load is supplied from the Teviot, Horseshoe Bend and Fraser generation stations. There are two parallel 33kV lines between Alexandra and Roxburgh that deliver generation output to Alexandra from the south. Omakau to the north-east and Ettrick to the south are each supplied by a single 33 kV line. An overview of the network is shown in Figure 3.6 and zone substation details are in Table 3.6.

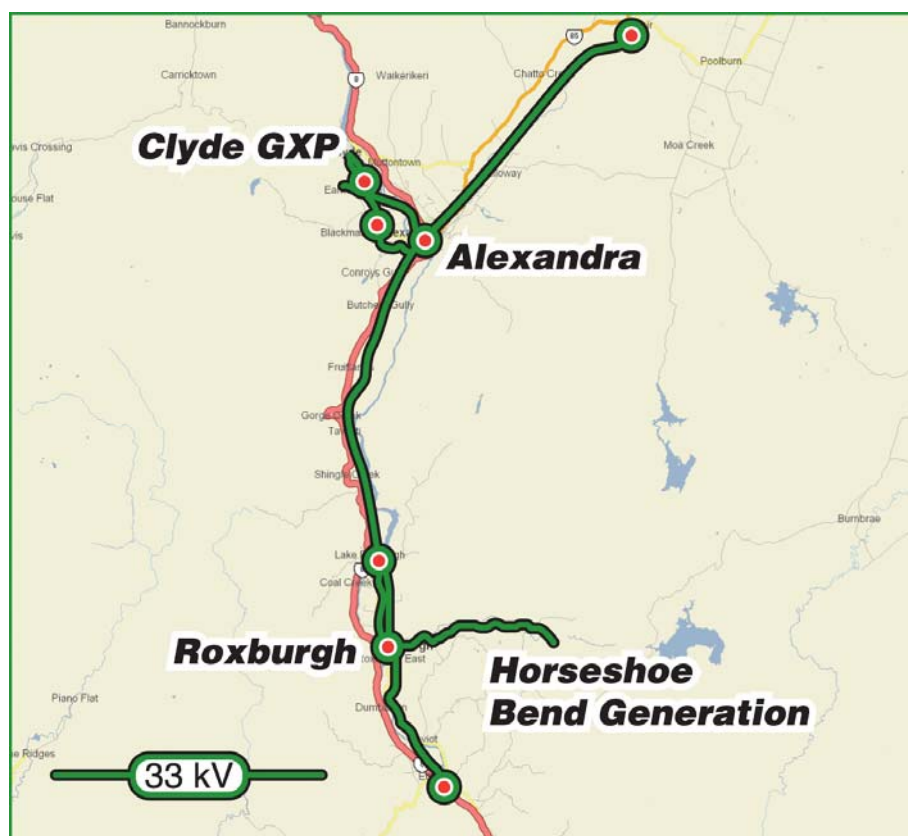


Figure 3.6 - Clyde Area Subtransmission

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

Table 3.6 - Zone Substations in the Clyde Area

3.4 HV Distribution (11kV and 6.6kV)

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

3.4.1 Dunedin Area

HV distribution in the Dunedin area is via 182 HV feeders. Four zone substations, Berwick, Mosgiel, East Taieri and Outram have 11kV feeders and the remaining fourteen have 6.6kV feeders. The HV distribution voltage by location is shown in Figure 3.7 and the quantities by voltage are shown in Table 3.7. All feeders are radial with a high degree of meshing in the metro areas, except for the supplies to Otago University and the Hillside Workshops which have dedicated paralleled feeders. HV cable insulation in the Dunedin area is predominately PILC (87%) with the remainder being either XLPE (6%) or unknown (7%). For many years, all new cable has been rated for 11kV operation even when it operates at 6.6kV.

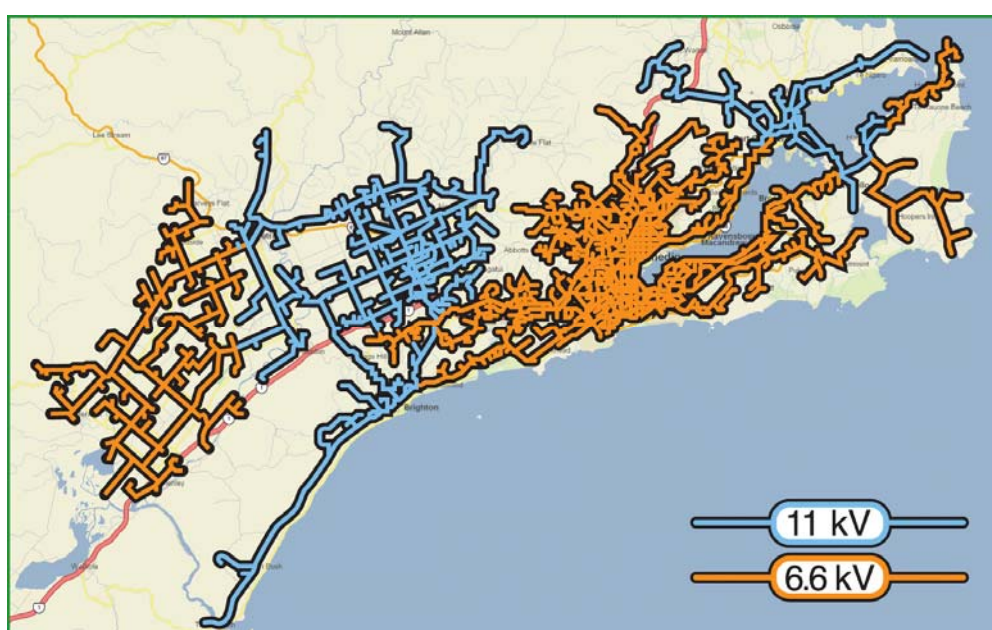


Figure 3.7 - Dunedin HV Distribution by Voltage

Voltage	km	% Overhead	% Underground
11kV	332	83%	17%
6.6kV	703	67%	33%
Total	1,035	72%	28%

Table 3.7 - Dunedin HV Distribution Quantities (as at 31/3/2007)

3.4.2 Central Area

HV distribution in the Central area is via 59 feeders. All HV feeders are 11kV except for those in the Clyde area which are 6.6kV. All feeders are radial with limited interties to other feeders. The HV distribution voltage by location is shown in Figure 3.8 and the quantities by voltage are shown in Table 3.8. HV cable insulation in the Central area is a mix of PILC (28%), XLPE (65%) and unknown (7%). In Central, there is a significant quantity of rural HV cable due to local authority requirements and the high number of rural lifestyle subdivisions.

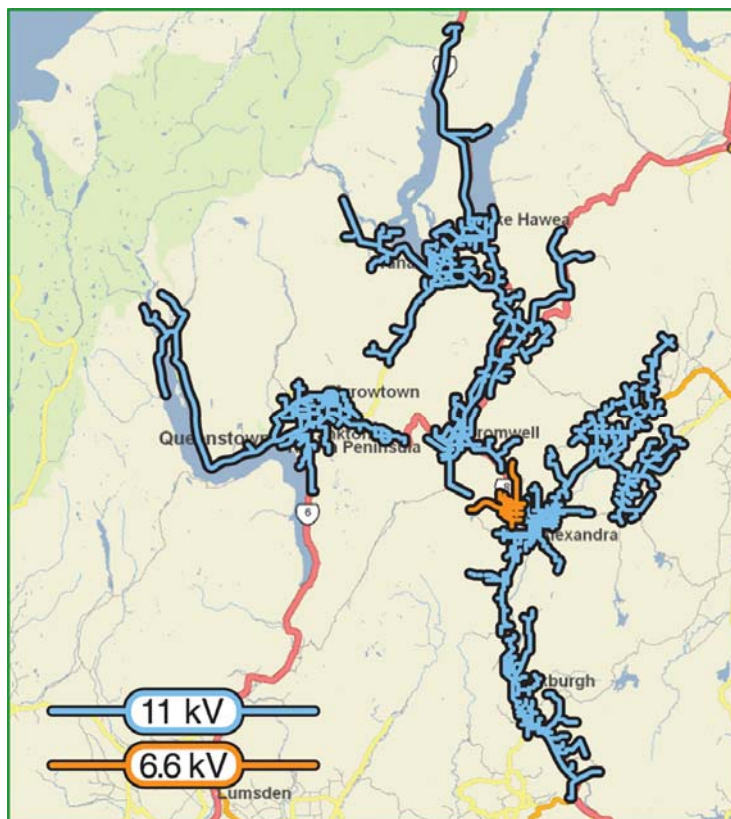


Figure 3.8 - Central HV Distribution by Voltage

Voltage	km	% Overhead	% Underground
11kV	1,980	78%	22%
6.6kV	77	88%	12%
Total	2,057	78%	22%

Table 3.8 - Central HV Distribution Quantities (as at 31/3/2007)

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

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

Substation Type	Count
Pole Mounted	4,184
Pedestal Mounted	16
Ground Mounted	1,843
Underground	20
Total	6,063

Table 3.9 - Substation Count

3.5.1 Pole Mounted

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

3.5.2 Pedestal Mounted

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

3.5.3 Ground Mounted

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

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

3.6 LV Distribution (0.4kV)

LV distribution is via radial feeders. In central business districts, LV intertie capability is provided by link boxes. In urban residential areas, there is limited LV intertie capability. The quantities by area are given in Table 3.10.

Area	km	% Overhead	% Underground
Dunedin	999	81%	19%
Central	721	34%	66%
Te Anau	5.6	0%	100%
Total	1,726	61%	39%

Table 3.10 - LV Distribution Quantities (as at 31 March 2007)

The reason that the Central area has a greater proportion of underground LV compared to Dunedin is due to the growth experienced in Central since it became mandatory to underground in new subdivisions

3.7 Secondary Assets

3.7.1 SCADA

Aurora has two SCADA systems; a system dating from 1998 in Dunedin, for the control of the Dunedin area, and a Lester Abbey system dating from 2000 for the control of the Central network. All zone substations, except the 1MVA Remarkables substation, have an RTU.

3.7.2 Telecommunication Systems

In the Dunedin area, a pilot cable network installed with 33kV cables provides communication with twelve of the eighteen zone substations and Telecom facilities are used for the six zone substations not covered by the pilot network. In the Central area, communication is via a combination of the Aurora owned VHF system in the Upper Clutha area and the Team Talk radio system elsewhere.

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

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

3.7.3 Load Management Systems

Dunedin Load Management

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

Central Load Management

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants, one at each GXP. There are approximately 24,500 Decabit relays on the network that are mainly owned by Electricity Retailers. The Central injection plants are controlled by a custom made system dating from 1996.

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

3.7.4 Metering Systems

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

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

3.7.5 Mobile Substations/Generation

Aurora owns three mobile substations 11kV/6.6kV/400V, two 500kVA units and one 300kVA unit. Two units are based in Dunedin and one in Cromwell. Aurora does not own any mobile generators but continues to monitor the economics of doing so.

3.7.6 Power Factor Correction Equipment

Power factor equipment is not installed on the network. However some consumers have installed power factor correction equipment in order to comply with Aurora policy to maintain a power factor of at least 0.95.

3.8 Asset Details by Category

The value of Aurora's assets by category as derived from the 2007 ODV valuation of the network is presented in Table 3.11, and each category is detailed below.

Asset Category	Quantity	RC	% by \$
Subtransmission	591 km	\$41,560,245	10%
Zone substations	36	\$75,148,800	17%
HV cables	735 km	\$69,555,611	16%
HV lines	2,359 km	\$61,974,472	14%
Distribution transformers	6,220	\$51,364,500	12%
Distribution switchgear	7,080	\$30,322,126	7%
Distribution substations	6,063	\$11,308,000	3%
LV distribution	1,726 km	\$72,989,380	17%
Service connections	92,923 (See Note 1)	\$12,686,685	3%
Street lighting distribution	210 km	\$5,332,330	1%
System control		\$1,667,200	<1%
Sundry		\$562,593	<1%
Total		\$434,471,942	100%

Notes

1 Now includes street light connection points

Table 3.11 - ODV Value of the Aurora Network (from March 2007 ODV)

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

3.8.1 Subtransmission Lines

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

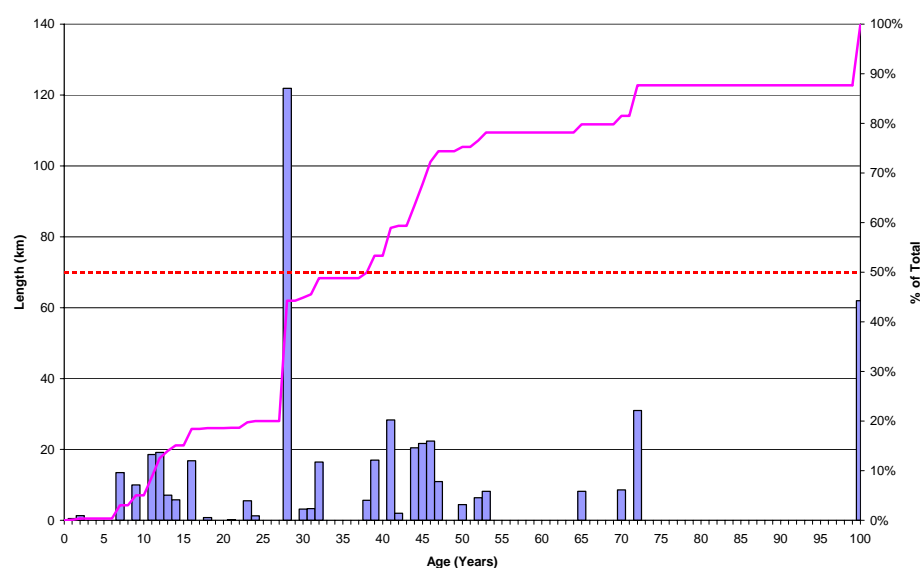


Figure 3.9 – 66 & 33kV Lines Age Profile (Total = 504)

The lines shown at 100 years are the Taieri “A” and “B” lines to Waipori. These lines have had all of their original poles replaced but the original conductor is still performing well

All lines are in good condition and no significant expenditure is expected within the planning period based on existing loadings. The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses and its maintenance history. A line located on the coastal areas near Dunedin may have a life of about 30 years, limited by salt corrosion; however, the same line located in Central will often be in excellent condition after 70 years. Generally, in coastal areas insulators will last about 30 years, conductors 40 years and poles over 45 years.

3.8.2 Subtransmission Cables

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

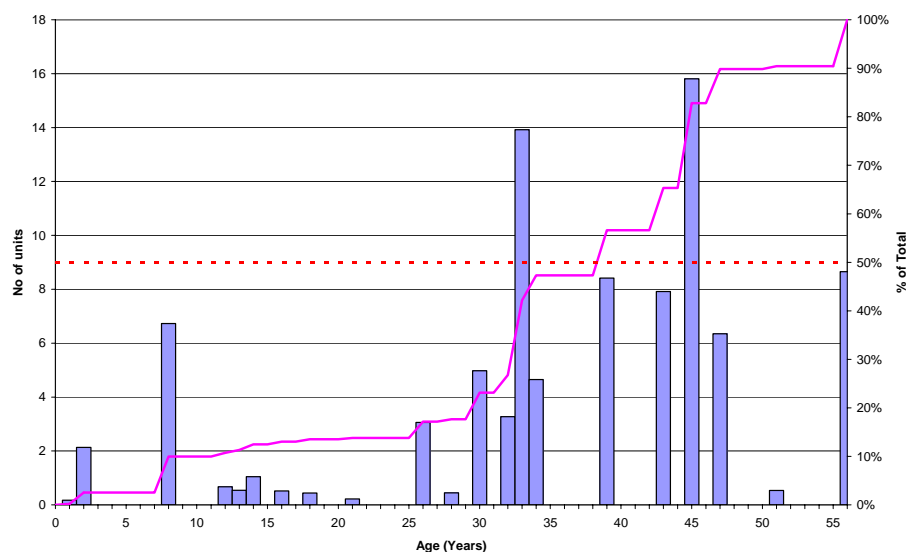


Figure 3.10 – 33kV Cables Age Profile (Total 90 km)

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

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

3.8.3 Zone Substation Power Transformers

The age profile of zone substation transformers is shown in Figure 3.11. Transformers that are subject to moderate loading, minimal through faults, prudent monitoring and maintenance practices should last for at least 60 years. All power transformers have performed well to date and monitoring has not detected any latent concerns with the exception of one transformer at Halfway Bush which had water ingress in November 2006 and another where Dissolved Gas Analysis (DGA) indicates that planned maintenance is necessary. The two 76 year old units at Berwick are scheduled to be replaced with a single 3MVA transformer early in 2008. Subject to economic evaluation, the Ward Street transformers are scheduled for replacement later in the planning period in association with a major upgrade of the substation.

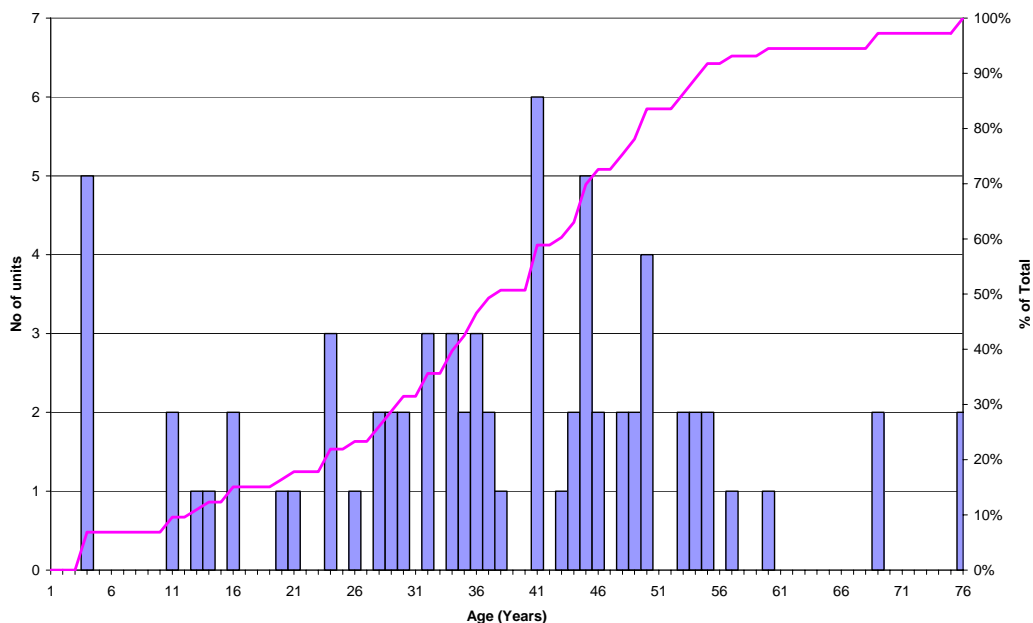


Figure 3.11 – 66 and 33kV Zone Substation Transformers Age Profile (Total = 73)

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

3.8.4 Zone Substation 66kV and 33kV Circuit Breakers

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

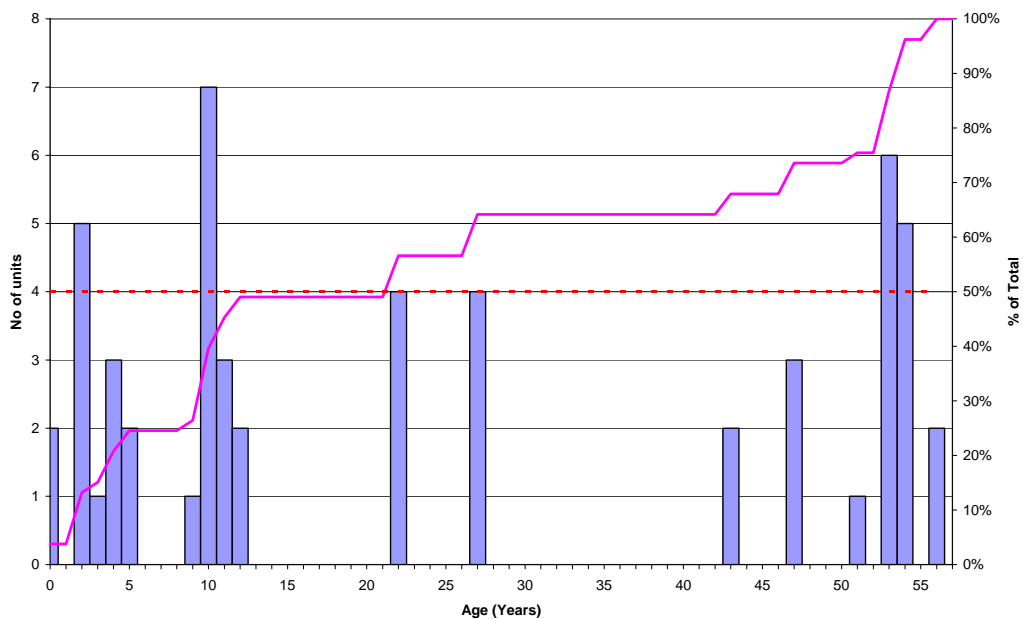


Figure 3.12 – 66 and 33kV Zone Circuit Breakers Age Profile (Total = 53)

3.8.5 Zone Substation 11kV and 6.6kV Circuit Breakers

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

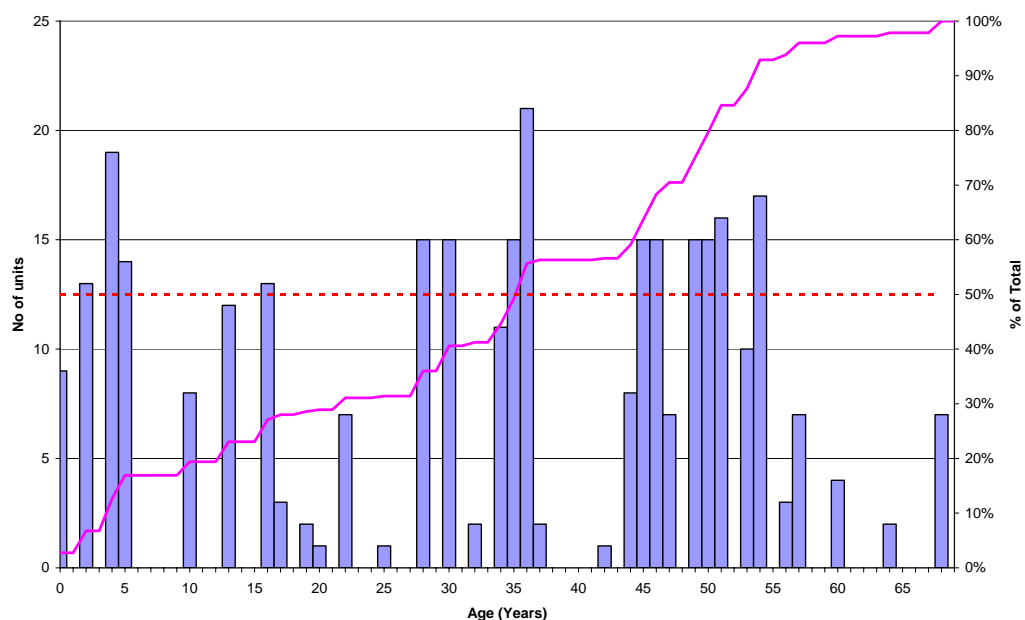


Figure 3.13 – 11 and 6.6kV Circuit Breakers Age Profile (total = 325)

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

Substation	Manufacture Year	Status	Number CBs	Year
Ward Street	1938	Planned	14	2010/11
Roxburgh	1950	Planned	1	2009/10
Frankton	1950	Planned	8	2009/11
Remarkables	1950	Monitor	1	
Neville St	1953	Monitor	14	
Mosgiel	1954	Planned	10	2008/09
Halfway Bush	1956	Monitor	16	
Green Island	1957	Monitor	15	
Smith Street	1958	Monitor	15	
Earnsclough	1960	Monitor	1	
Dalefield	1960	Monitor	1	
Outram	1963	Monitor	8	

Table 3.12 – Scheduled Zone Substation Circuit Breaker Replacements

3.8.6 Load Control Equipment

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

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

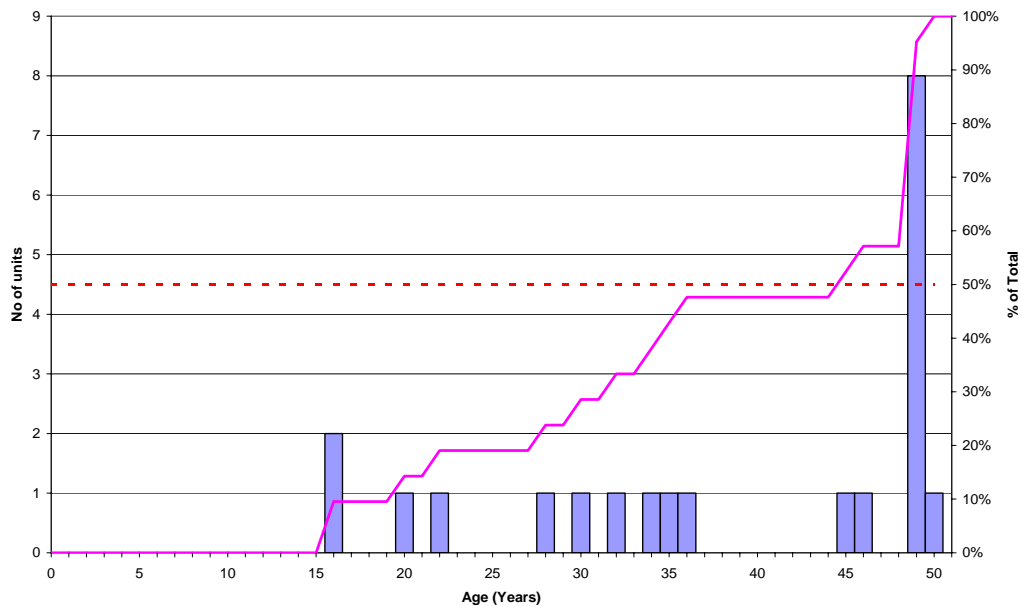


Figure 3.14 – Load Control Equipment Age Profile (Total = 21)

3.8.7 Zone Substation Protection Relays

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

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

3.8.8 SCADA Remote Terminal Units

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

3.8.9 Other Zone Substation Equipment

Battery banks at substations include flooded and sealed lead acid cells with various life expectancies. Replacement and new banks will consist of sealed recombination lead acid cells which have low maintenance requirements, lower initial cost and a 10 year rated life.

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

3.8.10 Buildings, Grounds and Fences

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

3.8.11 HV Lines

Figure 3.15 details the age profile of HV lines by conductor age. Aurora has 2,359 km of HV lines and the age of 57 km (2%) has yet to be confirmed. As a result of growth in the Dunedin network area in the 1960s, and in the Central network area in the 1980s and 1990s, the age profile is relatively even up to 50 years old. 21% of conductor is aged more than 50 years and no significant change in maintenance expenditure is expected over the planning period as their underlying reliability is good.

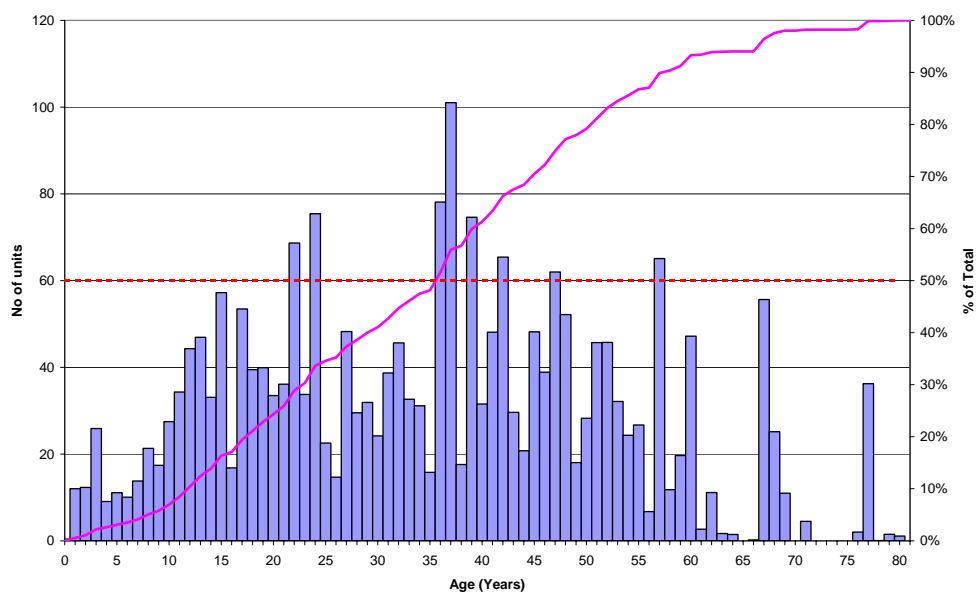


Figure 3.15 – 11kV & 6.6kV Lines Age Profile (total = 2,359 km)

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3.16. Aurora has 734 km of HV cable of which the age of 27 km (3.7%) has yet to be confirmed. Deterioration of HV cable has not been a particular problem apart from several kilometres of aluminium sheath paper insulated cable installed in 1954, where sections of this cable have been replaced as and when the need or opportunity arose. Most repairs are due to either faults at joints or terminations, or due to third party damage.

No major replacements are necessary within the planning period.

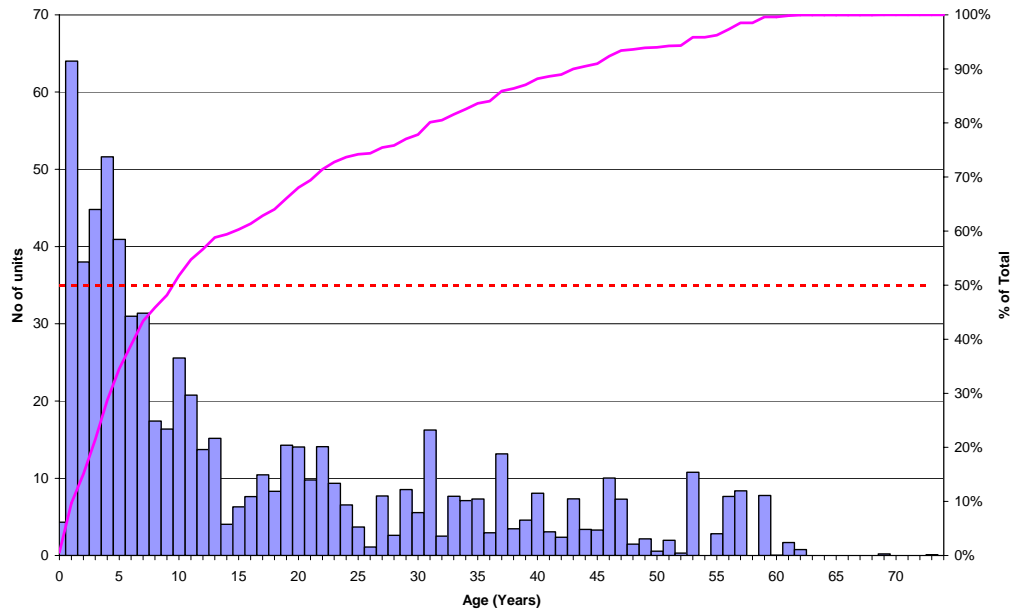


Figure 3.16 – 11 & 6.6kV Cables Age Profile (Total = 734 km)

3.8.13 Distribution Substations

Distribution substations comprise the transformer (which are sub-categorised in the section below), transformer pad, HV and LV fusing and an earth mat. At 1 April 2007, there were 6,063 distribution substations on the Aurora network.

Eleven pedestal-mounted transformers on the Central network are at risk in the event of a significant earthquake and present a safety hazard. It is planned to have all of these replaced by June 2009.

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

3.8.14 Distribution Transformers

Figure 3.17 details the age profile of distribution transformers Aurora has in service. The age of only 50 units (0.8%) is unknown. While approximately 5% of the transformer population is older than the extended OLV life of 55 years, there is no history of age-related failures. Accordingly, only routine inspections and monitoring are necessary.

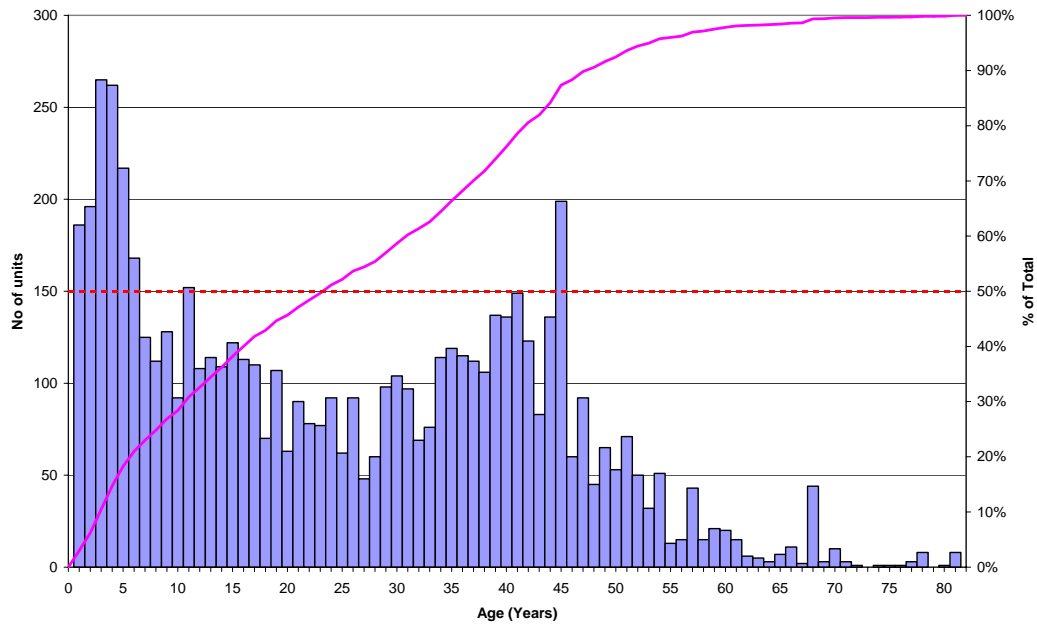


Figure 3.17 – Installed Distribution Transformers Age Profile (Total = 6220)

3.8.15 HV Regulators

Figure 3.18 details the age profile of regulators. This age profile is by regulator site i.e. a site with three single phase regulators is treated as one unit.

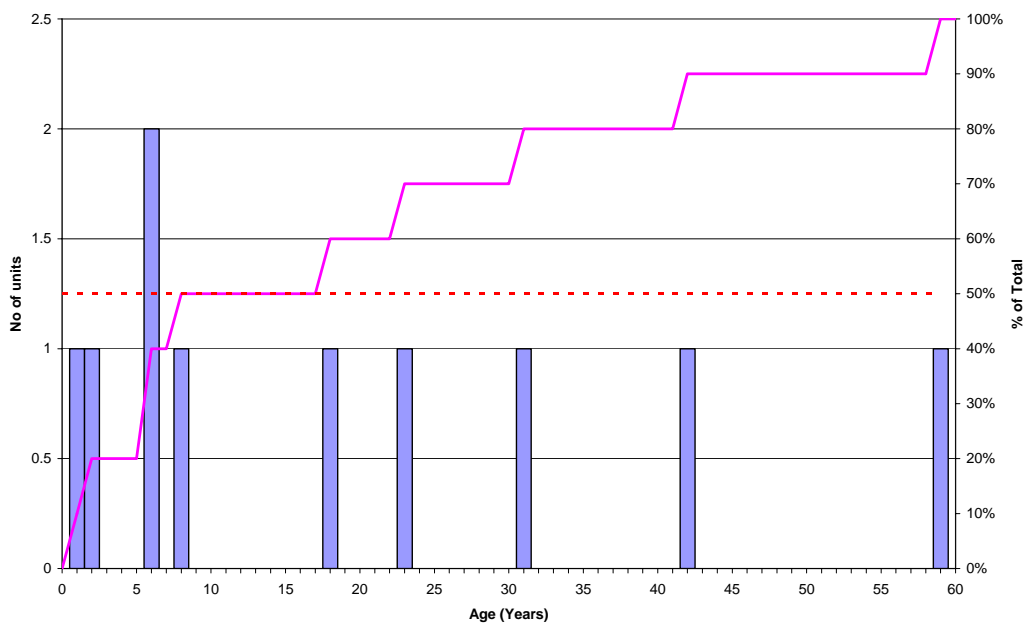


Figure 3.18 – HV Regulators Age Profile (10 Sites)

3.8.16 HV Auto-Transformers

Figure 3.19 details the age profile of the auto transformers. Nine auto transformers (with a spare unit available) are used for the interconnection of 11kV and 6.6kV sections of the network. While these units have an average age of greater than 35 years, they have been reliable and only require minimal maintenance.

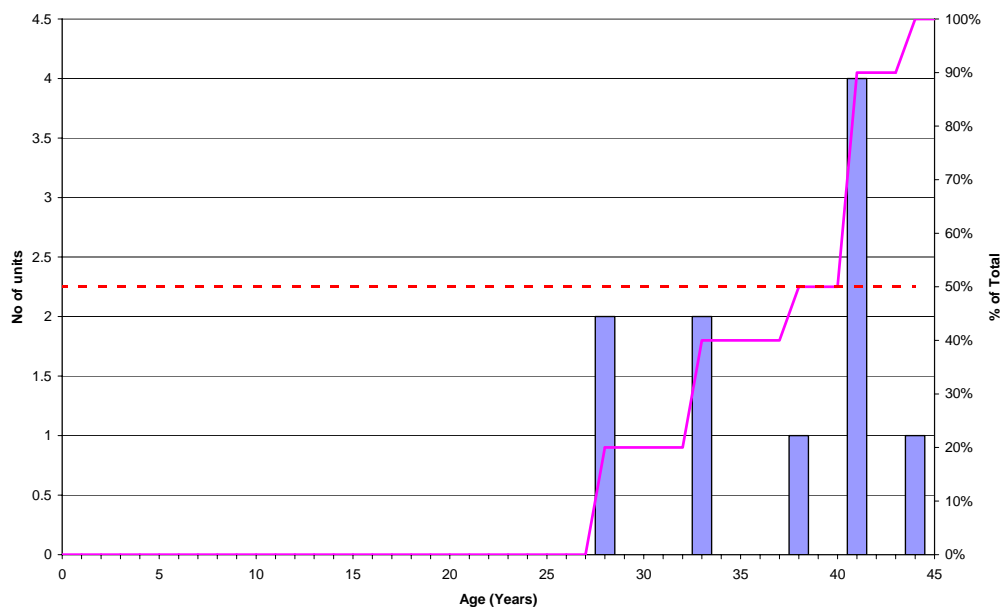


Figure 3.19 – HV Autotransformers Age Profile (10 Units)

3.8.17 HV Ground Mounted Distribution Switchgear

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

The age profile of ground mounted distribution switchgear is shown in Figure 3.20. Age data is not available for 13% of the units.

Two recent failures of Statter VL switchgear have resulted in the replacement of these at one major 11kV consumer site over the 2007/08 summer.

Switchgear Type	No of Units
Ground mounted 3 phase air fuse unit	110
HV oil ring main unit	470
HV oil fuse switch	231
Oil circuit breaker	32
Single HV oil switch	368
Vacuum circuit breaker	7
Total	1,218

Table 3.13 - Ground Mounted Switchgear by Type

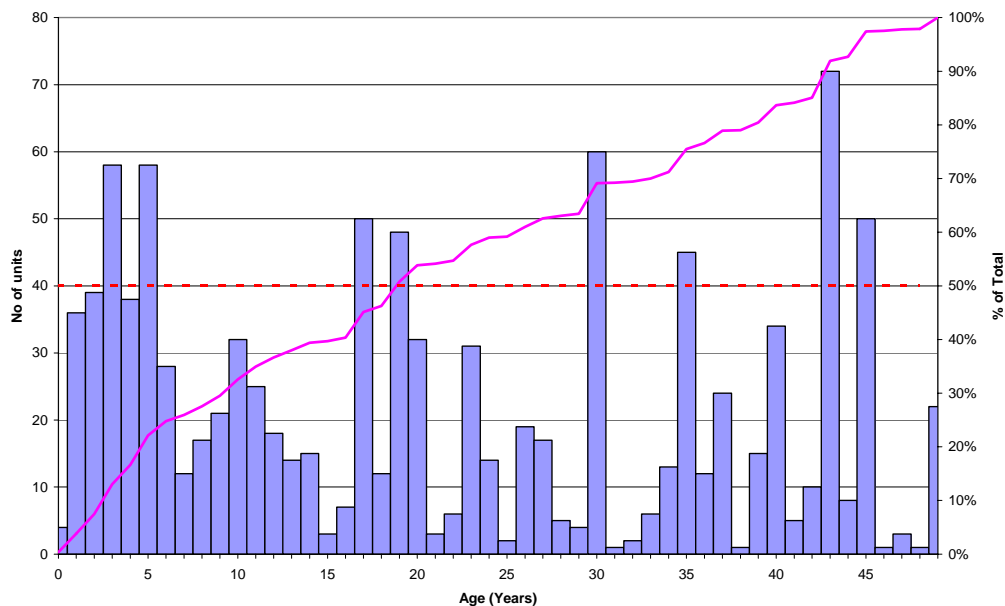


Figure 3.20 – HV Ground Mounted Switchgear Age Profile

3.8.18 LV Overhead Conductor

Figure 3.21 shows the age profile of overhead LV lines. Aurora has 1050km of LV line and the construction date of 182 km (14%) has yet to be confirmed. There are two types of LV overhead on the network, aerial bundled conductor (ABC – which is rarely used) and open wire on pin insulators.

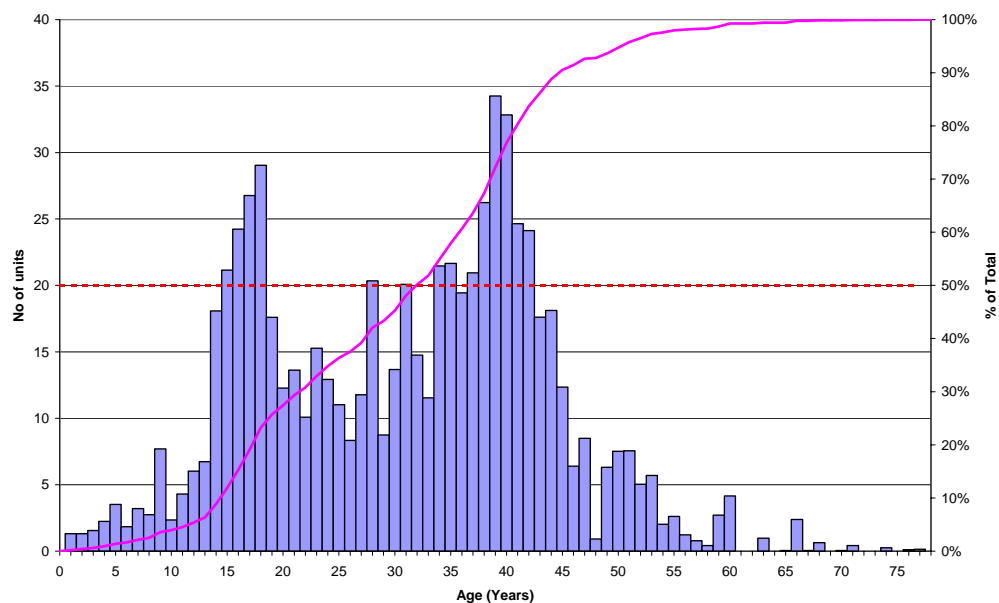


Figure 3.21 – LV Distribution Line Age Profile

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

Part of the grouping at the 17 year age group is due to default date data which is to be corrected.

3.8.19 LV Underground

Figure 3.22 shows the age profile of the underground cables. Aurora has 675 km of LV cable of which the age of 69 km (10%) has yet to be confirmed as dating from original construction. Most LV cable is cross linked polyethylene (XLPE). However, in the Dunedin CBD, paper-insulated lead covered (PILC) cable has been the norm.

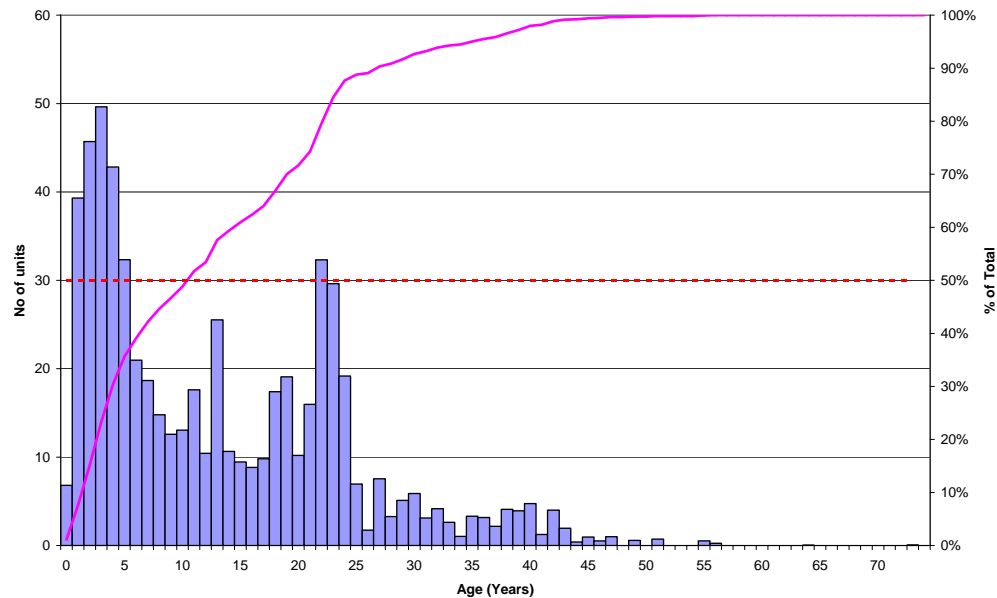


Figure 3.22 – LV Distribution Cable Age Profile

The recent boom in residential subdivision is evident.

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

3.8.20 Poles

Aurora has approximately 50,200 poles of which only 477 (1%) poles do not have installation dates allocated.

Figure 3.23 details the age profile.

A condition-based inspection regime is in place which indicates that the rate of renewal will double at least by the end of the planning period. Since 1990, softwood poles have been used as replacements for both concrete and hardwood poles but questions arose as to their longevity in the Central Otago environment due to excessive twisting. Investigation has confirmed that, as long as softwood poles are selected based on strict criteria, they should have an acceptable life.

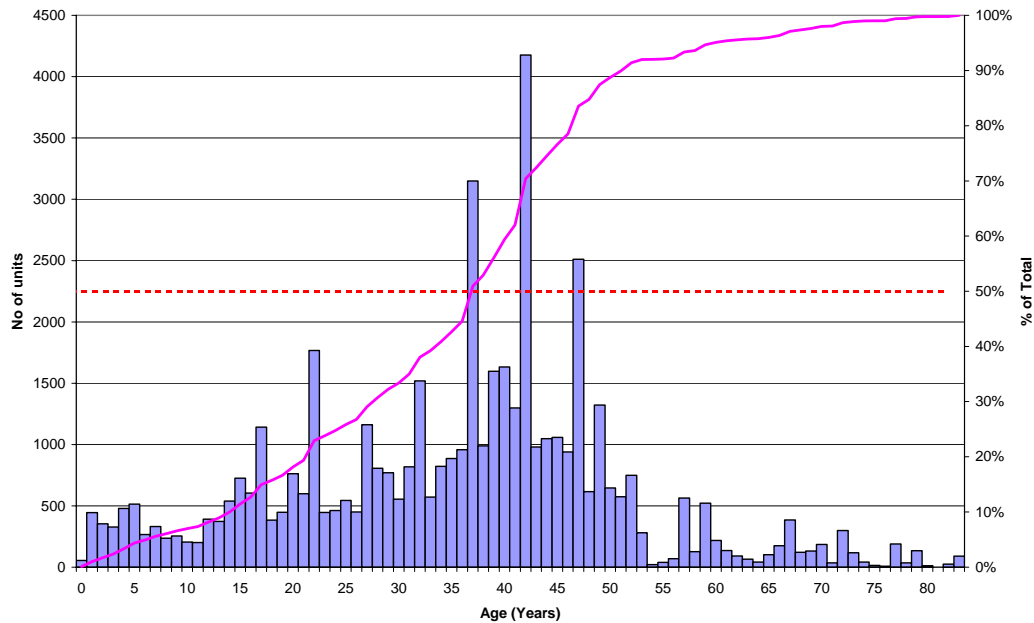


Figure 3.23 – Poles Age Profile

3.8.21 System Control Equipment

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

3.9 Justification for Assets

All assets are justified by present or anticipated requirements except for approximately 3.2% of assets by ODV value which have been “optimised” out for ODV purposes. Although such assets have been optimised out, many are still required to meet existing network standards (for example - fault limiting reactors). These assets require on-going monitoring and maintenance and, as such, represent a cost to the network. Until the cost of maintaining the status quo becomes higher than the cost to replace with the optimal network, these present network assets will remain in service.

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

- The need to accommodate future demand growth (noting that the ODV Handbook prescribes the number of years ahead that such growth can be accommodated).
- How asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.
- The asymmetric nature of under-investment and over-investment to be clearly understood i.e. over-investing creates service levels before they are needed, but under-investing can lead to service interruptions.
- The discrete “sizes” of many classes of components to be recognised; for example, a 220kVA load will require a 300kVA transformer that would be only 73% loaded. In some cases capacity can be staged through use of modular components.

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

Assets that were optimised are detailed below:

HV Distribution Switchgear

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

HV Distribution

HV distribution lines and cables that were identified in the GIS as being “not in service” were optimised out. Typically these are cables that have been laid in conjunction with other utility assets to minimise public inconvenience by avoiding the need to re-trench roads at a later date. The total quantity optimised was 10.6 km (13.5 km previously) in the Central area and 0.84 km in the Dunedin area. The Central area data, which relates to a historic GIS system is being checked and corrected as can be seen by the reduction in length above.

LV Distribution

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

Subtransmission

One of three circuits to the South City substation was optimised out because there are now only two transformers at South City. Ward Street and Neville Street cables were optimised to a shorter length to reflect new construction which would supply these substations from the South Dunedin GXP instead of the Halfway Bush GXP.

Pilots

32.9 km of pilot cables were optimised out in the Dunedin area.

Zone Substation Assets

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

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

One circuit breaker at the Cromwell substation was optimised out.

Buildings at Neville Street and Ward Street were optimised to a smaller size. The South City building was optimised to a value two thirds of its replacement cost to recognise that a replacement building would only accommodate two transformers and twelve outgoing feeders. Unused HV feeder circuit breakers (19) were optimised out.

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

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

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

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

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

4 Service Levels

4.1 Consumer Oriented Performance Targets

4.1.1 Network Performance

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

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

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

At a practical level, however, the ability to improve Aurora's network reliability in rural areas is constrained by the topography and the low density of connections.

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

Period End 31 March	2003/04	2004/05	2005/06	2006/07	2007/08
Unplanned					
Underlying	56.6	67.8	70.8	61.3	55.3
Significant Events	23.4	5.4	0	22.3	60.7
Transpower	1.0	0.0	13.9	4.7	11.0
Total Unplanned	81.0	73.2	84.7	88.2	127.0
Planned					
Underlying	16.3	7.3	11.7	13.2	13.3
Total					
Underlying	72.9	75.1	82.5	74.5	68.6
Significant Events	23.4	5.4	0	22.2	60.7
Transpower	1.0	0.0	13.9	4.7	11.0
Disclosure Total	97.3	80.5	96.4	101.4	140.3
Other (LV etc)	0.1	0.9	0.5	0.5	1.4
Overall Total	97.4	81.4	96.9	101.9	141.7

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

As detailed elsewhere, *the intention is to reduce SAIDI by one minute per year*, at the levels shown in Table 4.2. Analysis of the reliability data for other distribution networks in New Zealand reveals a present (2007) average figure of 176 minutes without supply per consumer per year.

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Unplanned	73	72	71	71	70	69	68	68	67	66
Planned	15	15	15	14	14	14	14	13	13	13
Total	88	87	86	85	84	83	82	81	80	79

Table 4.2 – Network Performance Target (SAIDI) (minutes)

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

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

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Unplanned	1.33	1.31	1.29	1.27	1.26	1.25	1.24	1.24	1.22	1.20

Table 4.3 – Network Performance Target (SAIFI)

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

4.1.2 Restoration of Electricity Delivery and Service Interruption Investigations

Restoration of electricity delivery following a general network failure

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

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

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

Service failure payments relating to 1,001 ICPs were made in the year ending 31 March 2008.

Frequency of interruptions following a general network failure

Aurora has the following targets:

- (i) urban areas – no more than 4 interruptions per annum
- (ii) rural areas – no more than 10 interruptions per annum
- (iii) remote rural areas – no more than 20 interruptions per annum.

In the year ending 31 March 2008, 4,107 (6%) urban consumers experienced more than four interruptions and 2,863 (26%) rural consumers experienced more than 10 interruptions. Most of the rural consumers experiencing high numbers of interruptions are supplied from reclosers and, hence, many of the interruptions will be for relatively short periods.

Power Quality or Service Interruption Investigations

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

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

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

From a distributor's perspective, it can be measured in economic terms. Monitoring of the cost of maintenance and repair of assets, together with the assessed cost of non-supply arising from the failure of assets, and measurement against the replacement cost of those assets, is an integral part of Aurora's asset management practice. Physical asset performance targets, such as faults per 100 km of conductor, are supply side measures and are secondary to SAIFI; however, they do provide segmented information to assist distributors when making asset management decisions. A full list of Aurora's asset performance targets are listed in Appendix B.

4.2.1 Voltage Range

A minimum and maximum voltage is set by statutory requirement for the protection of consumer appliances, but excludes "momentary" fluctuations. Voltage excursions outside of the statutory range will occur because of equipment failure, environmental effects (for example - lightning) or unexpected loads and all can require solutions that take time. Voltage excursions will normally be reported by consumers and will normally be for low voltage, due to rising loads or failing conductor joints, and reported during winter when loads are highest. Often the problem has abated, until the following winter, before Aurora can confirm the cause or make additional investment where this is necessary. Accordingly, Aurora sets a target for the maximum number of outstanding voltage complaints of ten per ten thousand consumers per annum and, when alerted to voltage excursions, sets a time target for solution at 31 December each year. These targets are set against good industry practice. The usual impediment to meeting this target is gaining Local Authority agreement as to where to locate equipment such as additional transformers required to improve localised voltage complaints.

4.2.2 Supply Interruption

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

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

Many distributors have adopted the tabular form of security guideline. This is a useful rule-of-thumb approach to network design, but it is dependent on engineers' perceptions of consumers' needs (for example - larger load groups and "urban" feeders are generally assigned higher standards without the basis of the choice being explicit). Such a deterministic approach was used in the past by Aurora for the Dunedin City area, but has been replaced by a demand-side-driven probabilistic approach. This approach is more sophisticated, is facilitated by technology available today and, in Aurora's view, will lead to better asset utilisation and, thus, lower costs while meeting consumer expectations. Because this process requires user-input, it is described here in some detail.

Step 1 - Determine What Users Want

User opinion on quality of supply issues is continuously surveyed by Aurora. The survey was commenced in 1999 and is continuous both so that results are less affected by long periods without supply interruption, or by significant interruption, at the time the survey is conducted with a given consumer, and so that the result evolves with changes in network performance. It is conducted directly with consumers because retailers appear to have little focus on quality issues at present and because retailers may prove unable to reflect local preferences in the long term.

Results to date can be summarised as follows:

Aurora's Continuous Price Versus Quality Survey						
Results to 31 March	2003	2004	2005	2006	2007	2008
Consumers Surveyed	4,327	4,554	4,641	4,603	4,752	4,000
Response Rate	20%	18%	18%	18%	16%	18%
Responses						
Prefer higher quality	9.3%	7.4%	6.7%	5.3%	5.9%	4.8%
Prefer lower price	90.7%	92.6%	93.3%	94.7%	94.1%	95.2%

Table 4.4 – Price Versus Quality Survey

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

Aurora's Customer Telephone Survey 2008 and 2006							
No	Question	Dunedin		Central		Total	
		2006	2008	2006	2008	2006	2008
1	Price more important than quality	Yes 68%	65%	Yes 86%	59%	Yes 77%	62%
		Unsure 15%	11%	Unsure 2%	16%	Unsure 8%	14%
		No 17%	24%	No 12%	25%	No 15%	24%
2	Single most important issue relating to quality ³	No of interruptions 70%	40%	No of interruptions 71%	46%	No of interruptions 71%	43%

³ Slight change in questionnaire for 2008 means comparison with 2006 not totally similar but reasonable approximation.

Aurora's Customer Telephone Survey 2008 and 2006							
No	Question	Dunedin		Central		Total	
		2006	2008	2006	2008	2006	2008
3	Accept 10% increase in line charges for 10% improvement in quality ⁴	No 68% Unsure 12%	100% 0%	No 75% Unsure 4%	46% 0%	No 71% Unsure 9%	70% 0%
4	Acceptance of rebate should increased supply not be achieved	Yes 68% Unsure 12%	60% 10%	Yes 88% Unsure 4%	92% 0%	Yes 76% Unsure 9%	78% 5%
5	Accept 10% decrease in line charges for say 10% more interruptions ⁴	No 44% Unsure 16%	81% 4%	No 80% Unsure 4%	77% 7%	No 64% Unsure 9%	79% 6%
6	Acceptable time-frame for restoration of supply (weighted avg)	2.8 hrs	2.2 hrs	1.6 hrs	2.6 hrs	2.2 hrs	2.4 hrs

While the continuous survey results strongly imply 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, thus, relatively invisible to customers. In addition, the results from the telephone survey confirmed that price is more important than quality and few consumers wished to pay higher line charges for higher quality. Conversely, lower line charges for lower quality were also not desired by a majority. The expected restoration time by customers in Central Otago had increased and is now just above that for Dunedin. Perhaps fewer of the surveyed customers in Central Otago would have experienced unplanned interruptions in the last year. A continuing trend in both areas is that the number of interruptions remains the highest issue relating to reliability.

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 (for example - interruptible load, load storage, on-site generation) will also be available to the consumer at their own investment cost. Conversely, there is no case for the majority of consumers paying for higher quality than they require.

Step 2 - Determine the Probability of Interruption

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

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

Step 3 - Put a Value on Avoidance of Interruption

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

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

Table 4.5 – Valuation of Interruption

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

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

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

Step 4 - Discovering Economic Opportunities

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

4.2.3 Interruption Targets

Until quality issues have been more widely debated with network users, the main measure chosen to monitor overall asset performance is the System Average Interruption Duration Index (SAIDI), since it combines both interruption frequency and interruption duration, and the plan provides to improve it incrementally by reducing SAIFI especially for those consumers that experience high levels of interruption.

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

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

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

4.2.4 Frequency of Interruption

An acceptable overall level of SAIDI can disguise local reliability that is significantly worse than average. For some years, Aurora has monitored "FAIDI" (feeder customer-minutes divided by feeder customer number, for each feeder) to ensure that the performance of the worst feeders is apparent. For "problem feeders" consumers are more sensitive to frequency of interruptions, and this is receiving specific attention. Examples of such analysis are shown in located in Section 5.14.1 of this AMP.

4.2.5 Customer Service

Particularly because Aurora has contracted out management of its assets, Aurora ensures appropriate customer service for such matters as answering telephones and correspondence by monitoring *DELTA's* performance. Aurora is also a founding member in the Electricity and Gas Complaints Commission scheme and is committed to resolving consumer issues in a responsible manner.

4.2.6 Safety Performance

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

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

One report of electric shock in 2003 resulted from poor earth installation. There have been no other confirmed reported instances in recent years.

4.2.7 Environmental Responsibility Performance

Many of Aurora's assets are in environmentally sensitive areas. Maintenance programmes include the repair and maintenance of oil filled equipment such as transformers and circuit breakers to prevent leakages, the upkeep of noise-reducing components, and appropriate landscaping and/or revision of land usage. A programme to install oil containment bunds around Dunedin zone substation transformers was completed in 1997 and distribution transformer storage areas in 1998. Not all of the Central zone substations have bunding and this is being addressed. A specific instruction covers the handling of sulphur hexafluoride (SF₆) gas used as an insulating medium in some equipment. Polychlorinated biphenyls (PCBs) have been eliminated from Aurora's equipment. No breaches of the RMA have occurred.

5 Network Development

5.1 Introduction

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

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

Aurora expects strong growth in electrical demand to continue in the areas served by the Frankton (4.1% growth p.a.) and Cromwell (5.6% growth p.a.) GXPs. There are a variety of forecasts that indicate growth could continue at these levels or could fall. The projected capital budget below reflects a continued growth scenario so the predominant reason for capital expenditure is network extensions and upsizing demand capacity.

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

Minimal population growth is expected in Dunedin over the next 20 years. Overall growth in electrical demand is expected to average between 0.5% and 1% but there will be localised areas where growth will exceed this. Capital expenditure in the Dunedin area will mainly be driven by the replacement of ageing assets, the conversion of overhead distribution to underground and reliability improvements.

Aurora's projected capital expenditure is presented in Table 5.1 below in nominal dollar terms, so that constant amounts represent reducing real-cost expenditure.

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
New customers	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Local growth including renewals	3,400	3,400	3,400	3,400	3,400	3,400	3,100	3,100	3,100	3,100
System development including SCADA	950	700	700	700	700	700	700	700	700	700
Subtransmission and zone substations	4,700	3,500	3,410	4,250	4,640	5,050	5,070	6,060	5,550	5,550
Undergrounding	2,370	2,410	2,450	2,490	2,530	2,580	2,630	2,680	2,730	2,780
Total	19,260	18,210	18,160	19,040	19,470	19,930	20,400	20,740	20,280	20,330

Table 5.1 – Capital Expenditure Forecast (\$000)

Expenditure definitions are as follows:

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

The subtransmission and zone substation provision covers potential projects subject to final economic analysis. Specific projects currently under final investigation are described in Section 5 and include:

- Morven Ferry Road substation (5.11.2)
- Mosgiel zone substation (5.11.3)
- Frankton zone substation (5.11.5)
- Ward Street substation replacement (6.5.2).

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

5.2 Distributed Generation Policy

Distributed generation schemes have the potential to make a significant contribution to future network development in terms of security, efficiency and economy of network operation. Aurora encourages the connection of distributed generation to its network and examines each proposal with regard to strategic network development. Aurora currently has in excess of 60MW of embedded generation, albeit hydro developed before the 1998 Electricity reforms.

Aurora has guidelines for the connection of small distributed generation published on its website at www.electricity.co.nz. For the connection of larger capacity generation, the New Zealand Electricity Engineers Association's guidelines are followed and application information required is also published on www.electricity.co.nz. These comply with the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

Aurora's Congestion Period Demand (CPD) pricing methodology financially rewards the operation of standby generation plant during network congestion periods. Aurora applies the "Principles for the Connection of Distributed Generation to a Network" as published in the Electricity Governance (Connection of Distributed Generation) Regulations

Aurora has investigated the installation of generation to defer transmission upgrades and has identified that the most economic method to support the winter peak loads in the Cardrona valley will be by the installation of diesel generation. This is being installed in the 2008/09 year.

5.3 Non-Network Solutions

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

Ripple signal injection is used to signal congestion periods and to offer an appliance-switching service that is voluntary but financially attractive. The switching service is predominately used for water heating, space heating and pumping loads and results in peak demand being reduced by approximately 45MW (16%) across the Dunedin and Central networks requiring that much less investment in network capacity.

Distributed generation is encouraged to operate during congestion periods and this is facilitated by the CPD ripple signal.

5.4 Planning Criteria

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

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

Probabilistic analysis is also applied at the HV feeder level. The trigger for analysis is when it is not possible to fully off-load a feeder onto adjacent feeders at peak load or the feeder has reached 85% of its thermal rating. On rural feeders, it is normally voltage drop that will determine the maximum capacity of a feeder, whereas it is thermal capacity that is normally the limit in urban areas.

5.5 Planning Process

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

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

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. In reality, the do nothing option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if analysis was provided to the Chief Executive and Directors that the do nothing option did not represent an unacceptable increase in risk to the business.
- Operational activities, in particular switching the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment.
- Influence consumers to alter their consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity.
- Construct distributed generation so that an adjacent assets performance is restored to a level below their trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. water being released from a dam that could be used in a hydro generator.
- Modify an asset so that the trigger point will move to a level that is not exceeded eg by adding forced cooling. This is essentially a sub-set of the final approach described below, but will generally involve less expenditure. This approach is more suited to larger classes of assets such as 33/11kV transformers.

- Retrofitting high-technology devices that can exploit the features of existing assets. Examples might be using remotely switched air-breaks to improve reliability, using advanced software to thermally re-rate heavily-loaded lines, or retrofitting core temperature sensors on large transformers.
- Install new assets with a greater capacity that will increase the assets trigger point to a level at which it is not exceeded.

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

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

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

5.6 Demand Forecasting Methodology

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

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

5.7 Project Prioritisation Methodology

In general the priority for the completion of capital projects is in accordance with Table 5.2.

Priority	Project Category
1	Projects to eliminate significant health and safety issues.
2	Projects to resolve consumer voltage outside statutory limits.
3	Consumer driven projects such as new connections and subdivisions.
4	Projects to provide for load growth.
5	Projects to improve reliability that are not related to load growth. Projects in this group with the highest expected benefit to cost ratio are implemented first.
6	Overhead to underground conversion projects.
7	Renewal projects where there is no immediate threat to network reliability or health and safety issues.

Table 5.2 – Project Priority List

Projects described in section 5 are listed in Appendix A.

5.8 Equipment Ratings

Equipment ratings are assigned in accordance with Table 5.3.

Equipment	Rating Allocation
Zone substation transformers ONAN	Transformers are operated to 120% of nominal rating by taking advantage of low ambient temperature during high load periods and cyclic load profile as per AS 23747 "Loading guide for oil immersed transformers".
Transformers ONAN/OFAF	Manufacturer assigned emergency rating.
Overhead lines	Winter night and summer day ratings assigned in accordance with IEEE Std 738 -1993. See Table 5.4 for parameter allocation.
Switchgear	Manufacturer's assigned rating, no overload permitted.
Current transformers	120% of nominal rating unless rated for extended thermal range.
Cables	Some 33kV cables have had ratings assigned by consultants after investigation of specific installation conditions. For all other cables the manufacturer's standard data sheet ratings are used including ambient temperature, soil thermal resistivity and cable proximity.
Distribution transformers	Transformers with a normal residential area load profile can be loaded to 150% of nominal rating. For other loads 130% of nominal rating.

Table 5.3 – Assignment of Equipment Ratings

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

Table 5.4 – Parameters Used to Determine Overhead ACSR Conductor Ratings

5.9 Grid Exit Points

5.9.1 Demands and Growth Predictions

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

Calendar Year			Clyde	Cromwell	Frankton	Halfway Bush	South Dunedin
2000	Actual	GXP Off take + Embedded Generation (MW)	16.4	18.4	34.6	123.0	62.4
2001			17.1	21.0	38.3	135.7	62.1
2002			17.1	19.9	37.4	133.0	65.9
2003			15.2	20.3	38.3	116.4	61.3
2004			15.6	21.5	41.4	126.0	67.0
2005			17.2	24.4	41.8	126.0	66.1
2006			16.3	25.1	45.1	125.1	70.2
2007			18.2	30.6	49.7	130.6	71.0
2008	Predicted		17.6	29.4	49.6	127.9	71.6
2009			17.9	31.2	51.9	128.5	73.0
2010			18.2	33.2	54.3	129.1	74.4
2011			18.4	35.2	56.8	129.8	75.8
2012			18.7	337.4	59.4	130.4	77.3
2013			19.0	39.8	62.1	131.0	78.8
2014			19.4	42.3	64.9	131.7	80.3
2015			19.6	44.9	67.9	132.3	81.9
2016			20.0	47.7	71.0	133.0	83.5
2017			20.3	50.7	74.2	133.6	85.1
2018			20.6	53.8	77.6	134.3	86.7
Past Growth Rate (Trend 2000 to 2007)			1.6%	6.2%	4.6%	0.5%	1.9%
2007 MW off take peak (excludes embedded generation)			9.2	27.3	48.3	109.7	71.0
Off take n-1 Capacity (Continuous) MVA			27	356	66	100	81
Off take n-1 Capacity (24hr Winter Post Contingency) MVA			27	35	88	112	81
Embedded Generation (2007 MW at time of load peak)			12.9	3.3	1.3	24.0	n/a

Table 5.5 – GXP Area Peak Demands

Strong growth is predicted to continue in the Frankton and Cromwell GXP areas and more modest growth in the Clyde and Dunedin GXP areas. The South Dunedin demand growth has been predicted to be 1.0% as the apparent load growth of 1.7% was partly due to a 2MW load transfer from the Halfway Bush GXP in 2006.

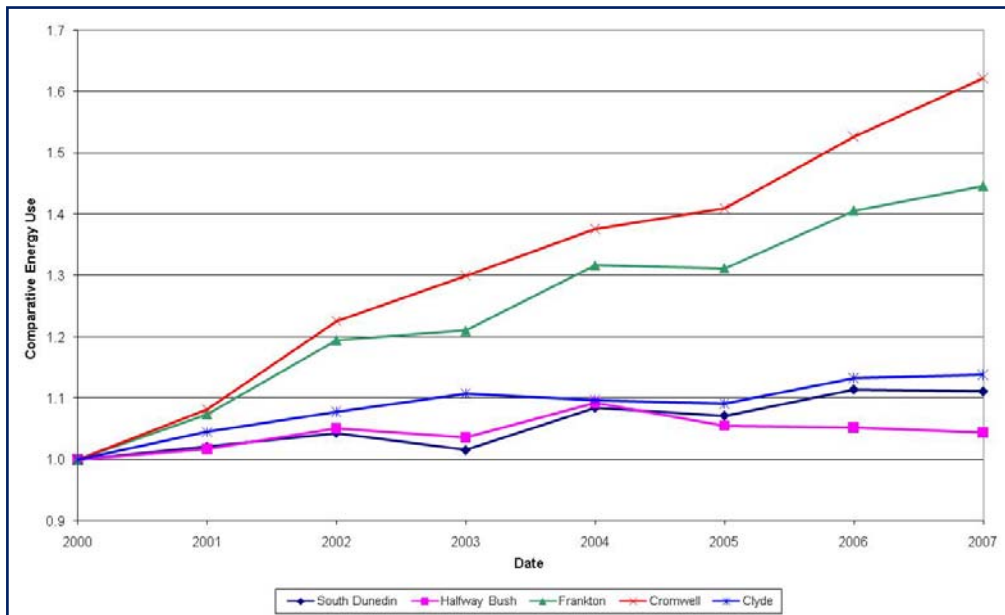


Figure 5.1 – Comparative Growth in GXP Energy (GWh 2000 Normalised)

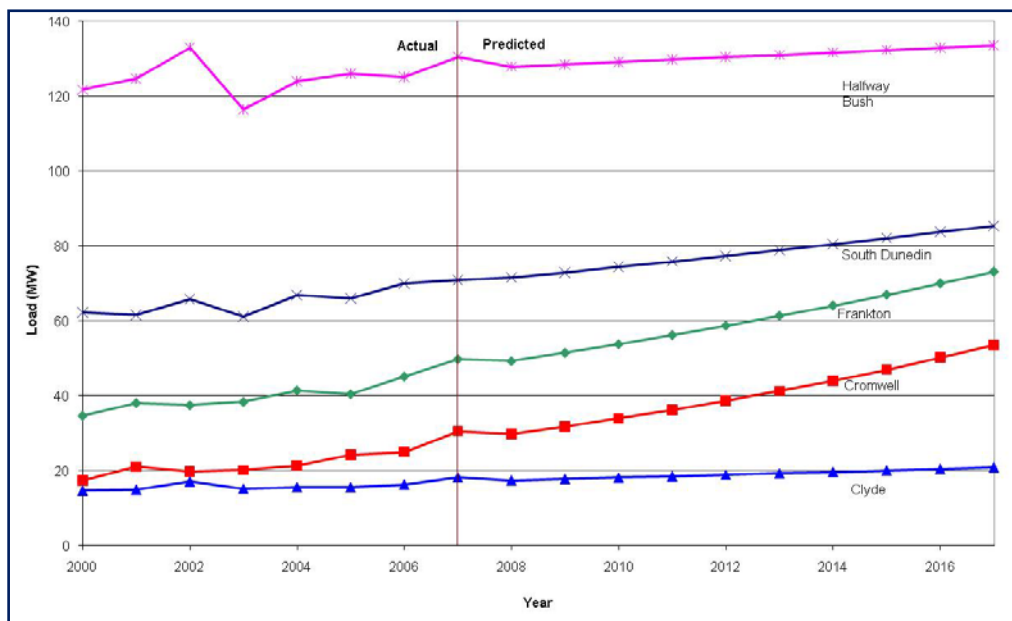


Figure 5.2 – GXP Area Peak Demands (Including Embedded Generation)

The reduction of demand in Dunedin and Clyde 2003 was due to the government's energy savings campaign. The Dunedin 2002 peaks were due to an uncharacteristic three-day snowfall in May.

5.9.2 Frankton GXP

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

The 2007 peak off take on the Frankton GXP was 49.7MW (excluding embedded generation).

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

5.9.3 Cromwell GXP

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

It is expected that the nominal 50 MVA rating on the 110 kV winding feeding Frankton will be exceeded in the winter of 2009. The proposed upgrade option is to parallel the existing transformers on one circuit and install a new 220/110/33 kV, 150/150/50 MVA transformer on the other circuit. Aurora has signed a New Investment Agreement with Transpower to proceed with the selected upgrade option and completion is expected by April 2009.

5.9.4 Clyde GXP

The Clyde GXP has two 27 MVA transformers. The embedded generation on this GXP almost meets the total demand on GXP. Should the embedded generation fail the maximum demand on the GXP would be approximately 19 MVA, based on 2007 loadings. There is adequate GXP capacity at Clyde for the foreseeable future. Growth has been lower than the above GXPs in the Clyde area and is not expected to accelerate during the planning period.

During June 2006, one of the Clyde GXP transformers failed and was eventually recommissioned in November 2007.

5.9.5 Halfway Bush GXP

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

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

5.9.6 South Dunedin GXP

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

5.10 Subtransmission

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

5.10.1 Frankton to Queenstown

The n-1 capacity of the 33kV subtransmission from the Frankton GXP to Queenstown was constrained by the 33kV cables into the Queenstown substation. This is to be resolved by upgrading the cables before the winter of 2008. New cables from the Frankton GXP to the Frankton zone substation have been completed as part of the Frankton GXP upgrade.

5.10.2 Cardrona Valley

Demand in the Cardrona valley is increasing due to the expansion of ski fields and subdivision activity in the area. Demand in the valley is near the maximum of 2MVA that can be supported by the 11kV line and voltage regulators. A 500kW diesel generator is being installed before the 2008 winter to support the 11kV voltage. The generator would be operated during the ski season until it is economic to install a 33kV substation.

5.10.3 Wanaka to Hawea

Contact Energy proposes to install 16MW of hydro generation at Lake Hawea and has obtained resource consent. Subtransmission upgrade and new lines will be required between Wanaka and Hawea. It is proposed that the new line follows the route of the existing 11kV line in a 66kV over 11kV configuration. Contact's preliminary timetable requires confirmation. Resource and land owner consent will be required for this project. The estimated cost is \$1,000,000.

5.10.4 Nevis Power Scheme

Pioneer Generation Limited is investigating a 40MW hydro generation station on the Nevis River and has enquired about options for connection to the Aurora network. Indicative costs have been given to Pioneer (in 2005) who also has the option of connecting to the nearby Transpower 110kV lines.

5.10.5 Maungatua Wind Farm

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

5.10.6 Other Major Projects

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

5.11 Zone Substations

5.11.1 Demand Projections

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

The *n-1 capacity* is the maximum load a substation can supply in the event of the failure of any one item of substation equipment without the need to transfer any load from the substation. The *firm capacity* is the maximum load a substation can carry with the largest transformer out of service and up to 6 MVA of load transfer to adjacent substations. It will generally take at least an hour to transfer load from the zone substation. During this hour the in service transformer and associated equipment must be capable of carrying the allocated firm capacity. Where the load limitation is HV switchgear that has no overload capability the firm load can be restricted to the same as the n-1 load.

Predicted future demands are shown with a shaded background when they exceed the firm capacity of the substation and these act as a “flag” for closer study. Zone substations with a capacity of 3 MVA or less are not designed to n-1 security. Spare transformers are held that provide cover for several sites.

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

Smith Street and South City

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

Mosgiel and East Taieri

The previous load growth rate is only based on the last three years, due to load transfer between these substations occurring prior to the 2003 winter. A combined firm load of 30.8 MW has been allocated due to the flexibility with which load can be transferred between these substations and their mutual dependence on the subtransmission. If a Mosgiel transformer was lost, then load transfers to East Taieri would be adequate to serve load up to 2009. Closing the 33 kV bus at Mosgiel would increased the combined firm load (see Section 5.11.3).

North City

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

Queenstown, Commonage and Fernhill

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

				Historical Demands MVA								Predictions			Predicted Demands Between Exp and Linear										
Zone Substation	Transformer MVA	Firm Load MVA	n-1	2001	2002	2003	2004	2005	2006	2007	Previous Growth (Exp) %/yr	Exponential Growth %/yr	Linear Growth MW/yr	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Alexandra	7.5/15+7.5/15	15	15	10.8	11.1	10.0	10.4	10.8	10.9	12.4	1.64%	1.6%	0.20	11.6	11.8	12.0	12.2	12.4	12.6	12.8	13.0	13.3	13.5	13.7	
Anderson's Bay	15 + 15	18	18	15.8	15.5	13.5	15.3	14.6	14.9	16.6	0.53%	0.5%	0.08	15.5	15.6	15.6	15.7	15.8	15.9	16.0	16.1	16.1	16.2	16.3	
Arrowtown	5 + 5	7.5	6	6	5.6	6.3	6.3	6.4	7.2	7.7	4.63%	4.6%	0.30	7.7	8.1	8.4	8.7	9.1	9.5	9.8	10.2	10.6	11.0	11.4	
Berwick	0.9+0.9	2	0	0.9	1.2	1.2	1.1	1.1	1.1	1.2	2.47%	2.5%	0.02	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.5	1.5	
Clyde/Earnsclough	4 +2	4.8	4	4.1	4.7	4.1	3.6	3.6	3.7	3.6	-3.50%	1.0%	0.03	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	
Coronet Peak	5	6	0	0	0	0	3.0	4.4	3.6	3.6	3.09%	0.5%	0.18	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	
Corstorphine	12/24 + 12/24	23	23	13	13.5	12.2	13.1	12.5	12.8	13.8	0.35%	0.3%	0.05	13.2	13.2	13.3	13.3	13.4	13.4	13.5	13.5	13.6	13.6	13.6	
Cromwell	5/10 + 7.5	9.0	9.0	6.2	6	6.6	7.1	6.8	7.9	9.2	6.50%	6.5%	0.46	9.0	9.5	10.1	10.6	11.2	11.8	12.5	13.1	13.8	14.5	15.3	
Dalefield	3	3.6	0	3	3.0	3.0	1.4	1.9	1.8	2.3	15.43%	5.0%	0.11	2.4	2.5	2.6	2.7	2.8	3.0	3.1	3.2	3.4	3.5	3.7	
Earnsclough	2	Used to increase Clyde/Earnsclough firm capacity to 4.8MVA												0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
East Taieri	12/24 + 12/24	See Text	18.5	13.4	14.7	13.6	14.2	14.9	15.7	15.7	2.52%	2.5%	0.36	16.1	16.5	16.8	17.2	17.6	18.0	18.5	18.9	19.3	19.7	20.2	
Ettrick	3	3.6	0	1.6	2.0	2.0	1.8	2.0	1.5	2.0	0.34%	0.3%	0.01	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	
Frankton	7.5/15 +7.5/10	12	10	7.7	7.9	7.8	8.0	9.0	10.4	12.0	7.46%	4.0%	0.44	10.9	11.4	11.8	10.1	10.5	10.9	11.4	11.8	12.3	12.7	13.2	
Fernhill	7.5/10+7.5/10	10	10	5.1	4.8	5.2	5.2	5.4	5.6	6.1	3.20%	3.2%	0.17	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8	8.0	
Green Island	15 + 15	18	18	13	12.5	12.9	13.6	13.8	14.0	14.2	2.02%	2.0%	0.27	14.5	14.8	15.1	15.4	15.7	15.9	16.2	16.5	16.8	17.2	17.5	
Halfway Bush	15 + 15	18	18	14	14.1	12.2	12.3	13.1	13.6	14.2	0.15%	0.1%	0.02	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.6	13.6	13.6	13.6	
Kaikorai Val.	12/24 + 12/24	23	22	11.8	9.0	9.0	10.0	11.9	10.3	10.4	0.61%	0.6%	0.05	10.5	10.6	10.6	10.7	10.8	10.8	10.9	10.9	11.0	11.0	11.1	
Maungawera	3	3.6	0	1.9	2.3	1.9	2.2	2.3	2.5	3.2	6.96%	7.0%	0.16	2.8	3.0	3.2	3.4	3.6	3.8	4.0	4.3	4.5	4.8	5.0	
Mosgiel	10 + 10	14	12	14	12.0	11.0	11.6	11.8	12.2	12.0	-1.27%	1.0%	0.11	11.7	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	
Neville St	15 + 15	18	18	14.2	13.6	13.0	13.6	13.9	14.4	14.9	1.17%	1.2%	0.16	14.6	14.8	14.9	15.1	15.3	15.4	15.6	15.8	16.0	16.1	16.3	
North City	14/28 +14/28	28	28	21	21.1	21.1	20.4	19.8	20.2	20.7	-0.69%	0.5%	0.10	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3	
North East Val.	9/18 +12/18	23.9	18	11.3	11.4	10.2	11.4	10.8	10.8	11.0	-0.45%	0.5%	0.06	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.3	11.3	11.4	11.4	
Omakau	3	3.6	0	1.6	1.54	1.7	1.5	1.6	1.6	1.8	1.33%	1.3%	0.02	1.7	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	
Outram	3 + 3	5.6	3.6	3	2.5	2.5	2.6	2.6	2.9	2.8	0.46%	0.5%	0.01	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	
Port Chalmers	7.5 +7.5	11.4	9	8	7.5	7.6	7.9	8.1	7.9	8.3	1.00%	1.0%	0.08	8.2	8.3	8.4	8.5	8.5	8.6	8.7	8.8	8.9	9.0	9.0	
Queensberry	3	3.3	0	0.5	0.6	0.8	1.4	1.6	1.9	1.7	28.34%		0.26	1.1	1.2	1.4	1.5	1.6	1.8	1.9	2.0	2.1	2.3	2.4	
Queenstown	10/20 +10/20	22	20	18.8	18.3	18.0	20.4	18.3	20.2	22.8	2.87%	2.9%	0.40	21.7	14.3	14.7	15.1	15.5	15.9	16.4	16.8	17.2	17.7	18.2	
Remarkables	1	1.2	0	0.8	0.8	0.8	0.8	0.7	0.8	0.8	-0.78%	0.0%	0.01	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Roxburgh	1.5 +1.5	3.6	1.8	2.4	2.9	1.9	1.7	2.3	2.5	2.5	0.06%	0.5%	0.01	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	
Smith St	15 + 15	18	18	18.2	19.0	16.0	18.1	18.1	16.5	16.9	-1.35%	1.0%	0.20	17.0	17.2	17.4	17.6	17.7	17.9	18.1	18.3	18.5	18.7	18.9	
South City	9/18 +9/18	18	18	13	13.0	11.8	13.6	14.3	15.4	15.7	4.00%	1.0%	0.20	15.7	15.8	16.0	16.2	16.4	16.6	16.7	16.9	17.1	17.3	17.5	
St Kilda	12/24 + 12/24	29	23	15	14.7	14.7	15.1	15.2	15.4	16.3	1.35%	1.4%	0.21	16.0	16.2	16.5	16.7	16.9	17.1	17.3	17.5	17.8	18.0	18.2	
Wanaka	12/24 +12/24	24	23	11.9	11.4	11.5	13.6	14.6	15.1	18.6	7.95%	7.9%	1.09	18.3	19.6	19.0	20.3	21.7	23.1	24.6	18.2	19.6	21.0	22.5	
Ward St	15 + 15	18	18	11.6	11.0	10.4	10.9	10.6	11.6	11.3	0.17%	0.2%	0.02	11.1	11.1	11.2	11.2	11.2	11.2	11.2	11.3	11.3	11.3	11.3	
Willowbank	15 + 15	18	18	14	12.2	12.1	13.7	13.7	12.8	12.7	-0.26%	0.5%	0.06	13.0	13.0	13.1	13.2	13.2	13.3	13.3	13.4	13.5	13.5	13.6	
Commonage	7.5/15+7.5/15	15	15									3.0%	0.24		8.0	8.2	8.5	8.7	9.0	9.2	9.5	9.8	10.0	10.3	
Cardrona		5																							
Jacks Point	7.5/10	10	0									8.0%	0.20	0.0	0.0	0.0	2.2	2.4	2.6	2.8	3.0	3.2	3.4	3.7	
Aubrey Rd	12/23 +12/23	23	23									6.0%	0.48							0.0	8.0	8.5	9.0	9.5	
Tarras																				0.0	0.0	0.0	0.0	0.0	
MG + ET (Merged 1/2hr data)		30.8	30.8			24.39	25.05	25.98	27.25	26.46	2.50%	3%	0.6	27.8	24.4	25.0	25.7	26.3	27.0	27.6	28.3	29.0	29.6	30.3	
Subtransmission																									
Upper Clutha Total																									
QT Sub TX		40		23.9	23.1	23.2	25.6	23.7	25.8	28.9					27.8	28.5	29.3	30.2	31	31.9	32.8	33.7	34.6	35.5	36
Arrowtown Ring	0.9 diversity			8.8	8.5	9.0	10.4	12.1	12.1	12.9					13.2	13.7	14.2	14.1	14.6	15.1	15.7	16.2	16.8	17.4	18.0

Table 5.6 – Zone Substation Historical and Predicted Demands

5.11.2 **Morven Ferry Substation**

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

The estimated project cost is \$1,000,000.

5.11.3 **Mosgiel Substation**

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

In the 2007 plan, it was proposed that the Mosgiel 33kV bus be operated solid which would have increased the firm load to 35.3MW. This proposal was a significant protection challenge and consultants who reviewed the proposal described it as “ambitious,” hence it has been rejected.

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

This is estimated to cost \$1.6 million.

The 11kV switchgear at Mosgiel is also scheduled for replacement in 2008/09 at an estimated cost of \$650,000.

5.11.4 **Tarras Substation**

The Queensberry substation had a 2006 peak load of 1.9 MVA and the area is still experiencing strong growth mainly due to irrigation load. There is no spare 66/11kV transformer available in the event of the Queensberry unit failing. The 2006 plan recommended that a new substation be established in Maori Point road to support the Queensberry substation and provide an alternative supply should the Queensberry transformer fail. During a review process it was decided to investigate the purchase of a mobile substation that could be used to replace the Queensberry transformer in the event of a failure and can also be used to as a replacement for other Aurora transformers. This project has been authorised and is underway at a cost of \$1.4 million. The provision of a new substation at Tarras is therefore not contemplated within the planning period.

5.11.5 Frankton Substation

Frankton substation has a 7.5/15 MVA and a 7.5/10 MVA transformer. The substation is expected to reach its firm load in 2010.

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

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

Augmentation of the substation will be required by 2011. This could be initially provided by a new substation at Jacks Point in 2011 (See section 5.11.9.) A new 12/24 MVA transformer may then be required by the winter of 2018. Augmentation before 2018 would be required if the Jacks Point substation does not proceed.

5.11.6 Queenstown Substation

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

5.11.7 Cromwell Substation

The Cromwell substation exceeded its firm capacity in the winter of 2007. A number of options are available. The preferred option is to ensure a mobile substation is available which would allow load to increase up to 12.5 MVA. The possibility of moving a transformer from East Taieri in 2011 to increase the capacity of this substation is currently being investigated.

5.11.8 Commonage Substation

A project to commission a new substation in the Commonage area on Queenstown Hill in 2009 consisting of two 15MVA transformers is underway. This substation will reduce the load on the Queenstown substation and improve the ability to offload HV feeders in the area. This project is estimated to cost \$5,000,000 including the HV feeder works.

5.11.9 Jack's Point Substation

Significant developments (2,700 lots) are under way in the Jack's Point area, which is off the Frankton to Kingston Road approximately 5 km from Frankton. This development will be initially supplied from Frankton feeder 703 up to a load of approximately 2 MVA. When this load limit is reached, it is intended to install a 33/11kV substation supplied from the 33 kV line to Wye Creek. The substation will be designed to eventually accommodate two 5/10MVA transformers. A site has been chosen and a 33kV cable has been installed to the site. Timing depends on the uptake of subdivision lots but is anticipated to be by 2011. The cost estimate is \$1,300,000.

5.12 HV Feeders

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

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

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

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

5.13 Distribution Substations

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

5.13.1 Distribution Substation Utilisation

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

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

Table 5.7 – Distribution Transformer Utilisation

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

5.14 Reliability and Risk Mitigation Projects

Reliability-initiated projects that will economically reduce the number or duration of consumer outages are proposed i.e. the installation of auto-reclosers and remote control facilities. Individual projects are not detailed in this plan as those currently being considered are small scale projects less than \$300,000 in value.

5.14.1 HV Feeder Performance

Set out in Figure 5.2 is data on outages per circuit plotted against circuit length⁵. All things being equal, feeders of similar length in similar physical environments would be expected to suffer similar numbers of faults. The worst performing feeders have been investigated and, where economic, projects to improve feeder reliability are initiated. Note that outages upstream of the feeder breaker are included but the length of the upstream feeders is not. Thus, all outages that a consumer experiences, including subtransmission and zone substation events, are shown in this graph.

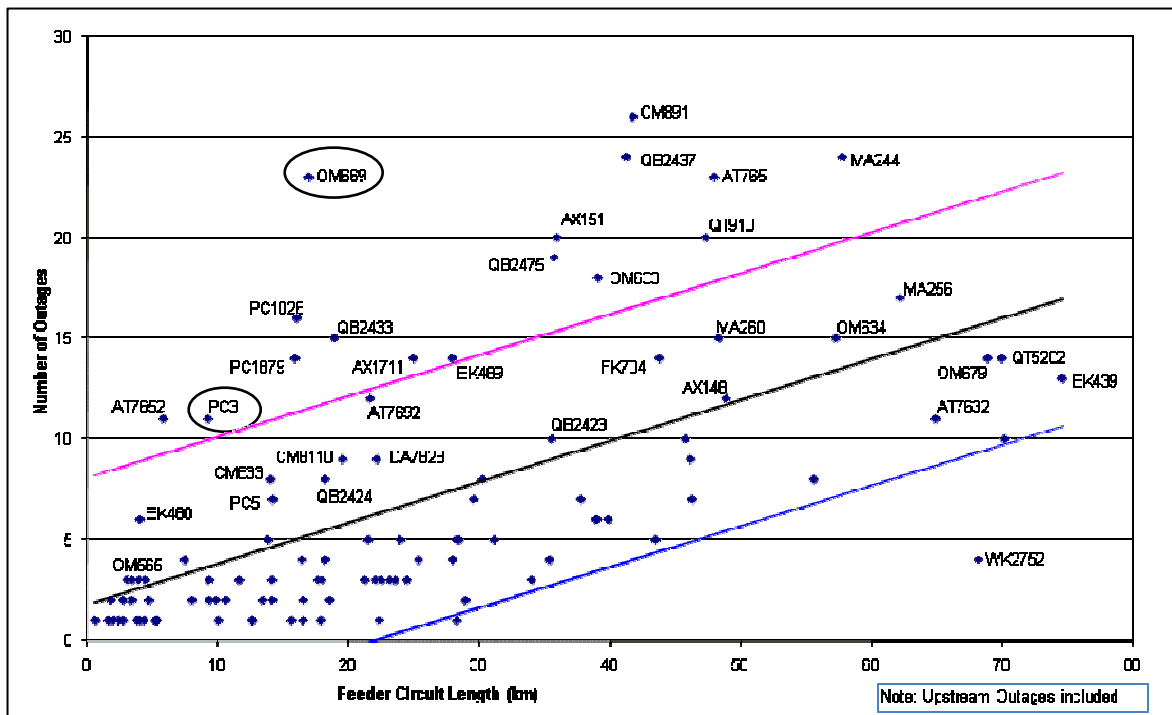


Figure 5.2 – HV Feeder Outages as a Function of Feeder Length (2007)

Another reliability indicator is the system customer outage minutes per HV feeder which is detailed in Figure 5.3. OM669 and PC3 in particular are being monitored closely as they performed badly in the previous year.

⁵ Figures for circuit lengths have been updated since the 2006 AMP to be based on the 'protective' zone of each circuit breaker.

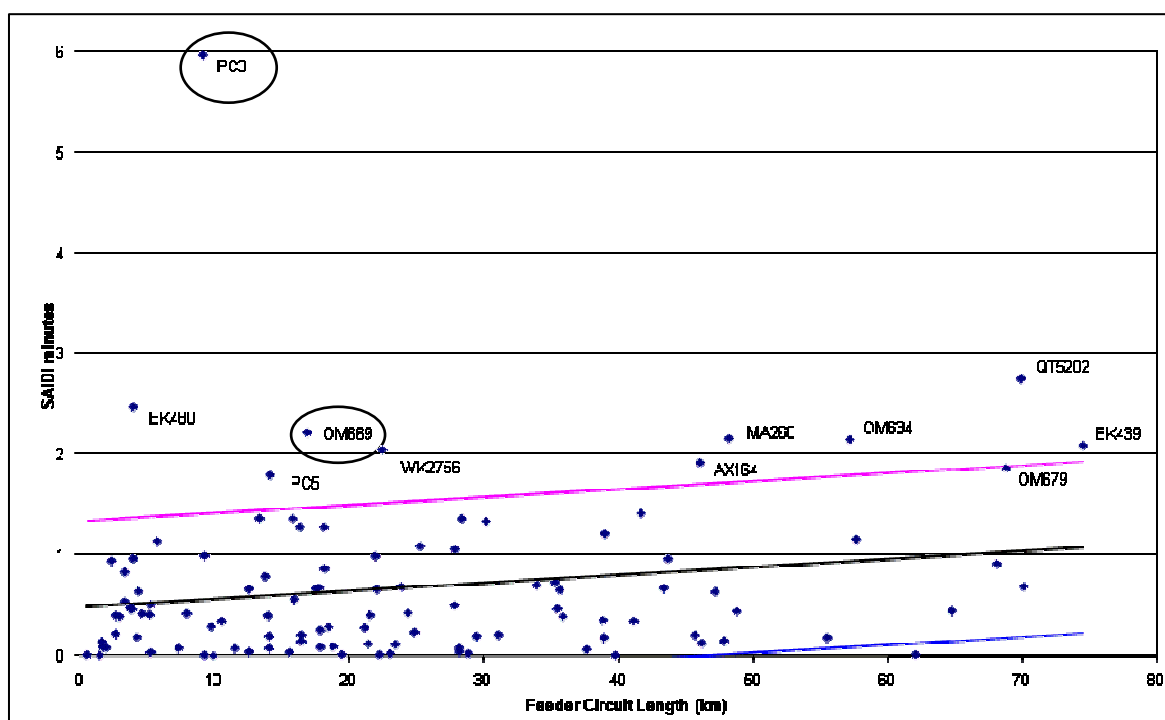


Figure 5.3 – HV Feeder Customer Outage Minutes by HV Feeder (2007)

5.15 Overhead to Underground Conversion Projects

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

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

Authority	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
DCC	1,620	1,620	1,640	1,660	1,680	1,700	1,720	1,740	1,750	1,770
CODC	290	290	290	300	310	320	330	340	350	360
QLDC	460	460	480	490	500	510	530	540	560	570

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

5.16 New Customer Connections

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

The expenditure in these categories is entirely customer driven and subject to regional economic activity. The budgeted annual expenditure is presented in Table 5.1 above. Whilst this forecast is shown as a constant \$8.2 million per year, we expect some slight variations from year to year. Whilst internal economic activity may reduce in the short term, that can be compensated by increased economic activity due to funding by international investors especially in the Queenstown and Wanaka areas.

6 Lifecycle Asset Management Planning for Maintenance and Renewal

6.1 Maintenance Planning Criteria and Assumptions

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

Maintenance work comprises two main elements:

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

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

- | | | |
|--------------------------------|-----|--------------------------------|
| • planned refurbishment | 56% | |
| • fault refurbishments | 21% | |
| • planned (pole) renewals | 13% | (individual pole replacements) |
| • routine inspection and tests | 8% | |
| • special inspections | 2% | |

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

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

6.2 Routine and Preventative Inspection and Maintenance

Around 8% of Aurora's maintenance expenditure is for periodic inspections, servicing and tests, to ensure that defects or emerging risks are identified and mitigated. Servicing can also involve minor component replacements (for example - seals, bushings etc), but does not involve any significant repairs.

DELTA has developed routine procedures for this type of work, specific to each asset type, which define the frequency of servicing/inspection and the scope of work that must be covered. They are based on a combination of manufacturers' recommendations, industry practice and *DELTA*'s own experience; which, in turn, is based on the incidence of faults and defects for each asset design, type, make or model, and factors such as its operating environment (salt-laden atmosphere, wind, etc).

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

For circuit breakers, intervals for minor and major services, and the type of work to be carried out, are defined for each type, make and model and the interval monitored against failure rates. These services vary from annual servicing costing in the order of a few hundred dollars per breaker, to major overhaul costing up to several thousand dollars occurring infrequently. Greater emphasis is being placed on in-service diagnostic testing as techniques for this become better developed. This can be a cost-effective means of identifying defects and items that are at risk of failure. It includes (for example) chemical analysis of transformer oil and use of thermographic cameras to identify "hot spots".

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

6.2.1 Subtransmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and solid (oil-impregnated paper) and XLPE types. Pressure alarms are installed on the former two and these are tested at six-monthly intervals and the outer sheath electrical integrity on most cables tested annually. Occasionally, leaks develop in these cables, usually at joints or where the cables have been stressed on installation. Faults are expensive to repair, being very labour intensive. The impregnated paper solid insulation type cables are virtually maintenance free but faults occasionally occur due to insulation flow on hill sections or if they have been damaged by third parties (for example - road openings etc). An above-ground visual inspection programme is in place, which involves inspecting the route of each cable for ground disturbance or ground movement, providing suspect areas for further detailed investigation.

Overhead Lines

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

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

Protection Pilots

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

6.2.2 Zone Substations

33kV Transformers and Tapchangers

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

Tests are carried out on winding and oil temperature alarms from source and Buchholz relay operation at 2.5-year intervals with the associated circuit breaker maintenance.

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

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

Buildings and Grounds

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

Corstorphine, South City and Ward Street substations have asbestos materials installed in some areas. Tests are carried out at 5-year intervals to monitor air-borne fibres.

Circuit Breakers, Isolators and Structures

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

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

Ripple Injection Plant

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

Miscellaneous

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

Earth connections for all equipment above ground level are inspected and maintained at 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 the SCADA screen and by printout. The work is carried out in conjunction with minor circuit breaker servicing work.

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

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

6.2.3 HV and LV Lines and Cables

At present, lines are inspected approximately every three years, and the procedures in the new Hazards from Trees Regulations that came into effect from 1 July 2005 are followed. A précis of these regulations is published on Aurora's website.

HV and LV Lines

A rolling inspection of approximately 600 km of overhead lines occurs each year (covering LV, HV, and combinations of both) to establish priorities for the maintenance programme.

HV and LV Cables

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

Earths

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

6.2.4 Distribution Substations

Substations

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

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

Buildings and Grounds

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

Switchgear

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

6.2.5 System Control

SCADA

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

UHF and VHF Systems

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

Miscellaneous

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

6.2.6 Expenditure Projections

It is expected that the routine and preventative inspection and costs to meet agreed service targets over the next 10 years will be generally in line with the figures shown in Table 6.1.

Financial Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Subtransmission	117	121	124	128	131	135	139	142	146	150
Zone substations	105	108	111	114	117	121	124	127	131	134
System control	18	18	19	19	20	20	21	22	22	23
HV and LV	1,038	1,066	1,095	1,125	1,156	1,188	1,221	1,254	1,289	1,325
Distribution substations	117	121	124	128	131	135	138	142	146	150
Total	1,395	1,434	1,473	1,514	1,555	1,599	1,643	1,687	1,734	1,782

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

6.3 Asset Renewal and Refurbishment Policies

6.3.1 Planned Renewal and Refurbishment

Around 70% of maintenance expenditure is for planned renewals and refurbishment of unserviceable assets. About half of this involves asset renewal or refurbishment programmes to a class or model of asset or component based on evidence of a "type failure" or design weakness.

These programmes of work are identified and planned before the beginning of a financial year. The remainder comprises a large number of what are typically minor component refurbishment (for example - individual insulators) many of which arise out of specific defects found within the year.

6.3.2 Fault Refurbishment

Fault refurbishments are carried out directly following an equipment failure, in order to restore service, and account for around 20% of maintenance expenditure. This work may or may not involve permanent refurbishment of the faulted equipment as the objective is to restore service as quickly as possible by the most economical method. If the fault involves major refurbishment work, it may be that the faulted unit is renewed by a serviceable unit; for example a spare transformer unit. The faulted unit can then be refurbished later, or a decision may be taken to dispose of it if refurbishment cannot be justified.

6.3.3 Overhead Line Repairs and Refurbishment

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

6.3.4 Circuit Breaker Renewal

Modelling has also been undertaken for programming circuit breaker renewals, based on data for individual circuit breaker types, make and model, together with an assessment of the expected economic service life of each circuit breaker and its current rating.

Servicing expenditure for circuit breakers is also produced by the same model. Individual circuit breaker servicing frequencies and their average costs per service enables the model to calculate the annual servicing cost based on the population of circuit breakers in each year.

6.3.5 Power Transformer and Distribution Transformer Renewals and Refurbishment

Similar modelling as has been used for circuit breakers is utilised for assessing renewal/refurbishment for transformers.

Where pro-active refurbishment is required, the analysis has been conducted based on the total number of units in service and an assessment of when and how many of the transformers may be removed from service for refurbishment each year. This analysis includes winding, core and internal connection repairs, oil refurbishment, painting and radiator renewal.

6.4 Maintenance and Refurbishment Programmes

6.4.1 Subtransmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and solid types. Leaks occasionally develop on the gas and oil filled cables, usually at joints or where the cables have been stressed on installation. Faults refurbishment is expensive, being very labour intensive. The 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 (for example - road openings, etc).

Overhead Lines

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

Protection Pilots

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

6.4.2 Zone Substations

33kV Transformers and Tapchangers

Although the age profile is getting high, these transformers have not been heavily loaded during their life and only one transformer renewal is considered necessary within the planning period (for the Berwick transformer due to age, inadequate tapping range and a non-standard vector group).

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

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

Buildings and Grounds

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

Circuit Breakers, Isolators and Structures

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

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

Ripple Injection Plant

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

At present no 33kV injection equipment in the Central network area has been identified as requiring renewal or refurbishment.

There are approximately 65 distribution substations in the Central Otago network which had pilot wire control circuits installed between 1970 and 1988. These have been suffering from decreased reliability, and it has been standard practice after failure of these circuits for the retailer to renew the pilot wire relay on the consumer's switchboard with a modern ripple receiver.

Miscellaneous

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

6.4.3 HV and LV Lines and Cables

HV and LV Lines

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

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

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

HV and LV Cables

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

Earths

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

6.4.4 Distribution Substations

Transformers

In the Central Otago area, some 16 pedestal-mounted transformers are to be renewed. They have been identified as being a latent safety concern. Presently, 4-5 per year are planned to be renewed with ground-mounted substations.

Substations

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

Buildings and Grounds

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

Switchgear

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

6.4.5 System Control

SCADA

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

UHF and VHF Systems

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

Miscellaneous

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

6.4.6 Expenditure Projections

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

Financial Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Subtransmission	1,062	1,090	1,119	1,151	1,181	1,214	1,248	1,282	1,317	1,353
Zone substations	948	974	1,000	1,028	1,057	1,085	1,115	1,146	1,177	1,210
System control	158	163	167	172	176	182	187	193	198	203
HV and LV	9,338	9,595	9,860	10,130	10,409	10,695	10,989	11,291	11,602	11,920
Distribution substations	1,058	1,088	1,118	1,148	1,179	1,212	1,245	1,280	1,316	1,352
Total	12,564	12,910	13,264	13,629	14,004	14,388	14,784	15,192	15,610	16,038

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

6.5 Capital Replacement Projects

Replacement of equipment is scheduled when the annual cost to own, operate, and maintain existing equipment plus the average annual cost of consequential failure exceeds the annual cost to own, operate, and maintain new equipment i.e. a cost-benefit analysis. Potential projects exceeding \$300,000 in cost are detailed in this section.

6.5.1 33kV Gas Cables

Five Dunedin zone substations are supplied by gas insulated 33kV cables detailed in Table 6.3. These cables have been prone to gas leaks and the failure rate has increased significantly since mid 2003. For six months in 2004-05 the failure rate reached 20 failures per 100 km per year which was unacceptably high. Since then the failure rate has reduced and remains low. No robust explanation for this random behaviour has been found.

Cable	Year Installed	Route Length (km)		Notes
		Actual	Optimised	
HWB–Neville Street	1961	6.82	1.7	Has a tie to Ward Street
HWB–Ward Street	1967	4.21	2.35	Has a tie to Neville Street
HWB–Willowbank	1963	3.95		
HWB–Smith Street	1959	3.2		
South Dn–Andersons Bay	1961	2.7		

Table 6.3 – Schedule of 33kV Gas Cables

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

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

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

6.5.2 Ward Street Substation Upgrade

The transformers and 6.6kV switchgear at Ward Street were installed in 1938 (70 years old). Additional switchgear was added in 1943 and 1951. Subject to confirmation by economic analysis, it is proposed that the entire substation be rebuilt during the summer of 2009/10. The project cost estimate is \$3.0 million.

6.5.3 Zone Substation 6.6/11kV Switchgear Replacement

The following zone substation 6.6/11kV switchgear is older than their ODV life (40 years). This, in itself, is not a reason for replacement – condition and perceived reliability are the relevant factors considered. The switchgear tentatively scheduled for replacement is listed in Table 6.4

Substation	Manufacture Year	Status	Number CBs	Year*	Cost (\$000)
Ward Street	1938	Planned	14	2010/11	Note 1
Roxburgh	1950	Planned	1	2008/09	30
Remarkables	1950	Monitor	1		
Frankton	1950	Planned	8	2009/11	Note 2
Neville Street	1953	Monitor	14		
Mosgiel	1954	Planned	10	2008/09	650
Halfway Bush	1956	Monitor	16	-	
Green Island	1957	Monitor	15	-	
Smith Street	1958	Monitor	15	-	
Earnsclough	1960	Monitor	1	-	
Dalefield	1960	Monitor	1		
Outram	1963	Monitor	8		

Table 6.4 – Zone Substation 6.6/11kV Circuit Breaker Replacement Schedule

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

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

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

6.5.4 Distribution Circuit Breaker Replacement

A number of distribution substations have oil circuit breakers installed that are in excess of 50 years old, obsolete and becoming expensive to maintain. At present it is not economic to replace these circuit breakers but maintenance costs and reliability will continue to be monitored. The applicable sites are listed in Table 6.5.

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

Table 6.5 – Distribution Substation HV Circuit Breaker Replacement Schedule

6.5.5 Replacement of Ripple Injection Equipment

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

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

Low frequency 33kV injection is preferred because:

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

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

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

6.5.6 Dunedin SCADA RTU Replacements

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

7 Risk Policies, Assessment, and Mitigation

7.1 Methods, Details and Conclusions of Risk Analysis

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

7.1.1 Risk Management

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

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

Generic Risk Area	Sub-Category	Policy Reference
	Fraud	<ul style="list-style-type: none"> ▪ Fraud and Other Similar Irregularities policy ▪ Protected Disclosures policy ▪ Delegations Policy
Information systems	Financial systems	<ul style="list-style-type: none"> • Delegations Authorities Policy
	Archives	<ul style="list-style-type: none"> • Company Filing Policy
	Filing system	
Legal compliance	Health and Safety in Employment Act	<ul style="list-style-type: none"> ▪ Health and Safety policy
	Electricity Act and associated Regulations	<ul style="list-style-type: none"> ▪ Network policy
	Resource Management Act	<ul style="list-style-type: none"> ▪ Environmental policy
	Human Rights Act	<ul style="list-style-type: none"> ▪ Human Rights in Employment policy
	Local Government Official Information and Meetings Act	<ul style="list-style-type: none"> ▪ Handling of Complaints policy
	Ombudsmen Act	<ul style="list-style-type: none"> ▪ Handling of Complaints policy
	Privacy Act	<ul style="list-style-type: none"> ▪ Security of Personal Information policy
	Protected Disclosures Act	<ul style="list-style-type: none"> ▪ Protected Disclosures policy

To complement this policy, external audits are undertaken to ensure a holistic view is obtained. External reviews include:

- August 2000. Assessment of network risks in the Central Otago region focussing on the 33kV system and zone substations.
- November 2001. Assessment of network risks in the Dunedin region focussing on the 33kV system and zone substations.
- November 2003. This review focussed on environmental aspects of risk assessment. I.e. risks from the environment within which the distribution of electricity occurs, rather than from within the technical infrastructure of the electricity transmission system.
- July 2004. This review focused on fire risks at zone substations and resulted in minor works being authorised to avoid fire migration from one piece of equipment to another.
- May 2005. All ground-mounted transformers were assessed for risk of being hit by a vehicle and resulting in oil leak into a water way. A small number of transformers have been identified as high risk and mitigation options are currently being considered. One transformer site has had additional traffic protection measures installed.
- March 2007. Analysis and review of circuit breaker monitoring and maintenance procedures.
- June 2008. Analysis and review of pole inspection records, monitoring and data capture procedures.

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

During the flash floods in Dunedin in early February 2005, five of the twenty underground distribution substations were flooded. A review has been completed and remedial works to make the vaults more watertight is underway. The risk of not obtaining adequate competent human resources is now believed to be an industry-wide risk. In reviewing the progress of capital works in particular over the last year, the ability of the supply industry to meet what have been historically reasonable deadlines has declined. Consulting staff are not as available as they have been in the past, and equipment procurement, particularly power transformers, requires longer lead times than even 18 months ago.

7.1.2 Injection Performance

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

	n-1 Transpower Capacity MVA	Embedded Generation MW	n-1 Security
Halfway Bush	144	44	No ⁶
South Dunedin	100	-	Yes
Clyde	60	17	Yes
Frankton	54	2	Yes
Cromwell	27	4	Yes

Table 7.1 – Injection Security

7.1.3 Network Capacity (i.e. Adequacy of Service)

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

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

Reliability is a function of:

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

While, ultimately, it is customers' requirements and financial commitments which drive work which might alter system reliability, expenditure is presently planned to achieve the supply reliability targets set out in Section 4.2.1.

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

⁶Refer to Section 5.9.5

7.1.5 **Safety**

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

The Health and Safety in Employment Act is a key item of safety legislation impacting on Aurora. While not overriding safety requirements found in Electricity Acts and Regulations, the Act has far reaching impact, requiring all hazards associated with assets to be identified, assessed, and controlled if found to be significant. This is achieved by duties set on all parties associated with design, construction, maintenance and operation of Aurora assets.

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

All operation and maintenance work performed on Aurora network assets must be performed in accordance with "Safety Rules, Electricity Industry" which is a set of safety rules for the New Zealand Electricity Generation Transmission and Distribution Industry and the "General Safety Handbook, Electricity Industry". These two publications are industry-accepted standards and provide a means of complying with the safety requirements of the Health and Safety in Employment Act and the Electricity Act and Electricity Regulations and subsequent amendments.

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

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

7.1.6 **Environmental Responsibility**

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

The Resource Management Act is the major legal driver. The provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise and the duty to avoid, remedy or mitigate any adverse effect on the environment are of particular relevance. One noise complaint was investigated in mid 2002 and was found to be without foundation.

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

The main environmental risk from Aurora operations is the accidental discharge of insulating oil into waterways. Oil spill kits are provided at all zone substations and contractors are required to carry oil spill kits in vehicles used to transport oil filled equipment.

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

7.2 Details of Emergency Response and Contingency Plans

7.2.1 General

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

7.2.2 Civil Defence

DELTA has a comprehensive plan for response to emergency situations and to liaise with local Civil Defence organisations for the effective use and co-ordination of resources within its electrical supply area in those circumstances. The details are in documents QP2001 Civil Defence and QP2002 Emergency Preparedness Plan.

7.2.3 Routine Emergency Response

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

7.2.4 Contingency Plans

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

8 Performance Measurement, Evaluation and Improvement

8.1 Review of Network Service Level Performance

8.1.1 Reliability

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

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

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

System performance is categorised to eliminate causes outside 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 to identify areas that may produce cost effective minimising of disruption from those events.

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

The secondary performance measure is “unplanned by line owner SAIFI” as described in Section 4.1. Whilst this was only nominally over target, investigations into the cause of this are on-going and remedial measures are currently being considered. As a result of this, tree trimming is to be continue to be targeted at selected problem feeders

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

8.1.2 Faults per 100km HV Circuit

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

8.1.3 Low Voltage Complaints

Seventeen valid voltage complaints were received for the year 1 April 2007 to 31 March 2008. This is an increase of 2 from the previous year.

8.1.4 Environmental Performance

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

8.2 Review of Financial Performance

8.2.1 Operating and Maintenance Expenditure

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

- overhead line inspections have been completed as scheduled;
- thermal imaging of all zone substation equipment and major distribution assets was carried out - repairs as necessary have been completed.

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

Category	2007/08 Actual	2007/08 Budget	Variance	
	\$000	\$000	\$000	%
Subtransmission	1,640	1,114	526	47%
Zone substations	1,751	1,296	455	35%
System control	176	184	-8	-4%
HV and LV lines and cables	9,947	9,748	199	2%
Distribution substations	1,321	1,244	77	6%
Total	14,835	13,586	1,249	9%

Table 8.2 – Operating and Maintenance Expenditure Budget Compared to Actual

The causes for the variances are:

- the primary causes for subtransmission system unfavourable variance were a severe wind storm on 10 and 11 August 2007 which caused loss of supply to Wanaka for ten hours, higher than expected fault incidence of 33 kV cable faults in Dunedin and increased tree trimming to improve system security – especially in the Queenstown area.
- the zone substation unfavourable variance was caused by a succession of individual unrelated small faults, such as tapchanger repairs as well as programmed inspection and maintenance for items such as earth grids.
- HV and LV lines and cables was over budget due to increased tree trimming and fault repair work – in particular a storm in Dunedin in October 2007 caused considerable damage in a one hour period as well as damage incurred during the storm in the Central region mentioned above.

8.2.2 Capital Expenditure

A comparison of Aurora's capital expenditure budget is shown below:

Category	2007/08 Actual (\$000)	2007/08 Budget (\$000)	Variance (\$000)	
New connections	8,850	8,200	650	8%
Localised growth	2,800	3,100	-300	-10%
System development	580	700	-120	17%
Undergrounding projects	1,885	2,832	-947	-33%
Upgrade Berwick zone substation	530	530	0	-0%
Mobile substation (66kV/33kV/11kV)	200	1,400	-1,200	-86%
Cardrona generator	705	705	0	0%
Queenstown and Frankton cables	1,372	1,267	105	8%
Dunedin subtransmission reinforcement	0	450	450	100%
Cardrona designation	55	50	5	10%
Total	17,177	19,434	-2,257	-12%

Table 8.3 – Comparison of Actual Capital Expenditure with Plan

Overall, capital expenditure was behind budget provisions, mainly due to delays to undergrounding projects and to re-programming of the mobile substation due to longer than originally envisaged material supply times.

The causes for the variances are:

- New connections, which is consumer initiated work, was higher than budget due to demand by developers and new consumers.
- Localised growth is a combination of planned works required to meet growth and works required for the correction of voltage complaints. This was below budget primarily due to fewer voltage complaints requiring new substations to be installed
- The completion of the Queenstown and Frankton cable projects was required to maintain subtransmission security. These projects required significant resources which were consequently not available for other projects such as undergrounding.
- Undergrounding was behind budget due to late Local Body approval of projects and the deliberate diversion of resources to service customer driven and load growth projects.

As a result the "shortfall" in 2007/08 has been carried forward as us illustrated below:

Item	Value (\$000)	Status
Mobile substation	1,200	Equipment ordered.
Dunedin subtransmission	450	Economic evaluation of Kaikorai cables replacement is underway.
Undergrounding projects	950	Projects designed and cable ordered.

Table 8.4 Capital Funds to be carried forward

8.3 Gap Analysis and Identification of Improvement Initiatives

Both planned and unplanned maintenance activities are analysed to monitor performance trends and to evolve both maintenance practices and replacement policies. No changes to current practices have been identified in the last year. However some policies are to be externally reviewed in the 2008/09 year to confirm that they still meet best practice.

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

Recently identified improvements have included:

- replacing the Mosgiel 11 kV switchgear due to reliability concerns.(planned)
- Berwick zone substation upgrade (substantially complete as at 31 March);
- voltage regulators to be installed at the Pisa Moorings (approved and underway);
- reclosers to improve reliability at the Ettrick and Poolburn areas (completed);
- Scada improvements to the Central network (ongoing);
- data quality improvements to the GIS records when economic to do so.

The use of RCC Ground Fault Neutralisers has been considered and is not yet considered to be economic.

Glossary of Terms

CPD	Congestion Period Demand
CAIDI	Consumer Average Interruption Duration Index
CODC	Central Otago District Council
DCC	Dunedin City Council
DGA	Dissolved Gas Analysis
DRC	Depreciated Replacement Cost
DSM	Demand side management
GXP	Grid Exit Point
HWB	Halfway Bush
Hz	Hertz
IEDs	Intelligent Electronic Devices
MDIs	Maximum Demand Indicators
MVA	Megavolt amps
MW	Megawatts (one million watts)
pf	power factor
QLDC	Queenstown-Lakes District Council
RC	Replacement cost
SAIDI	System Average Interruption Duration Index (minutes) (= sum of number of interrupted customers x interruption duration) / total number of customers
SAIFI	System Average Interruption Frequency Index

Appendix A – Major Capital Projects

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

Year ending March	Project Name	Status	Value \$(000)	Section #
2008	Berwick transformer	Complete	\$530	6.5.2
2008	Queenstown cables	Substantially complete	\$822	5.10.1
2008	Frankton 33 kV cables	Substantially complete	\$250	5.10.1
2009	Cardrona generation	Underway	\$500	5.10.2
2009	Mosgiel switchgear	Proposed	\$650	5.11.3
2009	Mobile substation	Underway	\$1,400	5.11.4
2010	Commonage substation	Underway	\$5,000	5.11.8
2010	East Taieri transformers	Proposed	\$1,600	5.11.3
2011	Wanaka to Hawea line	Proposed	\$1,000	5.10.3
2011	Frankton switchgear	Proposed	\$1,000	5.11.5
2010	Ward Street switchgear	Proposed	\$3,000	6.5.3
2012	Morven Ferry substation	Proposed	\$1,000	5.11.2
2011	Jack's Point substation	Proposed	\$1,300	5.11.9
2011	Dunedin ripple injection	On hold	\$1,450	6.5.6

Appendix B – Service Level Targets

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

SAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIDI
Actual	1999/00	18.9	175.7	194.6	-	13.4	13.4	208.0
	2000/01	16.7	62.4	79.1	-	3.3	3.3	82.4
	2001/02	13.8	61.5	75.3	-	13.4	13.4	88.7
	2002/03	20.5	68.6	89.1	-	12.1	12.1	101.2
	2003/04	16.3	80.0	96.3	-	1.0	1.0	97.3
	2004/05	7.3	73.2	80.5	-	-	-	80.5
	2005/06	11.7	70.8	82.5	-	14.0	14.0	96.5
	2006/07	13.2	83.5	96.7	-	4.7	4.7	101.4
	2007/08	13.3	116.0	129.3	-	11.0	11.0	140.3
Target	2008/09	15.0	73.0	88.0	-	-	-	88.0
	2009/10	15.0	72.0	87.0	-	-	-	87.0
	2010/11	15.0	71.0	86.0	-	-	-	86.0
	2011/12	14.0	71.0	85.0	-	-	-	85.0
	2012/13	14.0	70.0	84.0	-	-	-	84.0
	2013/14	14.0	69.0	83.0	-	-	-	83.0
	2014/15	14.0	68.0	82.0	-	-	-	82.0
	2015/16	13.0	68.0	81.0	-	-	-	81.0
	2016/17	13.0	67.0	80.0	-	-	-	80.0
	2017/18	13.0	66.0	79.0	-	-	-	79.0

SAIFI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall SAIFI
Actual	1999/00	0.12	1.62	1.74	-	0.45	0.45	2.19
	2000/01	0.11	1.19	1.30	-	0.11	0.11	1.41
	2001/02	0.17	1.39	1.56	-	0.23	0.23	1.79
	2002/03	0.15	1.36	1.51	-	0.57	0.57	2.08
	2003/04	0.14	1.47	1.61	-	0.11	0.11	1.72
	2004/05	0.07	1.39	1.46	-	-	-	1.46
	2005/06	0.09	1.40	1.49	-	0.23	0.23	1.72
	2006/07	0.10	1.59	1.69	-	0.13	0.13	1.82
	2007/08	0.10	1.37	1.47	-	0.35	0.35	1.82
Target	2008/09	0.13	1.33	1.46	-	-	-	1.46
	2009/10	0.13	1.31	1.44	-	-	-	1.44
	2010/11	0.13	1.29	1.42	-	-	-	1.42
	2011/12	0.12	1.27	1.39	-	-	-	1.39
	2012/13	0.12	1.26	1.38	-	-	-	1.38
	2013/14	0.12	1.25	1.37	-	-	-	1.37
	2014/15	0.12	1.24	1.36	-	-	-	1.36
	2015/16	0.11	1.24	1.35	-	-	-	1.35
	2016/17	0.11	1.22	1.33	-	-	-	1.33
	2017/18	0.11	1.20	1.31	-	-	-	1.31

CAIDI		Network Planned	Network Unplanned	Network Total	Transpower Planned	Transpower Unplanned	Transpower Total	Overall CAIDI
Actual	1999/00	159.9	108.3	111.8	-	29.6	29.8	95.0
	2000/01	158.6	52.6	60.8	-	29.2	30.0	58.4
	2001/02	81.7	42.2	48.3	-	59.0	58.3	49.6
	2002/03	134.9	50.6	59.0	-	21.3	21.2	48.7
	2003/04	119.9	54.5	59.8	-	8.8	9.1	56.6
	2004/05	100.2	52.8	55.1	-	-	-	55.1
	2005/06	135.7	50.5	55.4	-	60.0	60.9	56.1
	2006/07	127.0	52.6	57.2	-	35.6	36.2	55.7
	2007/08	129.5	84.6	88.0	-	31.4	31.4	77.1
Target	2008/09	120.0	55.0	60.0	-	-	-	60.0
	2009/10	120.0	55.0	60.0	-	-	-	60.0
	2010/11	120.0	55.0	60.0	-	-	-	60.0
	2011/12	120.0	55.0	60.0	-	-	-	60.0
	2012/13	120.0	55.0	60.0	-	-	-	60.0
	2013/14	120.0	55.0	60.0	-	-	-	60.0
	2014/15	120.0	55.0	60.0	-	-	-	60.0
	2015/16	120.0	55.0	60.0	-	-	-	60.0
	2016/17	120.0	55.0	60.0	-	-	-	60.0
	2017/18	120.0	55.0	60.0	-	-	-	60.0

Appendix C – Compliance Matrix

Revised Information Disclosure Requirements April 2006

	Requirement	AMP Location
4.5.1	Summary of the Asset Management Plan	1
4.5.2	Background and Objectives <ul style="list-style-type: none"> (a) Purpose of the plan. (b) Interaction of objectives with other corporate goals, business planning processes and plans. (c) Period to which the plan relates and date approved by board of directors. (d) Stakeholder interests. (e) Accountabilities and responsibilities for asset management. (f) Details of asset management systems and processes including asset management systems/software and information flows. 	2.1 2.2 2.2 / 2.3 2.4 2.4 2.5 2.6
4.5.3	Assets Covered <ul style="list-style-type: none"> (a) High level description of the distribution area. (b) Description of network configuration. (c) Description of network assets by category including age profiles and condition assessment. (d) Justification for the assets. 	3.1 3.2 3.5-3.8 3.9
4.5.4	Service Levels <ul style="list-style-type: none"> (a) Consumer oriented performance targets. (b) Other targets, e.g. – asset performance, asset efficiency and effectiveness, the efficiency of the lines business activity. (c) Justification for target levels of service based on consumer, legislative, stakeholder and other considerations. 	4.1 4.2 4.2
4.5.5	Network Development Planning <ul style="list-style-type: none"> (a) Description of the planning criteria and assumptions. (b) Description of the prioritisation methodology adopted for development projects. (c) Details of demand forecasts, the basis on which they are derived and the specific network locations where constraints are expected due to forecast load increases. (d) Distributed generation policy. (e) Non-network solution policy. (f) Analysis of network development options available and details of the decisions made to satisfy and meet target levels of service. (g) Description and identification of the network development programme and actions to be taken, including associated expenditure. 	5.4 / 5.8 5.5 / 5.7 5.1 / 5.6 5.9 5.2 5.3 5.1 / 5.10 / 5.14 / 5.15 5.1 / 5.10 – 5.16

	Requirement	AMP Location
4.5.6	Lifecycle Asset Management Planning (Maintenance and Renewal) <ul style="list-style-type: none"> (a) Description of maintenance planning criteria and assumptions. (b) Description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including expenditure projections. (c) Description of asset renewal and refurbishment policies. (d) Description and identification of renewal or refurbishment programmes or actions to be taken for each asset category, including associated expenditure projections. (e) Asset replacement and renewal expenditure. 	6.1 6.2 6.3 6.3 6.4 6.5
4.5.7	Risk Management <ul style="list-style-type: none"> (a) Methods, details and conclusions of risk analysis. (b) Details of emergency response and contingency plans. 	7.1 7.2
4.5.8	Evaluation of Performance <ul style="list-style-type: none"> (a) Review of progress against plan, both physical and financial. (b) Evaluation and comparison of actual performance against targeted performance objectives. (c) A gap analysis and identification of improvement initiatives. 	8.1 / 8.2 8.1 / 5.14 / 4.1/ 8.3