



AURORA ENERGY LTD

Asset Management Plan Number 14

April 2007 – March 2017

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 fourteenth network Asset Management Plan for the distribution networks owned by Aurora Energy Ltd and covers the 10 year period from 1 April 2007. It documents existing and projected network asset conditions and the likely or intended asset management programmes, based on the present understanding of customer requirements. It is not an approved programme for specific work; rather the programmes and projects are indicative. In some cases plans will be subject to user discussion and/or funding, while in all cases they are subject to financial approvals.

D I S C L A I M E R

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

1 Summary

1.1 Purpose

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

1.2 Background and Objectives

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

1.3 Assets Covered

The network assets consist of two geographically separate networks. The larger network is the electricity network which supplies 52,373 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 25,925 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.

| 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 90 minutes without supply per customer per year. (SAIDI) |
| Response Time - Dunedin Network Area Restore supply following general network failure. | Within 4 hours of notification. |
| Response Time - Central Network Area* Restore supply following general network failure. | Within 4 hours 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. Given the market survey response detailed in section 4.2.2, that consumers do not want to pay more for improved reliability, Aurora believes that maintaining the target of 90 SAIDI minutes is appropriate.

1.5 Network Development Plans

New capital works are driven by demand growth by existing consumers, 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:

| | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 17/18 |
|-------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| Total | 17,050 | 17,710 | 18,210 | 18,160 | 19,040 | 19,470 | 19,930 | 20,400 | 20,740 | 20,280 |

Table 1.3 Capital Expenditure

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

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

evolve. No significant change in maintenance policies is planned. The maintenance expenditure from Table 6.1 and Table 6.2 are summarised below in Table 1.4.

| Financial Year | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 |
|---|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| Inspection (Table 6.1) | 1,294 | 1,333 | 1,386 | 1,414 | 1,456 | 1,500 | 1,545 | 1,591 | 1,639 | 1,688 |
| Maintenance and Refurbishment (Table 6.2) | 11,646 | 11,995 | 12,475 | 12,724 | 13,106 | 13,499 | 13,904 | 14,321 | 14,751 | 15,193 |
| Total Maintenance Expenditure | 12,940 | 13,328 | 13,861 | 14,138 | 14,562 | 14,999 | 15,449 | 15,912 | 16,390 | 16,882 |

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 2006.

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.

¹ SAIDI = system average interruption duration index minutes

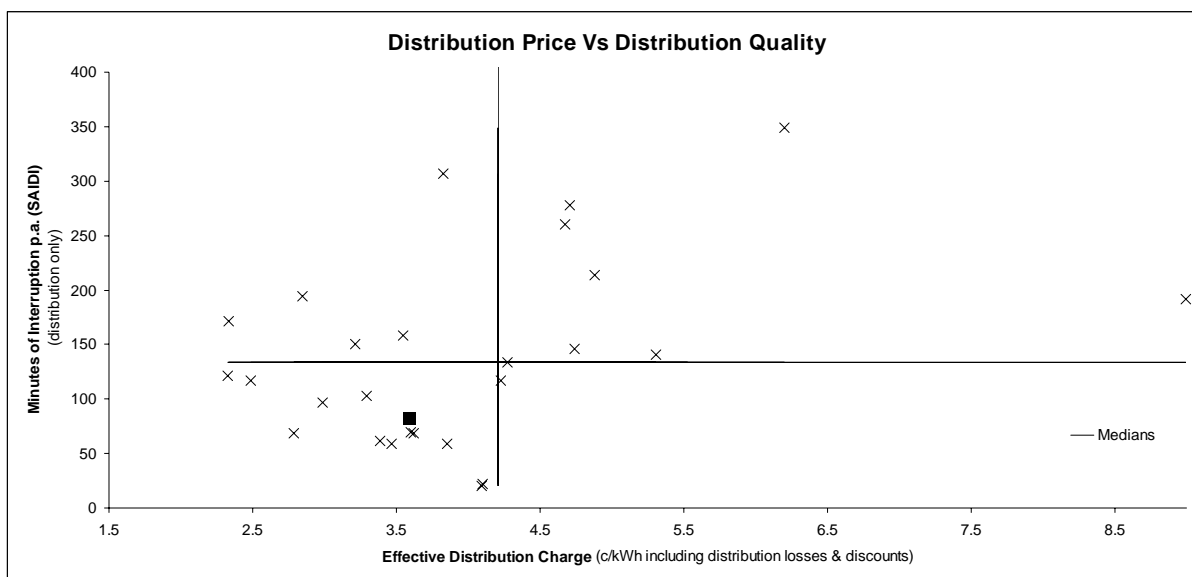


Figure 1.1 – Price-Quality Matrix

1.9 Stakeholder Consultation

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

For some years, Aurora has actively sought comment on its Asset Management Plan, including through newspaper advertisements and direct approaches. There has been one instance of feedback on the 2006 Asset Management Plan and this has been taken into account in the preparation of this document. Prior to this no comment had been received in response, other than from the Commerce Commission and its agents.

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 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 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.

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 2.2 overleaf.

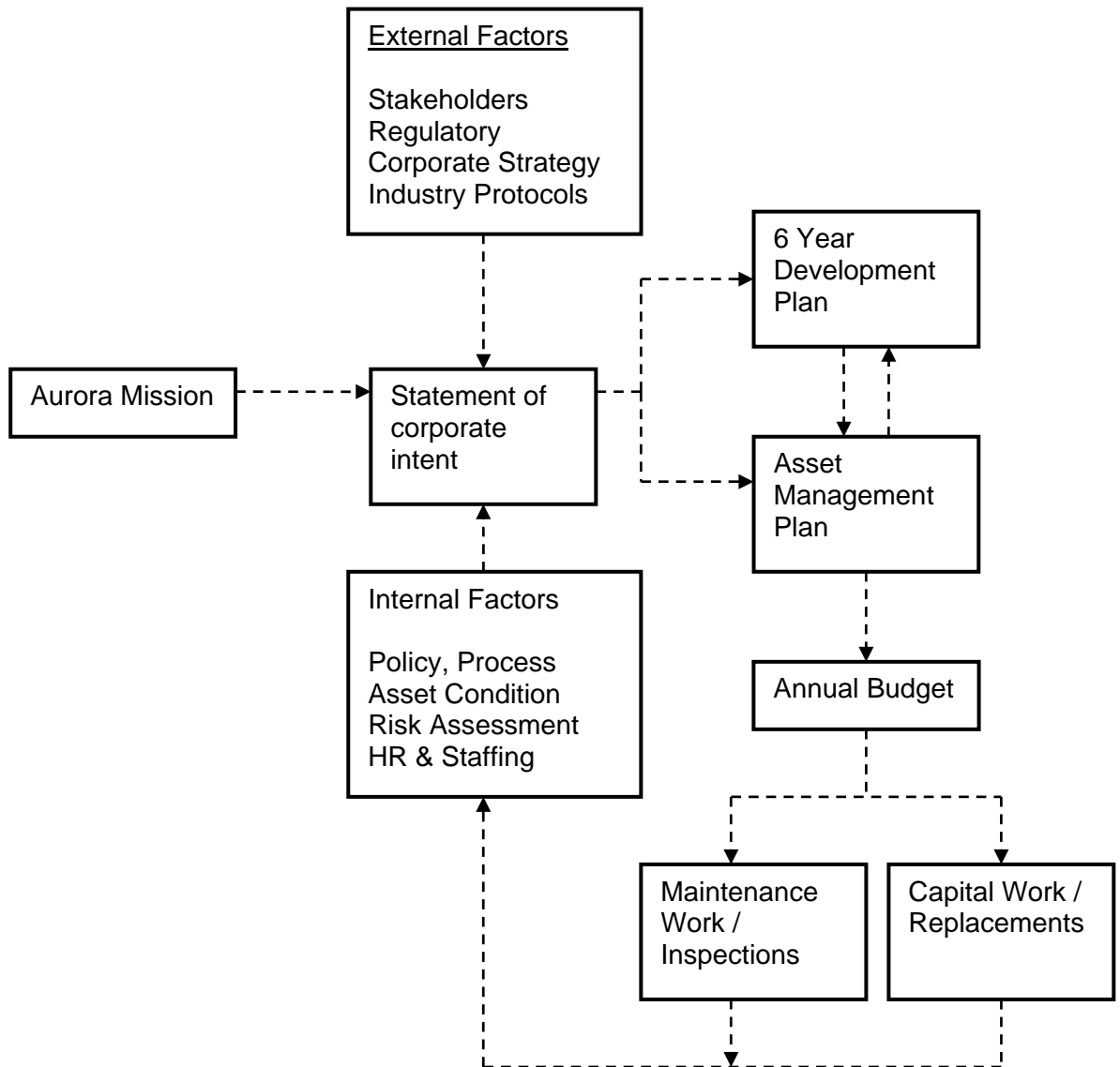
Aurora's Strategic Plan sets out the vision of the company and the key objectives that must be achieved if that vision is to be realised. The plan takes into account aspects such as regulatory, customer, staff and shareholder constraints and expectations and defines and shapes the AMP.

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

This Asset Management Plan covers the period from 1 April 2007 to 31 March 2017 and represents an evolution of the production of annual Asset Management Plans published for the Dunedin network since 1993.

The Board approved this (2007 – 2017) Asset Management Plan on 29 August 2007.

Figure 2.2 - Interaction between other business processes and plans



2.3 Period to Which Plan Relates

This plan relates to the 2007-2017 period.

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

2.4 Stakeholder Interests

2.4.1 Stakeholders

Stakeholders are those parties with a direct interest in Aurora's network asset management policies and practices. The 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 |
| Land Owners with network facilities on their land | Safety Easement conditions Access for maintenance/repair Compensation for significant interference |
| Property Developers | New-connection policies Timely network expansion |
| Shareholder | Adequate, stable and secure return on investment Good corporate citizenship |
| Territorial Authority | Minimising of environmental impacts (RMA) Local economic development Control of assets in road reserve Conversion of overhead to under-ground |
| Transit NZ | 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 (for example - by undertaking under-grounding projects in partnership with local authorities).
- 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 of 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. Some parties have forecasted that electricity supply to certain consumers will then cease, or continue only under much higher charges.

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

2.5 Accountabilities and Responsibilities

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

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

Figure 2.5 overleaf details the accountabilities and responsibilities for asset management within the Aurora / *DELTA* contract.

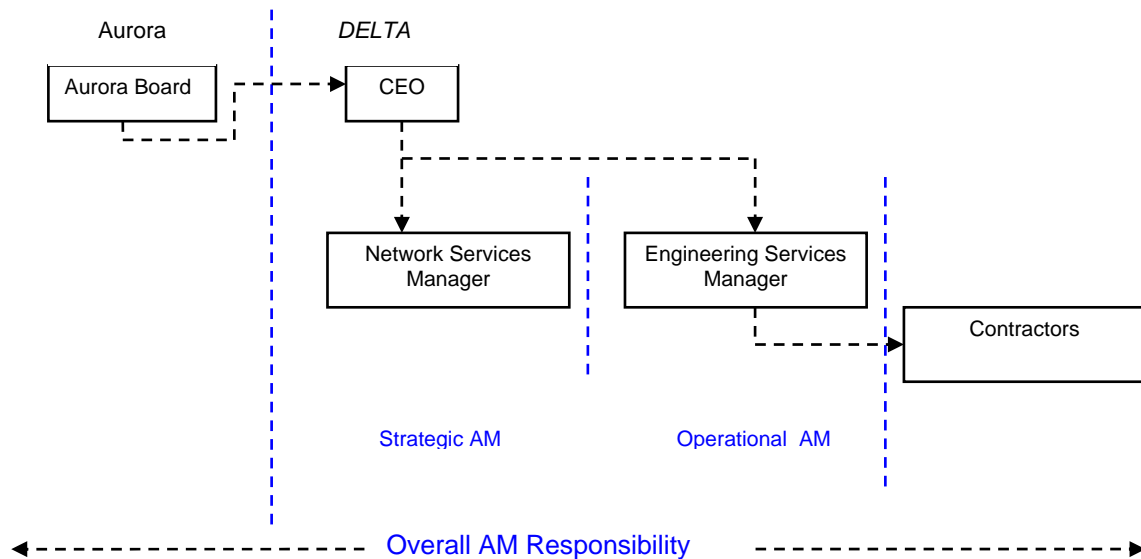


Figure 2.5: Asset Management accountabilities and responsibilities

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

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

| Staff Level | Delegated Financial Authority Budgeted Capex |
|---|---|
| Aurora Company Secretary | \$250,000 |
| <i>DELTA</i> CEO | \$250,000 |
| <i>DELTA</i> Engineering Services Manager | \$100,000 |

Table 2.5 – Delegated Financial Authority Levels

2.6 Details of Asset Management Systems and Processes

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

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

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, which are described in detail in Section 3, consist of two geographically separate networks in Dunedin and Central Otago as shown in Figure 3.1 below. The larger network is the electricity network which supplies 52,373 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 25,925 consumers. The Central region is characterised by its separate valley areas mandating a radial network supplied from three transmission grid exit points (GXPs). There are no high voltage interconnections between the Central GXPs. The Dunedin region is supplied from two GXPs with significant high voltage interconnection between them. A small embedded network was installed in Te Anau in 2005.

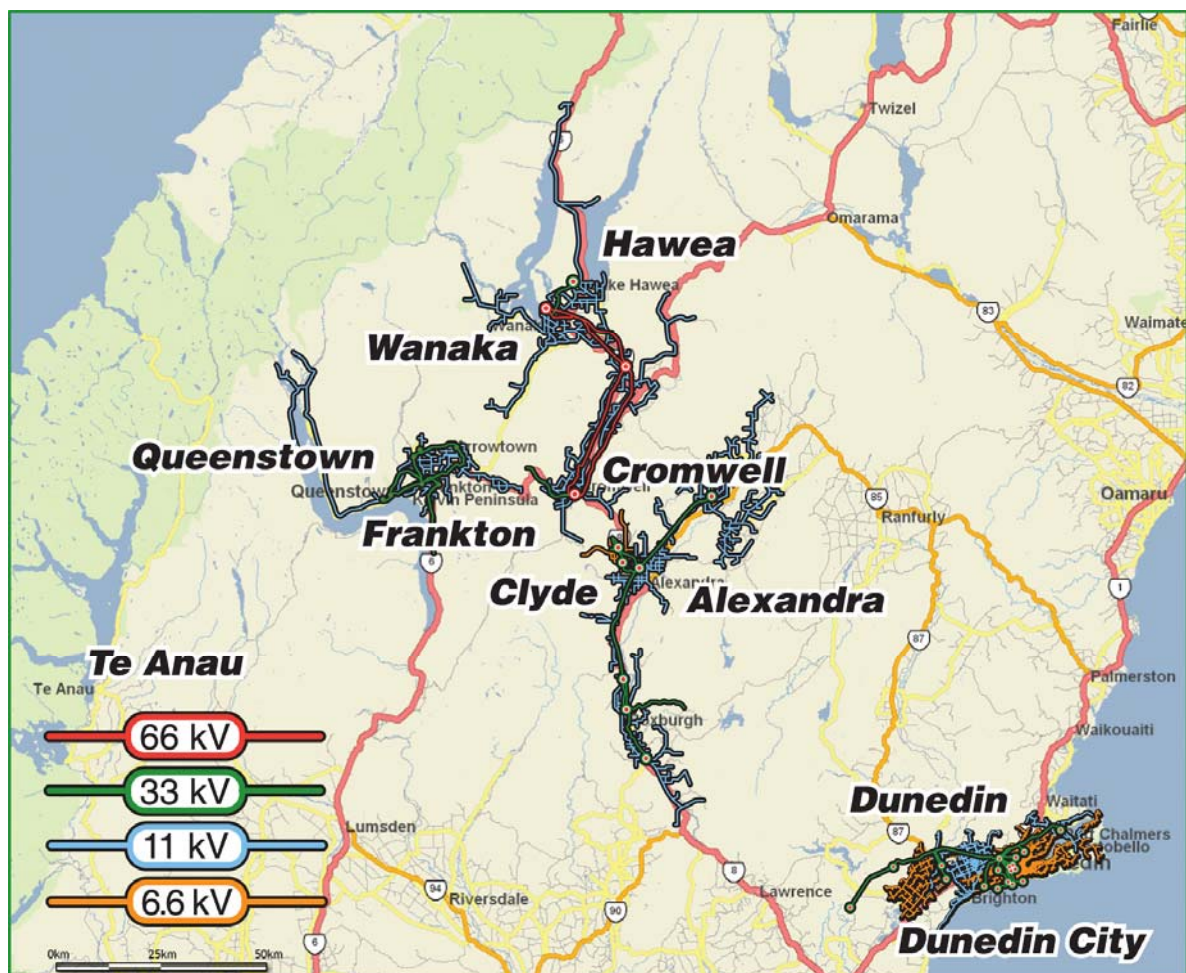


Figure 3.1 – Aurora Network

3.1.2 Large Consumers

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

3.1.3 Load Characteristics

The load in all areas is dominated by residential and commercial load. All GXP areas have their peak demand in winter. The daily peak loads for 2006 for each GXP are shown in Figure 3.2.

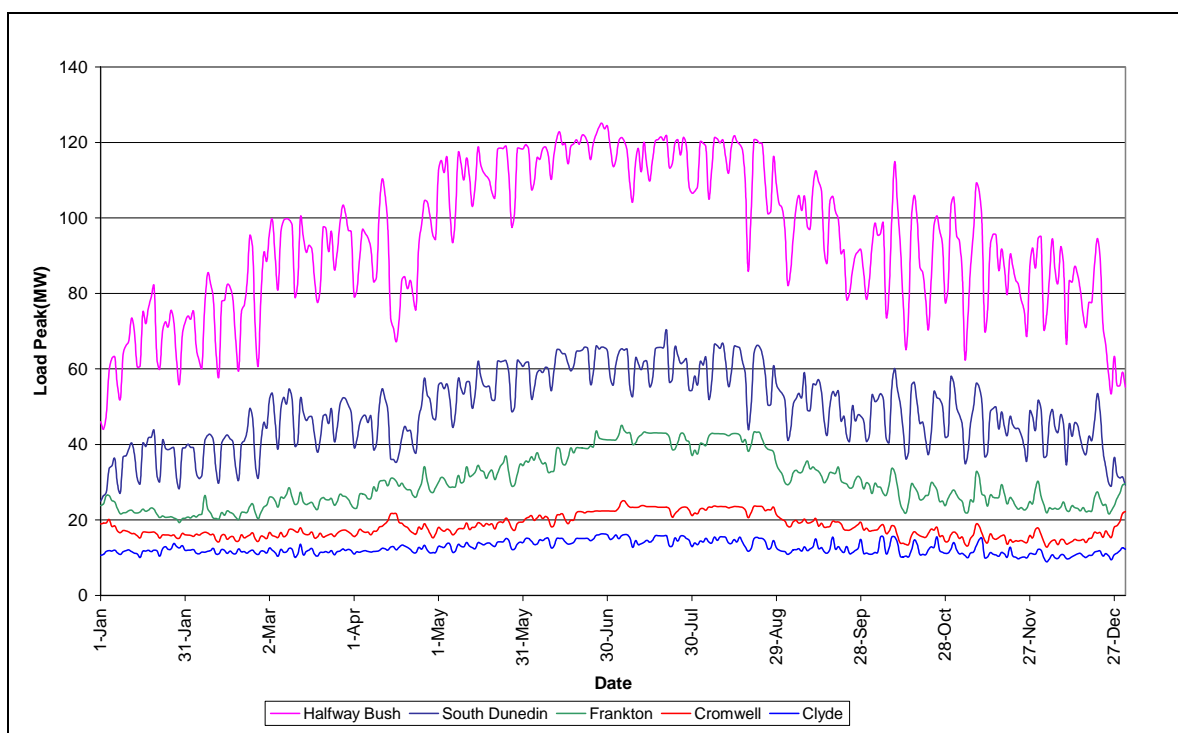


Figure 3.2 - Graph of Grid Exit Point Daily Load Peaks (2006)

The Frankton and Cromwell GXP peak loads usually occur during the July school holidays due to the influx of skiers into the area. There has been significant growth in summer irrigation load on the Cromwell GXP where the Queensberry zone substation has a summer peak.

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

Dunedin peak loads are very weather dependent and generally occur during a snow fall event in the city 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.

3.1.4 2006 Load Data

The key load and embedded generation statistics for the 2006 calendar year are presented in Table 3.1.

| GXP | Clyde | Cromwell | Frankton | Halfway Bush | South Dunedin | Total |
|---|--------------|-----------------|-----------------|---------------------|----------------------|--------------|
| 2006 peak MW | 16.3 | 25.1 | 45.1 | 125.1 | 70.2 | 281.8 |
| 2006 energy transported GWh | 103.3 | 118.0 | 204.5 | 614.3 | 325.7 | 1365.8 |
| Total number of ICPs | 6,378 | 8,838 | 10,419 | 35,600 | 16,366 | 77,601 |
| Off take n-1 capacity (24hr winter post contingency) MVA | 27 | 35 | 41 | 112 | 81 | |

Table 3.1 - GXP Load and Capacity Summary (2006 Calendar Year)

3.2 Network Configuration

The Aurora network is supplied from five Transpower GXPs as detailed above.

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

| GXP | Embedded Generation | Connection Voltage kV | Installed Generation Capacity MVA |
|---------------|---|----------------------------------|--|
| Halfway Bush | Waipori Ravensdown Fertiliser Dunedin Airport | 33 6.6 11 | 44 2.8 0.5 |
| South Dunedin | None | | |
| Frankton | Glenorchy Wye Creek | 11 33 | 0.5 1.3 |
| Cromwell | Roaring Meg Treble Cone (No export) | 33 11 | 4.3 1.0 |
| Clyde | Fraser Teviot | 33 33 | 2.5 14.8 |
| Total | | | 71.7 |

Table 3.2 - Schedule of Embedded Generation

3.3 Sub-Transmission

3.3.1 Dunedin Area

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

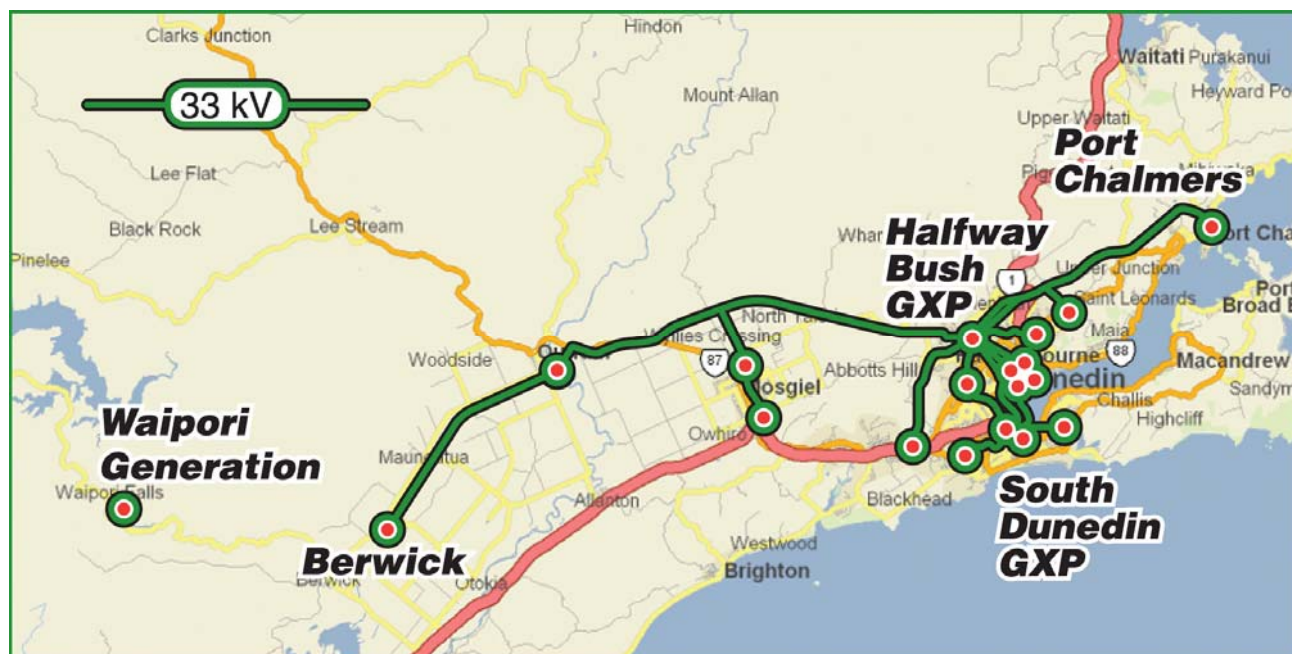


Figure 3.3 - Dunedin Sub-Transmission Network

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

Table 3.3 - Zone Substations in the Dunedin Area

3.3.2 Frankton Area

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

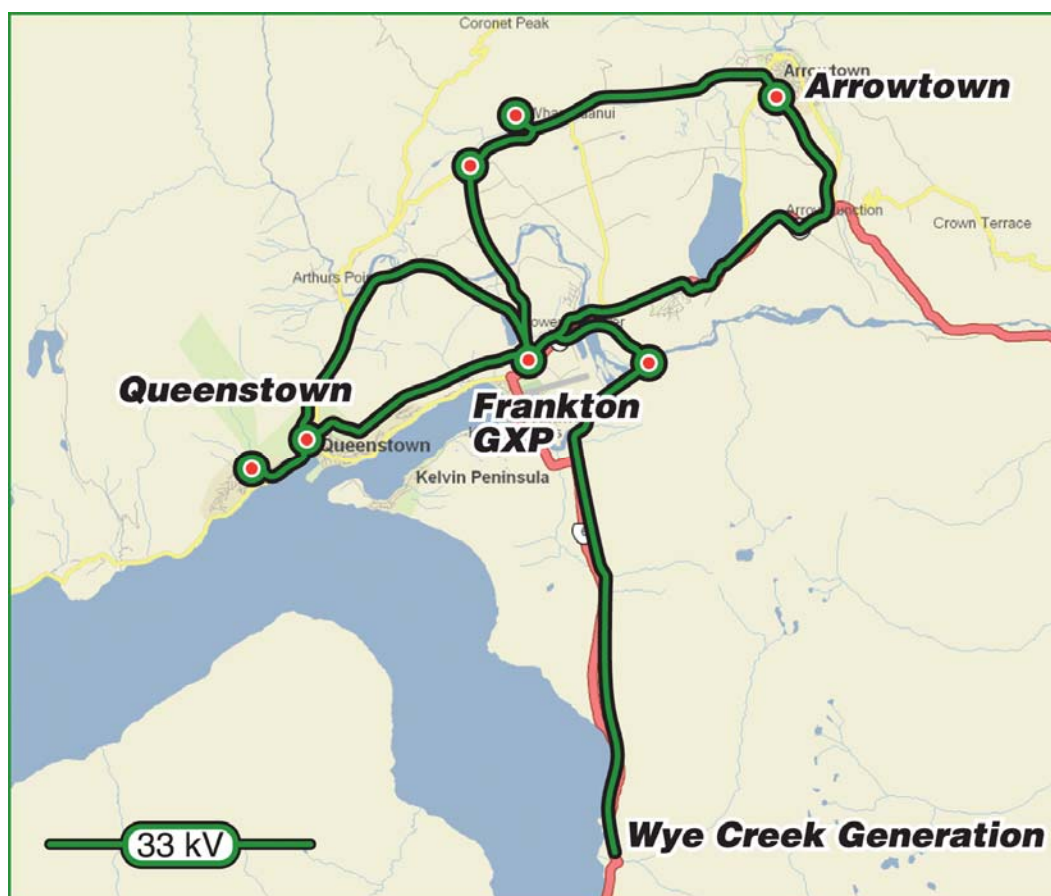


Figure 3.4 - Frankton Sub-Transmission Network

| Substation | Transformer MVA | Sub-Transmission Configuration | n-1 Security |
|--------------|-----------------|---|--------------|
| Arrowtown | 5 + 5 | Supplied from Wakatipu Basin 33kV ring | Y |
| Dalefield | 3 | Supplied from Wakatipu Basin 33kV ring | Y |
| Queenstown | 10/20 + 10/20 | Three 33kV lines from Frankton GXP | Y |
| Fernhill | 10 + 10 | Two 33kV cables from Queenstown | Y |
| Frankton | 7.5/10+7.5/15 | Tee off two of Queenstown to Frankton lines | Y |
| Remarkables | 1 | Tee off from Wakatipu Basin 33kV ring | N |
| Coronet Peak | 5 | Tee off from Wakatipu Basin 33kV ring | N |

Table 3.4 - Zone Substations in Frankton Area

3.3.3 Cromwell Area

The Cromwell area is supplied via four 33kV outlets at the Cromwell GXP. Two of the outlets supply two 33/66kV 30MVA auto transformers adjacent to the GXP that supply the Wanaka area via two parallel 66kV transmission lines. The other two outlets supply the Aurora Cromwell zone substation and provide a connection to the 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.

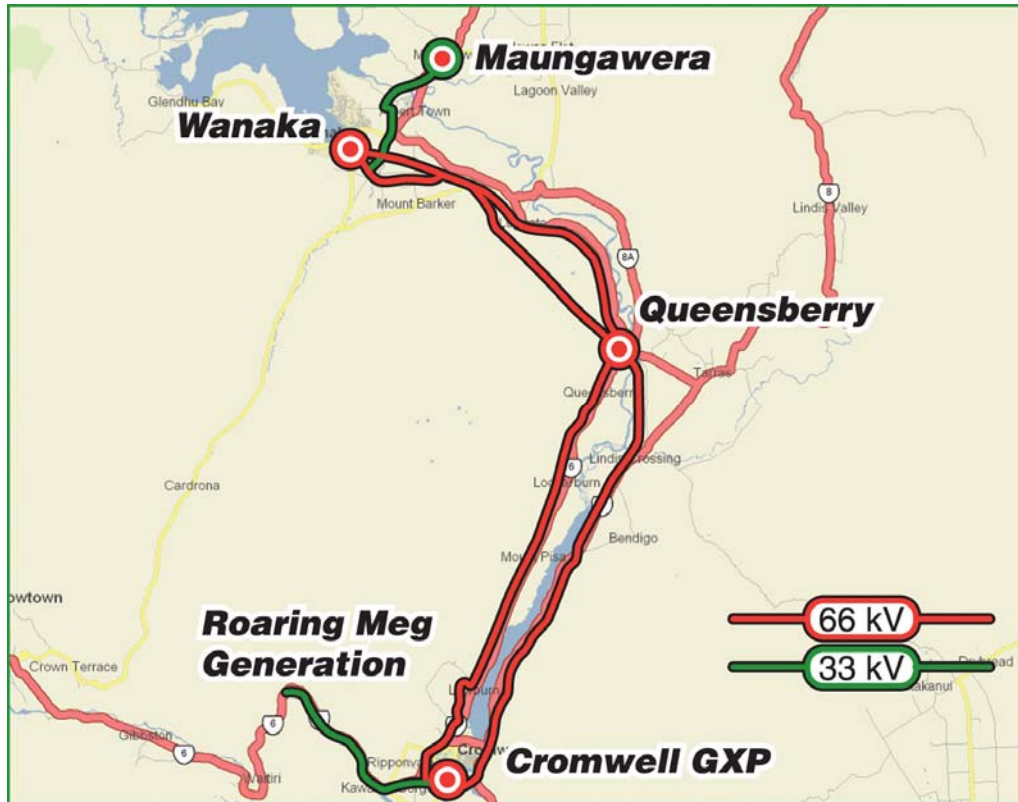


Figure 3.5 - Cromwell Sub-Transmission Network

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

Table 3.5 - Zone Substations in the Cromwell Area

3.3.4 Clyde Area

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

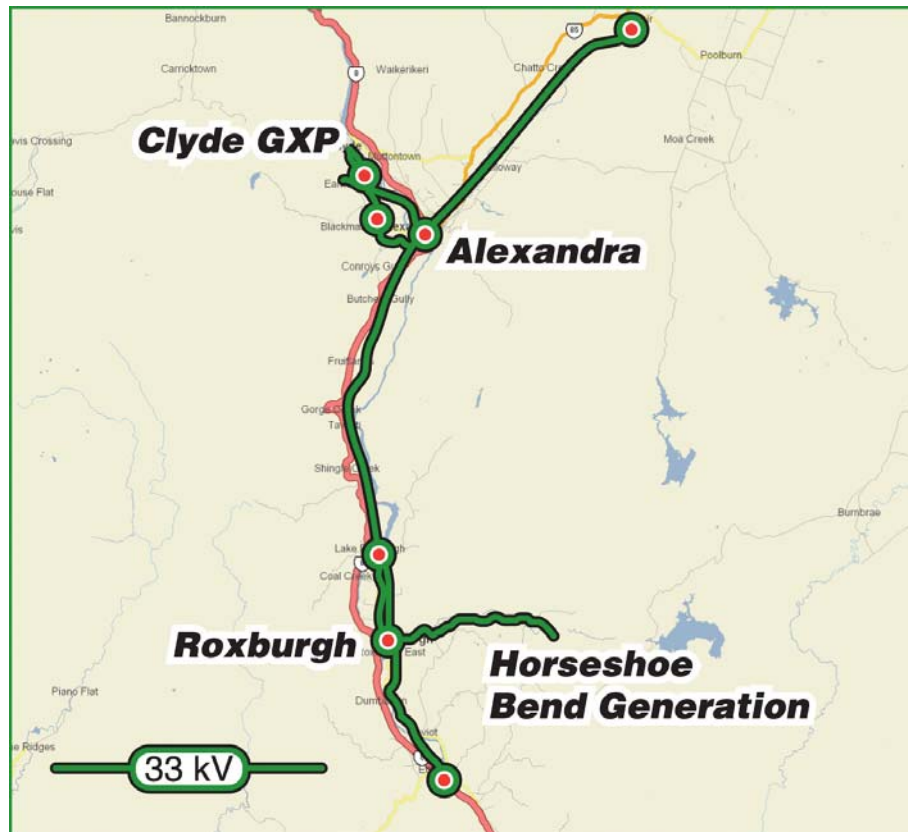


Figure 3.6 - Clyde Area Sub-Transmission

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

Table 3.6 - Clyde Area Zone Substations

3.4 HV Distribution

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

3.4.1 Dunedin Area

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

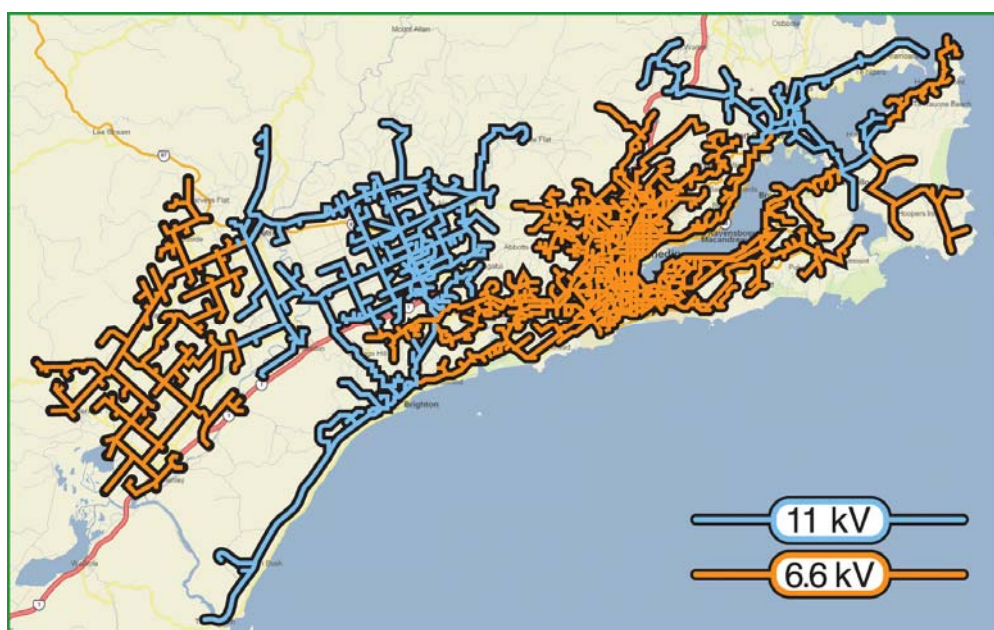


Figure 3.7 - Dunedin HV Distribution by Voltage

| Voltage | km | % Overhead | % Underground |
|---------|------|------------|---------------|
| 11kV | 332 | 83% | 17% |
| 6.6kV | 703 | 67% | 33% |
| Total | 1035 | 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. 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%) and XLPE (65%) and is unknown for 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.

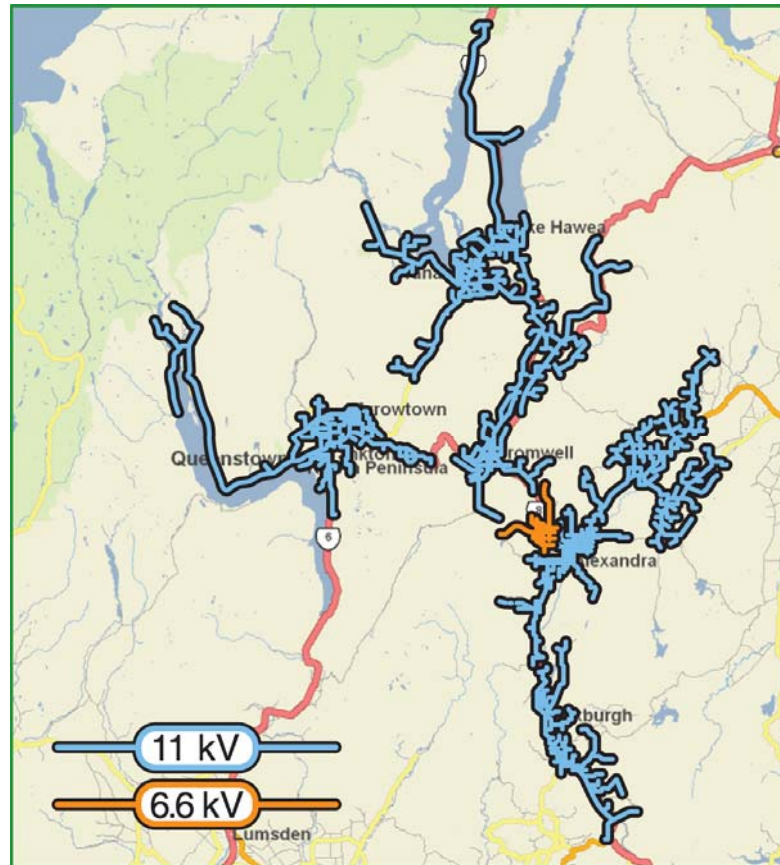


Figure 3.8 - Central HV Distribution by Voltage

| Voltage | km | % Overhead | % Underground |
|---------|-------|------------|---------------|
| 11kV | 1,980 | 78% | 22% |
| 6.6kV | 77 | 88% | 12% |
| Total | 2057 | 78% | 22% |

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

3.5 Distribution Substations

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 | 1843 |
| 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.

3.5.3 Ground Mounted

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

Cable Box/Cable Box (Standard)

This configuration is generally used when the transformer is dedicated to one consumer with the consumer's LV mains directly connected to the LV terminals of the transformer.

Package

This configuration consists of a specially configured transformer accommodated in a fibre-glass enclosure with associated HV switchgear and LV distribution board. This configuration is 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

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 | 1726 | 61% | 39% |

Table 3.10 - LV Distribution Quantities (As at 31/3/2007)

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

Central Load Control

The majority of load management in the Central area is via Decabit 317 Hz ripple injection plants, one at each GXP. There are approximately 24,000 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

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

3.7.6 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 2006 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 (See Note 1) | \$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 2) | \$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 Large reduction from 2005 count due to correction of processing error
- 2 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 system performance (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 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.

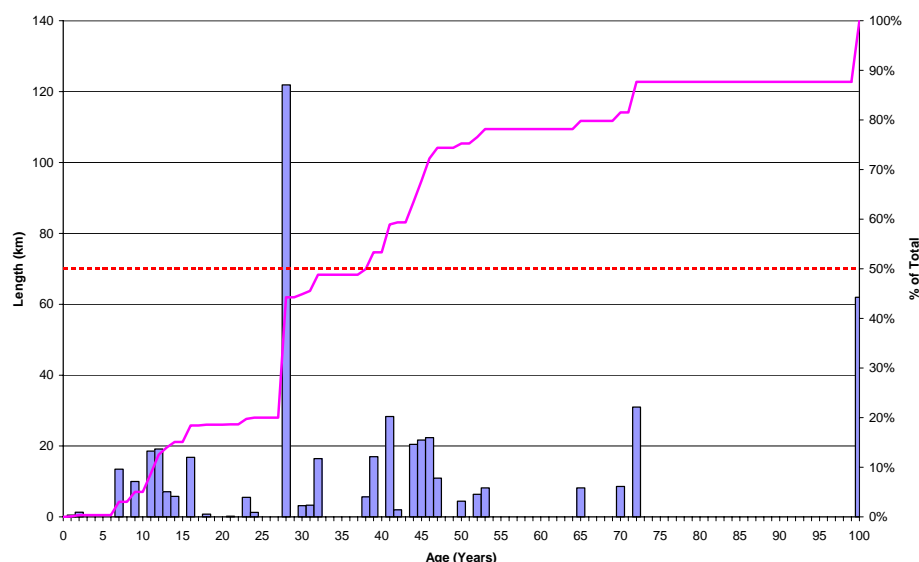


Figure 3.9 – 66 & 33kV Lines Age Profile (Total = 504)

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. The present condition of any line is a factor of its age, the environmental impacts of the locations it traverses and its maintenance history. A line located on the coast may have a life of about 30 years, limited by salt corrosion; however, the same line located inland will often be in excellent condition after 70 years. Generally, in coastal areas insulators will last about 30 years, conductors 40 years and poles over 45 years.

3.8.2 Subtransmission Cables

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

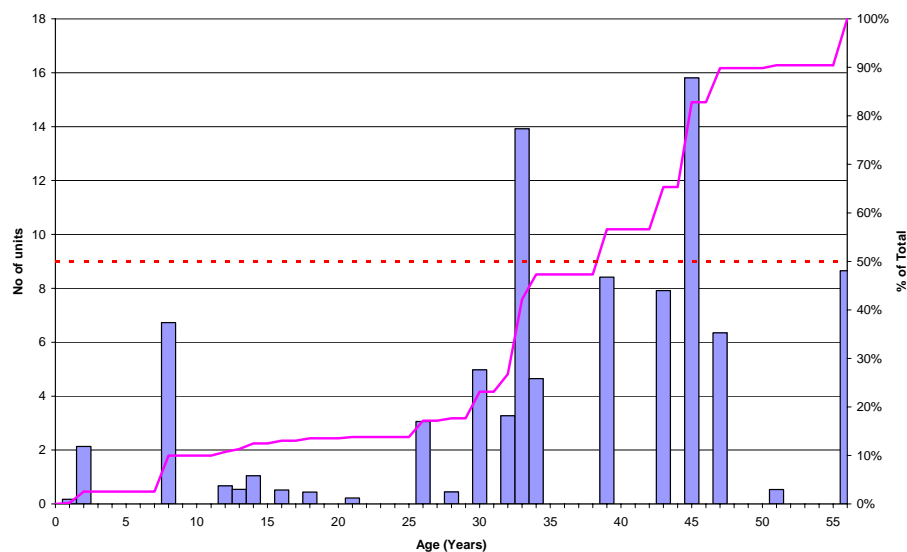


Figure 3.10 – 33kV Cables Age Profile (Total 90 km)

Following the Auckland CBD 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 are to be 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 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 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 St transformers are scheduled for replacement later in the planning period in association with a major upgrade of the substation.

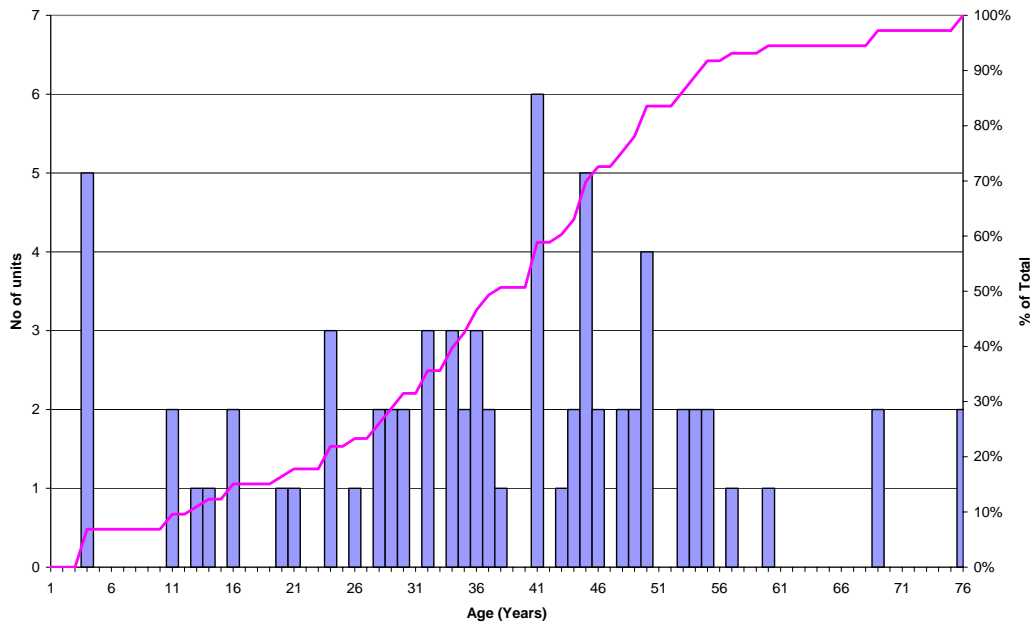


Figure 3.11 – 66 and 33kV Zone Substation Transformers Age Profile (Total = 73)

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.

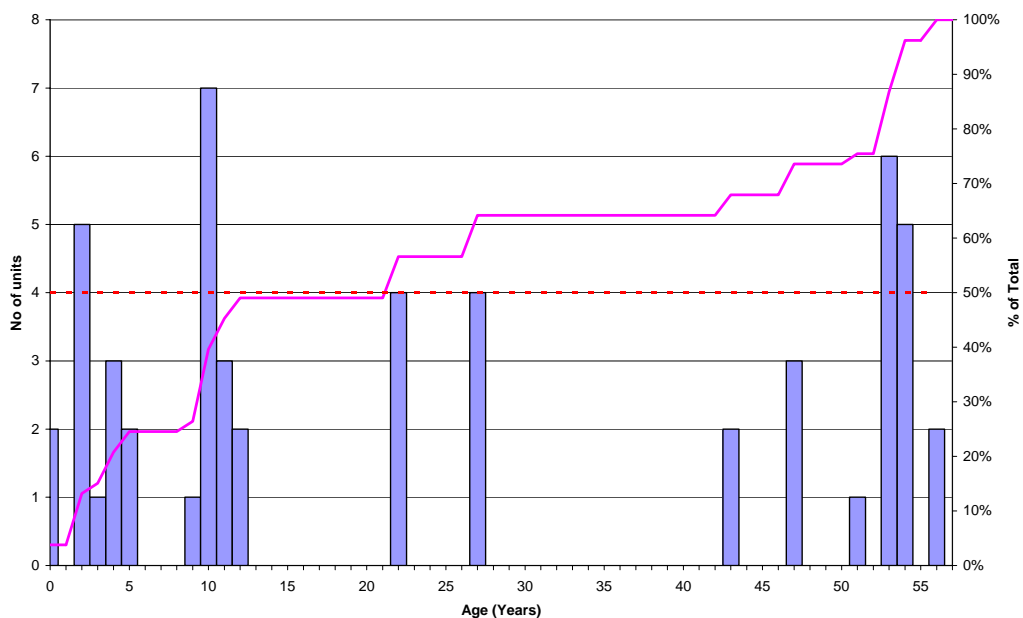


Figure 3.12 – 66 and 33kV Zone Circuit Breakers Age Profile (Total = 53)

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.

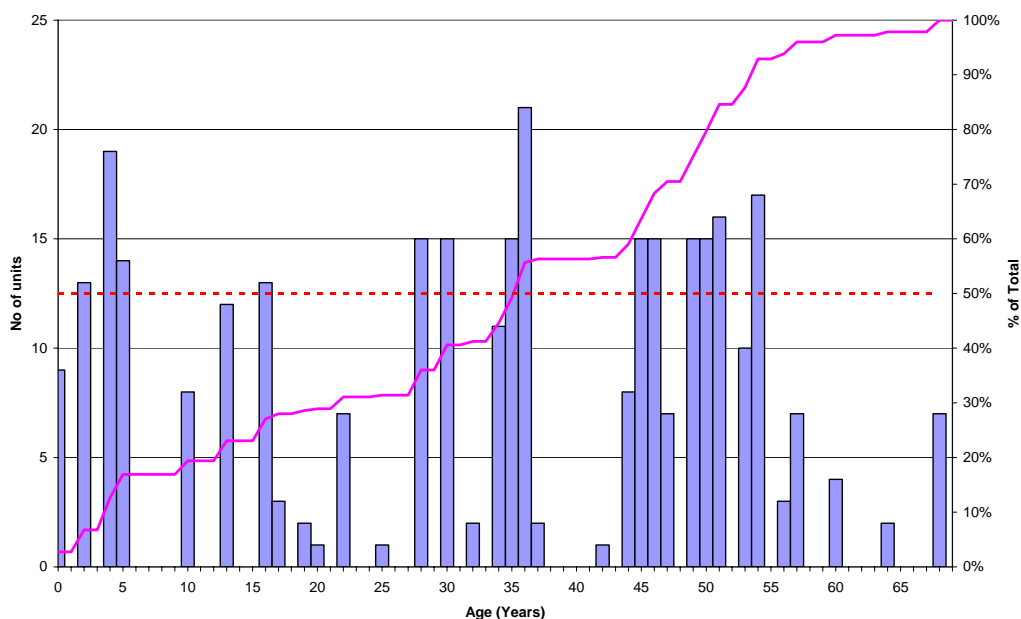


Figure 3.13 – 11 and 6.6kV Circuit Breakers Age Profile (total = 325)

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 | 2009/10 |
| Roxburgh | 1950 | Planned | 1 | 2008/09 |
| Frankton | 1950 | Planned | 8 | 2008/09 |
| 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 17 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 age related replacement requirements 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.

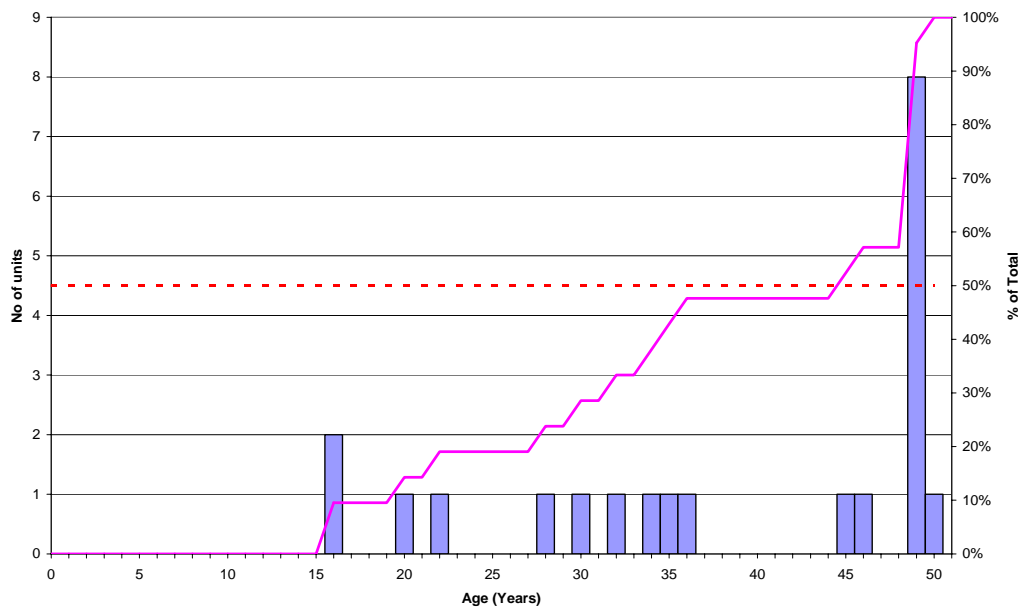


Figure 3.14 – Load Control Equipment Age Profile (Total = 21)

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.

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.

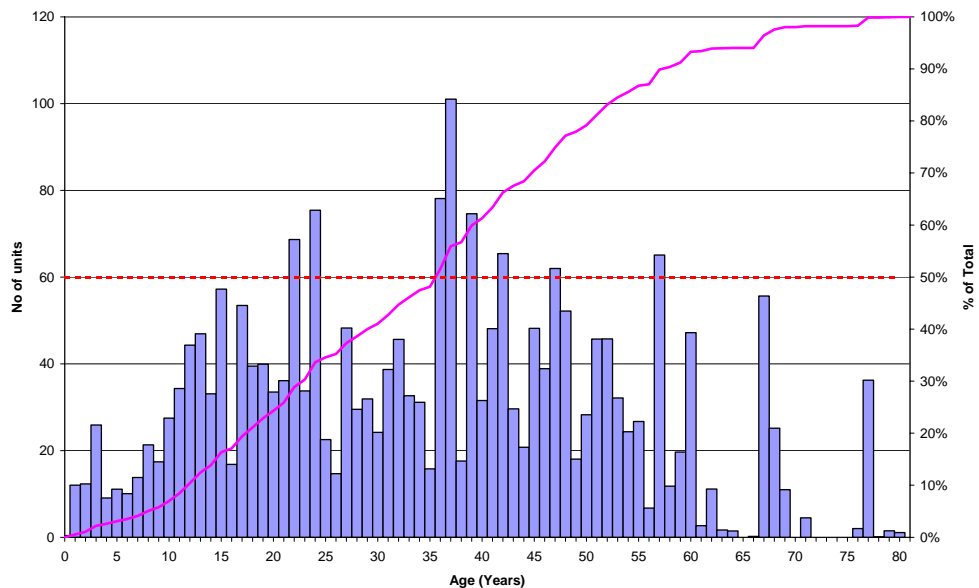


Figure 3.15 – 11kV & 6.6kV Lines Age Profile

3.8.12 HV Cables

The age profile of HV cables is shown in Figure 3.16. Aurora has 734 km of HV cable and 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.

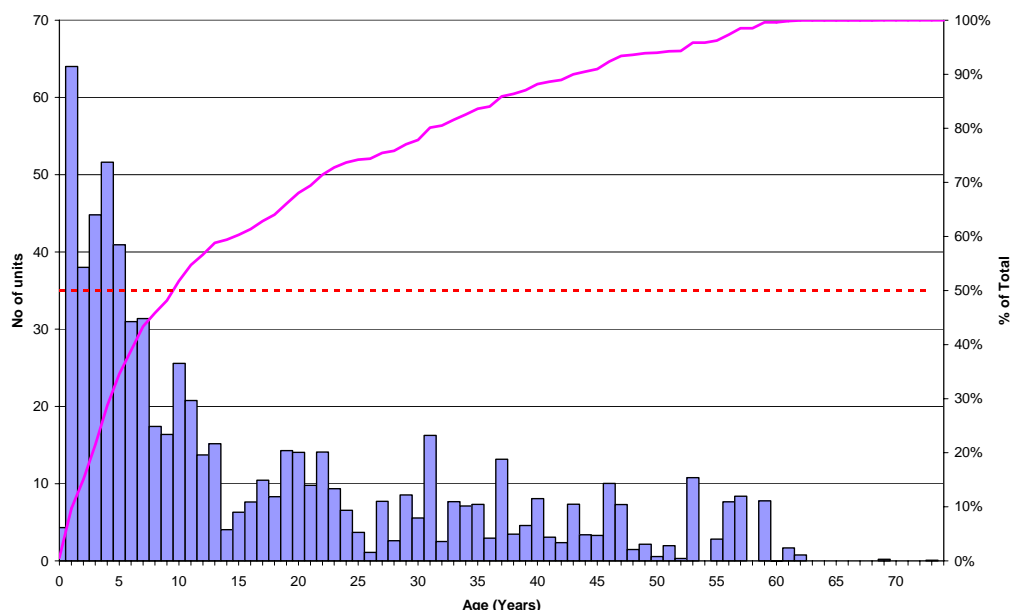


Figure 3.16 – 11 & 6.6kV Cables Age Profile (Total = 734 km)

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.

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

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

3.8.14 Distribution Transformers

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

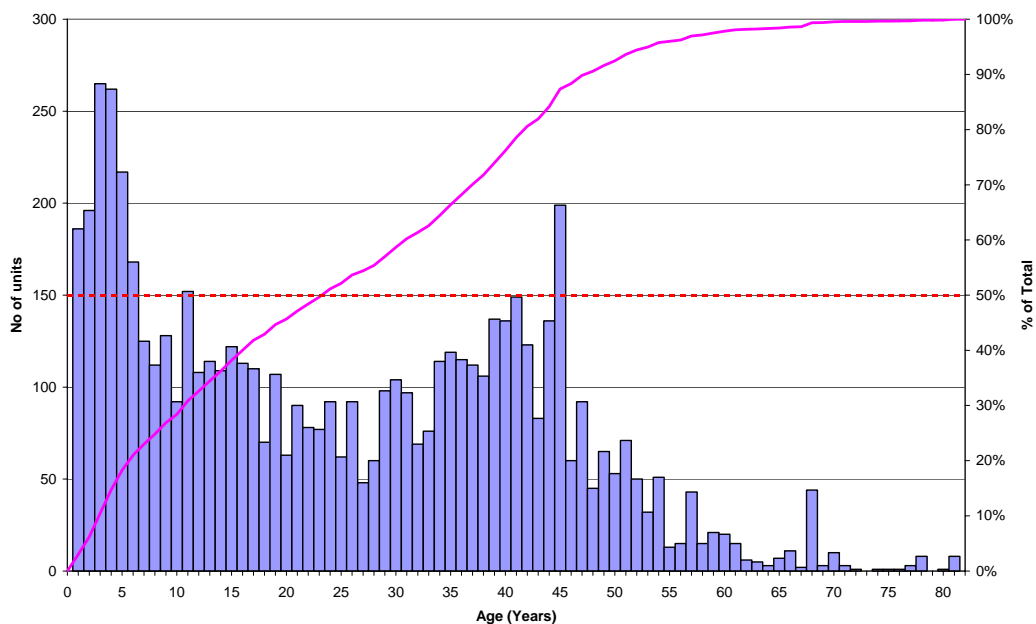


Figure 3.17 – Installed Distribution Transformers Age Profile (Total = 6220)

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.

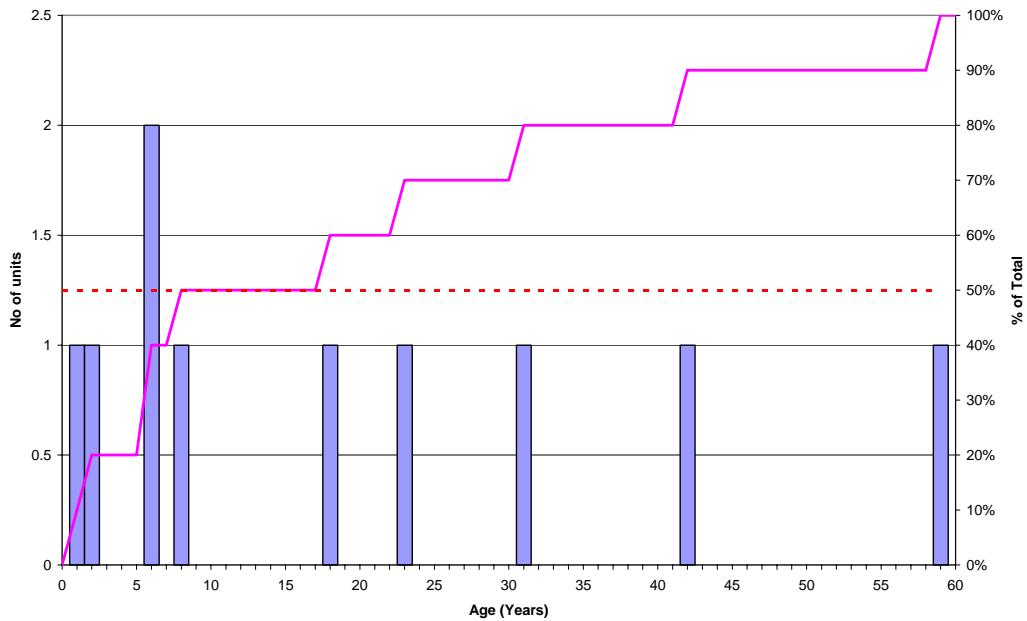


Figure 3.18 – HV Regulators Age Profile (10 Sites)

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 do not require excessive maintenance.

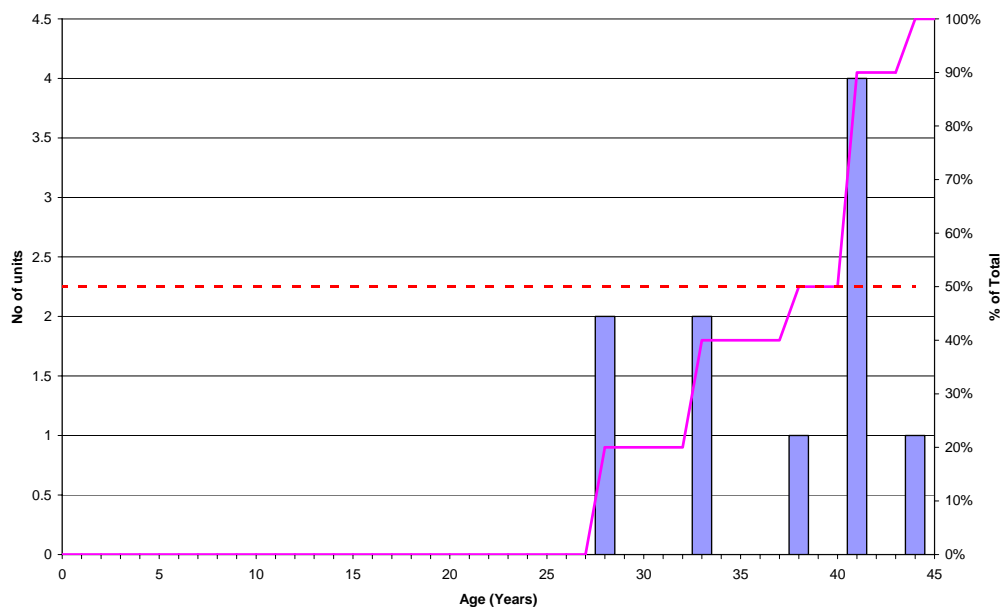


Figure 3.19 – HV Autotransformers Age Profile (10 Units)

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 plans to replace units at one major 11kV consumer site over the 2007/08 summer subject to consumer confirmation.

| 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

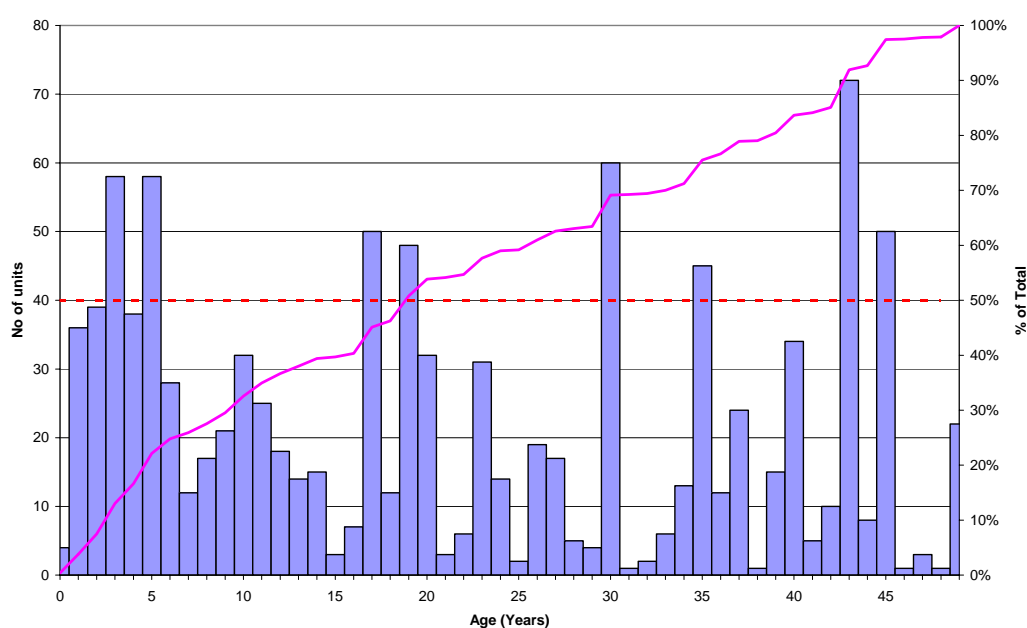


Figure 3.20 – HV Ground Mounted Switchgear Age Profile

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.

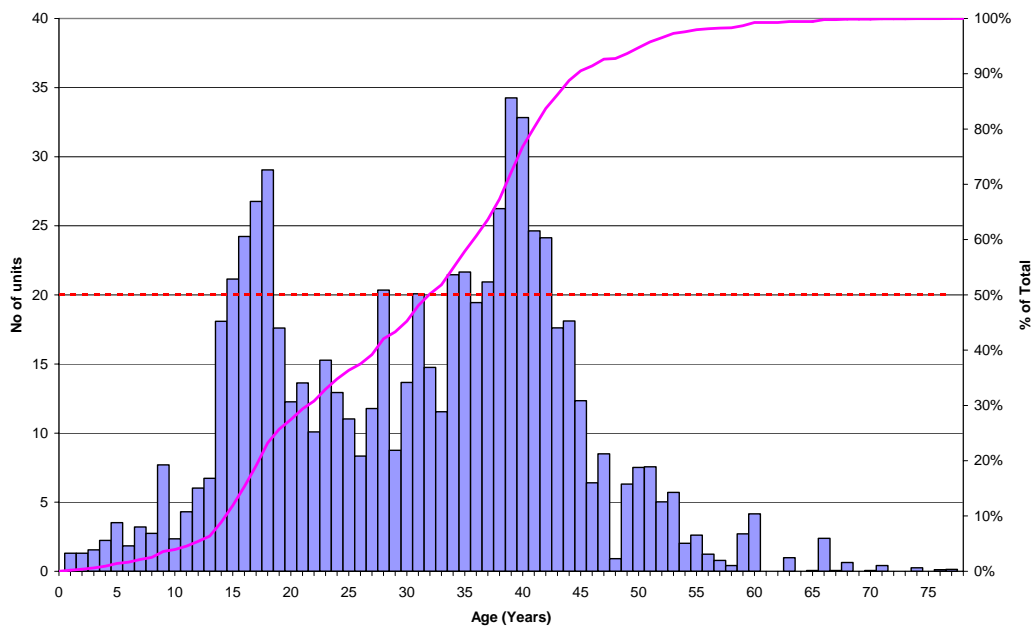


Figure 3.21 – LV Distribution Line Age Profile)

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

Part of the 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 and 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 used.

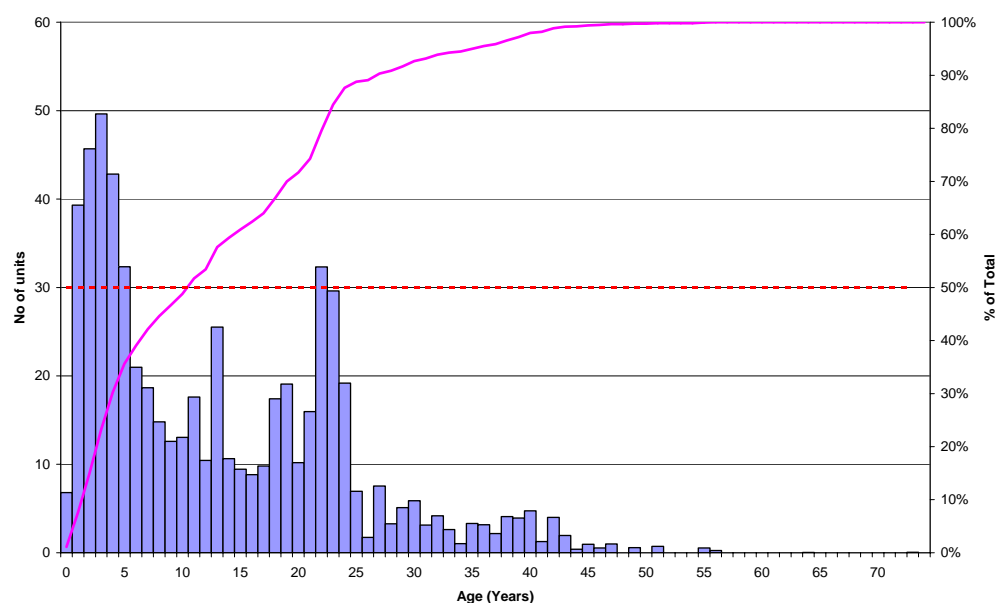


Figure 3.22 – LV Distribution Cable Age Profile

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 477 (1%) poles that have installation date allocated.

Figure 3.23 details the age profile.

A condition-based inspection regime is in place and there is no evidence of increased replacements being required in the planning period. Since 1990, softwood poles have been used as replacements for both concrete and hardwood poles but questions arose as to their longevity in the Central Otago environment. Investigation has confirmed that, as long as softwood poles are selected based on strict criteria, they should have an acceptable life. However, recent discussions with other asset owners and the yet-to-be published results of the June 2006 snow storm in Canterbury indicate the need to review softwood pole performance within the planning period.

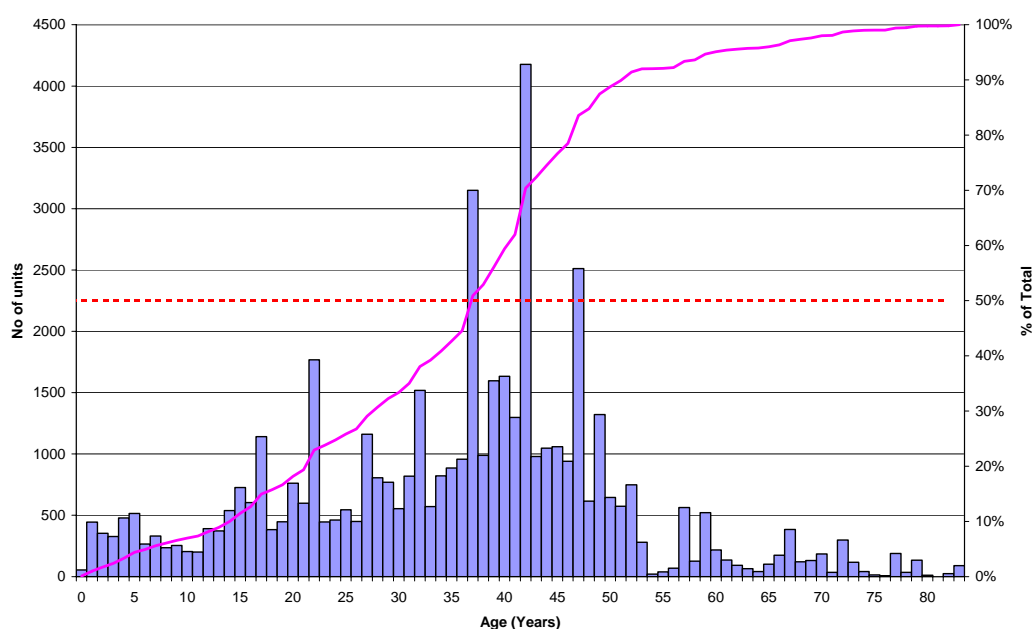


Figure 3.23 – Poles Age Profile

3.8.21 System Control Equipment

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

3.9 Justification for Assets

All assets are justified by present or anticipated requirements except for approximately 3.2% 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 in the 2004 ODV are detailed below:

HV Distribution Switchgear

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

HV Distribution

HV distribution lines and cables that were identified in the GIS as being “not in service” were optimised out. 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 last year) 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.

Sub Transmission

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 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 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 | 2002/03 | 2003/04 | 2004/05 | 2005/06 | 2006/07 |
|-------------------------|--------------|-------------|-------------|-------------|--------------|
| Unplanned | | | | | |
| Underlying | 55.7 | 56.6 | 67.8 | 70.8 | 61.3 |
| Significant Events | 12.9 | 23.4 | 5.4 | 0 | 22.3 |
| Transpower | 12.1 | 1.0 | 0.0 | 13.9 | 4.7 |
| Total Unplanned | 80.7 | 81.0 | 73.2 | 84.7 | 88.2 |
| Planned | | | | | |
| Underlying | 20.5 | 16.3 | 7.3 | 11.7 | 13.2 |
| Total | | | | | |
| Underlying | 76.2 | 72.9 | 75.1 | 82.5 | 74.5 |
| Significant Events | 12.9 | 23.4 | 5.4 | 0 | 22.2 |
| Transpower | 12.1 | 1.0 | 0.0 | 13.9 | 4.7 |
| Disclosure Total | 101.2 | 97.3 | 80.5 | 96.4 | 101.4 |
| Other (LV etc) | 0.8 | 0.1 | 0.9 | 0.5 | 0.5 |
| Overall Total | 101.8 | 97.4 | 81.4 | 96.9 | 101.9 |

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

As detailed elsewhere, *the intention is to hold SAIDI constant*, at the levels shown in Table 4.2. Analysis of the reliability data for other distribution networks in New Zealand reveals a present average figure of 148 minutes without supply per consumer per year.

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

Table 4.2 – Network Performance Target (SAIDI) (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:

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

Table 4.3 – Network Performance Target (SAIFI)

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

4.1.2 Restoration of Electricity Delivery and Service Interruption Investigations

Restoration of electricity delivery following a general network failure

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

- (i) \$50 (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 324 ICPs were made in the year ending 31 March 2007.

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 2007, 5,285 (7%) urban consumers experienced more than four interruptions and 1,715 (17%) 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. Such physical asset performance measures can be found on Aurora's website www.electricity.co.nz within the Information Disclosure material therein.

4.2.1 Voltage Range

A minimum and maximum voltage is set by statutory requirement for the protection of consumer appliances, but excludes "momentary" fluctuations. Voltage excursions outside of the statutory range will occur because of equipment failure, environmental effects (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.

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.

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

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 |
| Consumers Surveyed | 4,327 | 4,554 | 4,641 | 4,603 | 4,752 |
| Response Rate | 20% | 18% | 18% | 18% | 16% |
| Responses | | | | | |
| Prefer higher quality | 9.3% | 7.4% | 6.7% | 5.3% | 5.9% |
| Prefer lower price | 90.7% | 92.6% | 93.3% | 94.7% | 94.1% |

Table 4.4 – Price Versus Quality Survey

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

As supply quality moves nearer to that required by the majority of consumers, there is increased risk that a minority will receive lesser quality than they wish. Options to provide higher quality for specific needs will be available (and involve additional charges) but will be limited by network topology. However, demand-side options (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 ³ |
|-----------------------------|---|
|-----------------------------|---|

³ *Reliability of Electricity Supply*, Canterbury University Centre for Advanced Engineering, 1993, p.111.

| Type of Interruption | Value of kWh Unserved ³ |
|-------------------------|------------------------------------|
| 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 measure chosen to monitor overall asset performance is the System Average Interruption Duration Index (SAIDI), since it combines both interruption frequency and interruption duration, and the plan provides to hold it at present levels. Acceptance by users of the standard Use-of-System agreement indicates acceptance of this strategy.

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

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

4.2.4 Frequency of Interruption

An acceptable overall level of SAIDI can disguise local reliability that is significantly worse than average. For some years, Aurora has monitored "FAIDI" (feeder customer-minutes divided by feeder customer number, for each feeder) to ensure that the performance of the worst feeders is apparent. For "problem feeders" consumers are more sensitive to frequency of interruptions, and this is receiving specific attention. Examples of such analysis are shown in Figure 5.3 and Figure 5.4 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 sub-transmission and distribution lines through its maintenance programmes by, for example, ensuring that vegetation is maintained clear from lines. Similarly, substation fences and gates and other equipment enclosures are kept in good order.

One report of electric shock in 2003 resulted from poor earth installation. There have been no other 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.

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.

| | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 |
|--------------------------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| 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 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 | 3,100 |
| System development including SCADA | 700 | 700 | 700 | 700 | 700 | 700 | 700 | 700 | 700 | 700 |
| Subtransmission and zone substations | 3,170 | 3,340 | 3,800 | 3,710 | 4,550 | 4,940 | 5,350 | 5,770 | 6,060 | 5,550 |
| Undergrounding | 1,880 | 2,370 | 2,410 | 2,450 | 2,490 | 2,530 | 2,580 | 2,630 | 2,680 | 2,730 |
| Total | 17,050 | 17,710 | 18,210 | 18,160 | 19,040 | 19,470 | 19,930 | 20,400 | 20,740 | 20,280 |

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 owned by other utilities - mainly Telecom.

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)
- Commonage zone substation (5.11.8)
- Ward Street substation replacement (6.5.3)
- Berwick transformer and 33 kV switchgear 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.

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. Draft regulations for Distributed Generation are expected to become effective during late 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 draft Electricity Governance (Connection of Distributed Generation) Regulations 2007.

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.

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%) 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 sub-transmission and zone substation level. Aurora uses the n-1 criteria as a screening tool to identify which parts of its sub-transmission and zone substation network require the application of probabilistic analysis to determine 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. Budgetary estimates for each project are produced.

There are usually multiple options to resolve most network capacity constraints. Aurora generally selects the option with the lowest life cycle cost, by comparing the NPV of the following costs associated with a project:

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

Other factors that may be taken into consideration during project selection are environmental impact, community feedback and future 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. |
| 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. |
| Distribution transformers | Transformers with a normal residential area load profile can be loaded to 150% of nominal rating. For other loads 130% of nominal rating. |

Table 5.3 – Assignment of Equipment Ratings

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

Table 5.4 – Parameters Used to Determine Overhead ACSR Conductor Ratings

5.9 Grid Exit Points

5.9.1 Demands and Growth Predictions

The history of peak demands (in MW) for the network areas associated with each GXP are shown below and are equal to the demand on the GXP plus embedded generation (see Table 5.5 and Figure 5.2).

| Calendar Year | | | Clyde | Cromwell | Frankton | Halfway Bush | South Dunedin |
|---|-----------|---|-------|----------|----------|--------------|---------------|
| 1999 | Actual | GXP Off take + Embedded Generation (MW) | 15.4 | 16.5 | 32.9 | 114.7 | 61.3 |
| 2000 | | | 14.7 | 17.4 | 34.6 | 121.7 | 62.4 |
| 2001 | | | 15.0 | 21.1 | 38.0 | 124.7 | 61.7 |
| 2002 | | | 17.1 | 19.9 | 37.4 | 133.0 | 65.9 |
| 2003 | | | 15.2 | 20.2 | 38.3 | 116.4 | 61.2 |
| 2004 | | | 15.6 | 21.5 | 41.4 | 124.0 | 67.0 |
| 2005 | | | 15.6 | 24.4 | 41.8 | 126.0 | 66.1 |
| 2006 | | | 16.3 | 25.1 | 45.1 | 125.1 | 70.2 |
| 2007 | Predicted | | 16.1 | 26.6 | 46.4 | 127.5 | 70.8 |
| 2008 | | | 16.3 | 28.0 | 48.3 | 128.8 | 70.9 |
| 2009 | | | 16.4 | 29.6 | 50.3 | 130.1 | 71.6 |
| 2010 | | | 16.6 | 31.3 | 52.4 | 131.4 | 72.3 |
| 2011 | | | 16.8 | 33.0 | 54.5 | 132.7 | 73.1 |
| 2012 | | | 16.9 | 34.9 | 56.8 | 134.0 | 73.8 |
| 2013 | | 17.1 | 36.8 | 59.1 | 135.3 | 74.5 | |
| Past growth rate (trend 1999 to 2006) | | | 0.9% | 5.6% | 4.1% | 0.7% | 1.7% |
| Growth rate for planning (See 3.1) | | | 1.0% | 5.6% | 4.1% | 1.0% | 1.0% |
| Off take n-1 capacity (24hr winter post contingency) MVA | | | 27 | 35 | 41 | 112 | 81 |

Table 5.5 – GXP Area Peak Demands

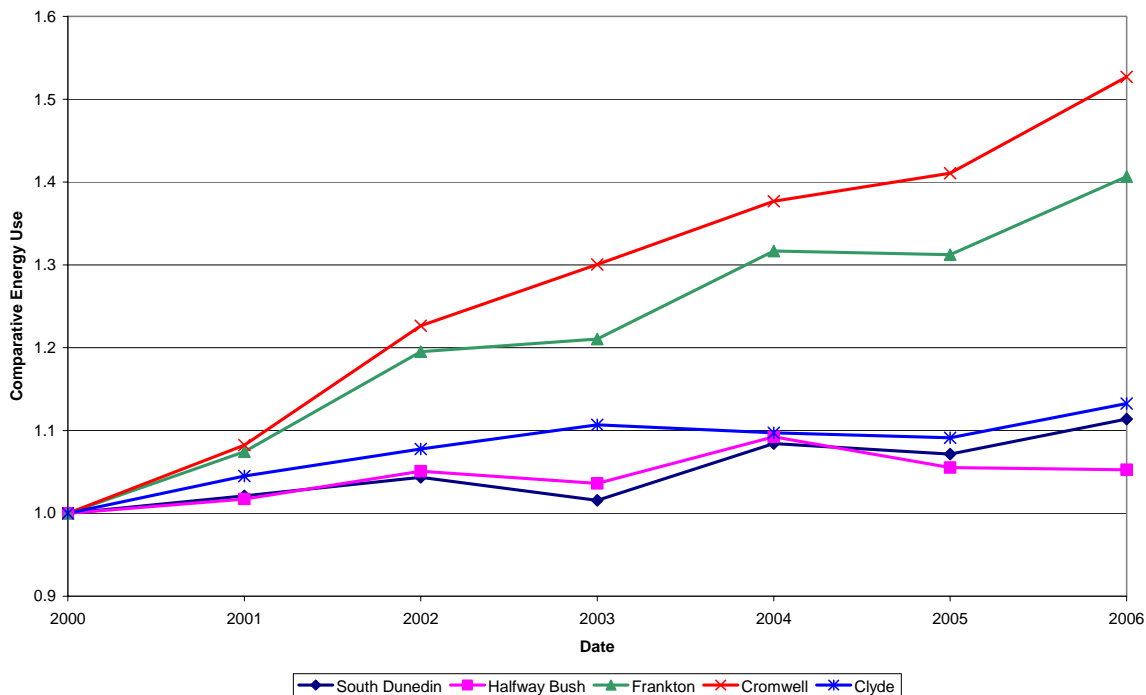


Figure 5.1 – Comparative Growth in GXP Energy (GWh 2000 Normalised)

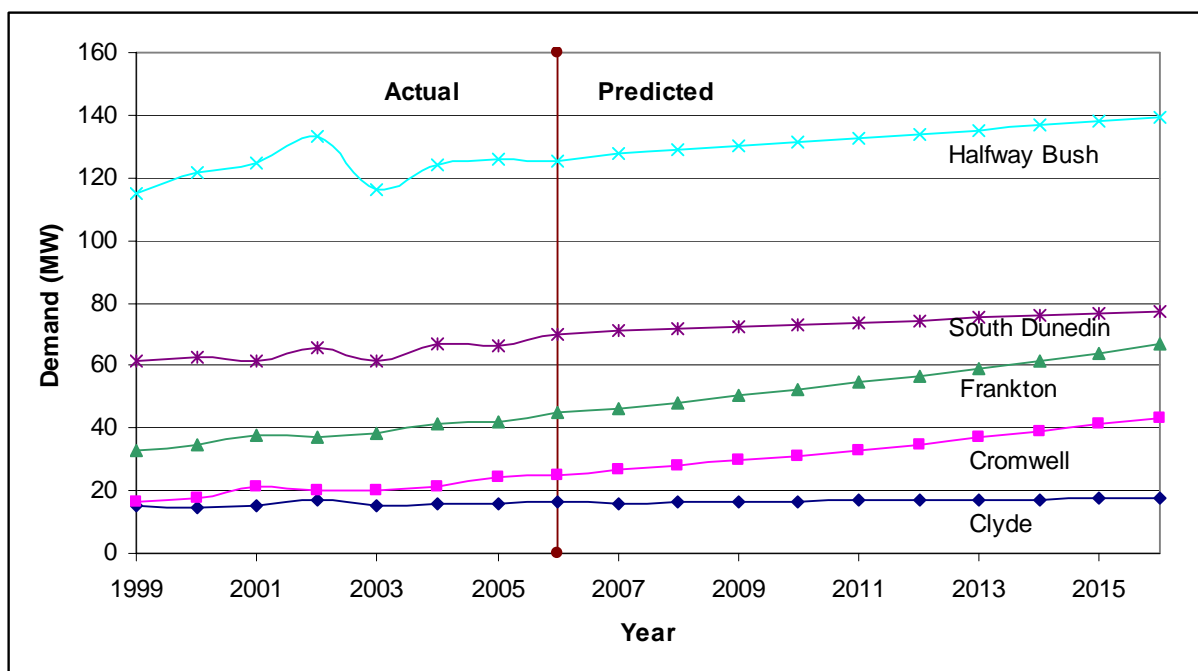


Figure 5.2 – GXP Peak Demands (Includes embedded generation)

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 3 day snow fall in May.

Strong growth is predicted to continue in the Frankton and Cromwell GXP areas and more modest growth in the Clyde and Dunedin GXP areas. 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 2 MW load transfer from the Halfway Bush GXP.

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 2006 peak off take on the Frankton GXP was 44.3 MW (45.2 MVA at 0.98 power factor excluding embedded generation). This exceeds the 41 MVA 24hr post contingency rating of the transformers. Transpower is increasing the transformer capacity by paralleling the existing 40 MVA transformers and installing a new 85 MVA transformer.

If there is a failure in the Transpower network between Twizel, Clyde and the Frankton GXP, during the winter of 2007, then at peak loads it will be necessary to shed load. An automatic load shedding scheme has been installed by Transpower on the Dalefield and Arrowtown 33 kV feeders.

In conjunction with the transformer upgrade, Aurora requested two additional 33kV outlets from Transpower to facilitate the separation of the Frankton substation from the Queenstown feeders. A third party has also requested two 33kV outlets. The addition of four outlets was beyond the capacity of the existing outdoor switchyard so a new 33kV indoor switchboard is being installed. The installation of the new switchboard requires Aurora to reconnect its 33kV feeders to the new switchgear via cable.

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 supply both the 33kV to the Cromwell GXP and the 110kV supply to the Frankton GXP. The transformers are rated as 85/50/35 MVA for their 220kV, 110kV and 33kV windings respectively. The 2006 combined Cromwell and Frankton GXP demand was approximately 70MVA.

It is expected that the 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. Transpower is preparing a report on the proposed upgrade with completion of the upgrade proposed 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 17 MVA, based on 2006 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 2006, one of the Clyde GXP transformers failed and is presently being repaired. A contingency plan has been organized and Transpower have placed a 10 MVA transformer at the Roxburgh switchyard to support local generation in the event of the remaining transformer failing. It is expected that the repaired transformer will be returned to service by November 2007.

5.9.5 Halfway Bush GXP

The off-take peak at Halfway Bush exceeds the HWB 112 MVA post contingency rating. This is not of 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 St substation load to the South Dunedin GXP when the Neville St 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 70.2 MVA but if the Neville St Substation load is transferred to South Dunedin the load would be very close to 81 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 sub-transmission from the Frankton GXP to Queenstown is constrained by the 33kV cables into the Queenstown substation. This is to be resolved by upgrading the cables over the 2007/08 summer and installing a new substation in the Commonage area on Queenstown Hill. The new Commonage substation is described in Section 5.11.7 below.

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. It is proposed to install a 500kW diesel generator before the 2008 winter to support the 11kV transmission. 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 but has yet to obtain resource consent. If this project proceeds, a 33kV line will be needed from Maungawera to Hawea (6 km) and the existing 33kV cable and line between Wanaka and Maungawera will require upgrading. It is proposed that the new line follows the route of the existing 11kV line in a 33kV over 11kV configuration. Contact's preliminary timetable, which requires confirmation, is to begin commissioning by January 2009. Resource and land owner consent will be required for this project. The estimated cost is \$1,000,000.

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 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 and Jack's Point substations are commissioned there will be a reduction in load of the substation 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 will 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 outlets 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 sub-transmission system. The loss of a transformer at Queenstown is not considered to be a problem due to adequate inter-ties to Frankton and Fernhill.

| Zone Substation | Transformer MVA | Firm Load MVA | n-1 | Historical Demands MVA | | | | | | Previous Growth %/yr | Predicted Growth %/yr | Predicted Future Demands MVA | | | | | | | | | | | |
|-------------------|-----------------|---------------|------|--|------|------|------|------|------|----------------------|-----------------------|------------------------------|------|------|------|------|------|------|------|------|------|----------------|---------------|
| | | | | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | | | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2016 U.F. Firm | 2016 UF (n-1) |
| Alexandra | 7.5/15+7.5/15 | 15 | 15 | 10.8 | 11.1 | 10 | 10.4 | 10.8 | 10.9 | 0.0% | 0.5% | 10.9 | 11.0 | 11.0 | 11.1 | 11.1 | 11.2 | 11.3 | 11.3 | 11.4 | 11.4 | 76% | 76% |
| Anderson's Bay | 15 + 15 | 18 | 18 | 15.8 | 15.5 | 13.5 | 15.3 | 14.6 | 14.9 | -1.0% | 0.5% | 15.0 | 15.0 | 15.1 | 15.2 | 15.3 | 15.3 | 15.4 | 15.5 | 15.6 | 15.7 | 87% | 87% |
| Arrowtown | 5 + 5 | 7.5 | 6 | 6 | 5.6 | 6.3 | 6.3 | 6.4 | 7.2 | 3.3% | 2.0% | 7.3 | 7.5 | 7.6 | 6.6 | 6.7 | 6.9 | 7.0 | 7.1 | 7.3 | 7.4 | 97% | 121% |
| Berwick | 0.9+0.9 | 2 | 0 | 0.9 | 1.2 | 1.2 | 1.1 | 1.1 | 1.1 | 2.0% | 2.0% | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 | 1.3 | 1.3 | 1.3 | 1.3 | 1.4 | 66% | N/A |
| Clyde/Earnscleugh | 4 +2 | 4.8 | 4 | 4.1 | 4.7 | 4.1 | 3.6 | 3.6 | 3.7 | -4.4% | 0.5% | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.9 | 3.9 | 81% | 97% |
| Coronet Peak | 5 | 6 | 0 | * | * | * | 3.0 | 4.4 | 3.6 | N/A | 3.0% | 3.7 | 3.8 | 3.9 | 4.0 | 4.1 | 4.2 | 4.4 | 4.5 | 4.6 | 4.8 | 77% | N/A |
| Corstorphine | 12/24 + 12/24 | 23 | 23 | 13 | 13.5 | 12.2 | 13.1 | 12.5 | 12.8 | -0.7% | 0.5% | 12.9 | 12.9 | 13.0 | 13.1 | 13.1 | 13.2 | 13.3 | 13.3 | 13.4 | 13.5 | 58% | 58% |
| Cromwell | 5/10 + 7.5 | 9.0 | 9.0 | 6.2 | 6 | 6.6 | 7.1 | 6.8 | 7.9 | 4.1% | 3.5% | 8.1 | 8.4 | 8.7 | 9.0 | 9.3 | 9.7 | 10.0 | 10.4 | 10.7 | 11.1 | 119% | 119% |
| Dalefield | 3 | 3.6 | 0 | 3 | 3 | 3 | 1.4 | 1.9 | 1.8 | N/A | 2.5% | 1.9 | 1.9 | 2.0 | 2.0 | 2.1 | 2.1 | 2.2 | 2.2 | 2.3 | 2.4 | 64% | N/A |
| Earnscleugh | 2 | | | Used to increase Clyde/Earnscleugh firm capacity to 4.8MVA | | | | | | | | | | | | | | | | | | | |
| East Taieri | 12/24 + 12/24 | See Text | 18.5 | 13.4 | 14.7 | 13.6 | 14.2 | 14.9 | 15.7 | 2.3% | 3.0% | 16.2 | 16.7 | 17.2 | 17.7 | 18.2 | 18.7 | 19.3 | 19.9 | 20.5 | 21.1 | Note 1 | |
| Ettrick | 3 | 3.6 | 0 | 1.6 | 2 | 2 | 1.8 | 2.0 | 1.5 | -1.1% | 0.5% | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 45% | N/A |
| Frankton | 7.5/15 +7.5/10 | 12 | 10 | 7.7 | 7.9 | 7.8 | 8.0 | 9.0 | 10.4 | 4.7% | 5.0% | 11.0 | 11.0 | 9.6 | 10.0 | 10.5 | 11.1 | 11.6 | 12.2 | 12.8 | 13.5 | 107% | 128% |
| Fernhill | 7.5/10+7.5/10 | 10 | 10 | 5.1 | 4.8 | 5.2 | 5.2 | 5.4 | 5.6 | 2.1% | 2.5% | 5.7 | 5.9 | 6.0 | 6.2 | 6.3 | 6.5 | 6.6 | 6.8 | 7.0 | 7.2 | 70% | N/A |
| Green Island | 15 + 15 | 18 | 18 | 13 | 12.5 | 12.9 | 13.6 | 13.8 | 14.0 | 2.0% | 2.0% | 14.3 | 14.6 | 14.9 | 15.2 | 15.5 | 15.8 | 16.1 | 16.4 | 16.7 | 17.1 | 93% | 93% |
| Halfway Bush | 15 + 15 | 18 | 18 | 14 | 14.1 | 12.2 | 12.3 | 13.1 | 13.6 | -1.1% | 0.5% | 13.6 | 13.7 | 13.8 | 13.9 | 13.9 | 14.0 | 14.1 | 14.1 | 14.2 | 14.3 | 79% | 79% |
| Kaikorai Val. | 12/24 + 12/24 | 23 | 22 | 11.8 | 9 | 9 | 10.0 | 11.9 | 10.3 | 0.6% | 1.0% | 10.4 | 10.5 | 10.6 | 10.7 | 10.8 | 11.0 | 11.1 | 11.2 | 11.3 | 11.4 | 49% | 51% |
| Maungawera | 3 | 3.6 | 0 | 1.9 | 2.3 | 1.9 | 2.2 | 2.3 | 2.5 | 3.8% | 3.5% | 2.6 | 2.7 | 2.8 | 2.9 | 3.0 | 3.1 | 3.2 | 3.3 | 3.4 | 3.5 | 94% | N/A |
| Mosgiel | 10 + 10 | See Text | 12 | 14 | 12 | 11 | 11.6 | 11.8 | 12.2 | -2.2% | 3.0% | 12.5 | 12.9 | 13.3 | 13.7 | 14.1 | 14.5 | 15.0 | 15.4 | 15.9 | 16.3 | See Text | 132% |
| Neville St | 15 + 15 | 18 | 18 | 14.2 | 13.6 | 13 | 13.6 | 13.9 | 14.4 | 0.5% | 1.0% | 14.6 | 14.7 | 14.9 | 15.0 | 15.2 | 15.3 | 15.5 | 15.6 | 15.8 | 16.0 | 88% | 88% |
| North City | 14/28 +14/28 | 28 | 28 | 21 | 21.1 | 21.1 | 20.4 | 19.8 | 20.2 | -1.2% | 0.5% | 20.3 | 20.4 | 20.5 | 20.6 | 20.7 | 20.8 | 20.9 | 21.0 | 21.1 | 21.2 | 75% | 75% |
| North East Val. | 9/18 +12/18 | 23.9 | 18 | 11.3 | 11.4 | 10.2 | 11.4 | 10.8 | 10.8 | -0.8% | 0.5% | 10.8 | 10.9 | 10.9 | 11.0 | 11.1 | 11.1 | 11.2 | 11.2 | 11.3 | 11.3 | 47% | 63% |
| Omakau | 3 | 3.6 | 0 | 1.6 | 1.54 | 1.7 | 1.5 | 1.6 | 1.6 | -0.4% | 2.0% | 1.6 | 1.6 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 | 1.9 | 52% | N/A |
| Outram | 3 + 3 | 5.6 | 3.6 | 3 | 2.5 | 2.5 | 2.6 | 2.6 | 2.9 | -0.2% | 0.5% | 2.9 | 2.9 | 2.9 | 2.9 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 54% | 84% |
| Port Chalmers | 7.5 +7.5 | 11.4 | 9 | 8 | 7.5 | 7.6 | 7.9 | 8.1 | 7.9 | 0.6% | 1.0% | 7.9 | 8.0 | 8.1 | 8.2 | 8.3 | 8.4 | 8.4 | 8.5 | 8.6 | 8.7 | 76% | 96% |
| Queensberry | 3 | 3.6 | 0 | 0.5 | 0.6 | 0.8 | 1.4 | 1.6 | 1.9 | 16.5% | 6.0% | 2.0 | 2.1 | 2.2 | 2.4 | 2.5 | 2.6 | 2.8 | 3.0 | 3.1 | 3.3 | 87% | N/A |
| Queenstown | 10/20 +10/20 | 20 | 20 | 18.8 | 18.3 | 18 | 20.4 | 18.3 | 20.2 | 1.4% | 3.0% | 20.8 | 21.5 | 14.1 | 14.5 | 15.0 | 15.4 | 15.9 | 16.3 | 16.8 | 17.3 | 84% | 84% |
| Remarkables | 1 | 1.2 | 0 | 0.8 | 0.8 | 0.8 | 0.8 | 0.7 | 0.8 | -1.1% | 1.0% | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 69% | N/A |
| Roxburgh | 1.5 +1.5 | 3.6 | 1.8 | 2.4 | 2.9 | 1.9 | 1.7 | 2.3 | 2.5 | -1.5% | 0.5% | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.7 | 2.7 | 2.7 | 74% | 148% |
| Smith St | 15 + 15 | 18 | 18 | 18.2 | 19 | 16 | 18.1 | 18.1 | 16.5 | -1.6% | 0.5% | 16.5 | 16.6 | 16.7 | 16.8 | 16.9 | 17.0 | 17.0 | 17.1 | 17.2 | 17.3 | 96% | 96% |
| South City | 9/18 +9/18 | 24 | 18 | 13 | 13 | 11.8 | 13.6 | 14.3 | 15.4 | 3.3% | 2.0% | 15.7 | 16.1 | 16.4 | 16.7 | 17.0 | 17.4 | 17.7 | 18.1 | 18.5 | 18.8 | 77% | 103% |
| St Kilda | 12/24 + 12/24 | 29 | 23 | 15 | 14.7 | 14.7 | 15.1 | 15.2 | 15.4 | 0.8% | 1.0% | 15.6 | 15.8 | 15.9 | 16.1 | 16.2 | 16.4 | 16.6 | 16.7 | 16.9 | 17.1 | 58% | 73% |
| Wanaka | 12/24 +12/24 | 25 | 23 | 11.9 | 11.4 | 11.5 | 13.6 | 14.6 | 15.1 | 5.3% | 5% | 15.8 | 16.5 | 17.3 | 18.0 | 18.9 | 19.7 | 20.6 | 21.5 | 22.5 | 23.5 | 90% | 98% |
| Ward St | 15 + 15 | 23 | 18 | 11.6 | 11 | 10.4 | 10.9 | 10.6 | 11.6 | -0.2% | 0.0% | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 11.6 | 50% | 64% |
| Willowbank | 15 + 15 | 18 | 18 | 14 | 12.2 | 12.1 | 13.7 | 13.7 | 12.8 | 0.0% | 1.0% | 13.0 | 13.1 | 13.2 | 13.4 | 13.5 | 13.6 | 13.8 | 13.9 | 14.0 | 14.2 | 78% | 78% |
| Commonage | 7.5/15+7.5/15 | 15 | 15 | | | | | | | | 4.0% | | | 8.0 | 8.3 | 8.7 | 9.0 | 9.4 | 9.7 | 10.1 | 10.5 | 67% | |
| Morven Ferry | 5 | 6 | 0 | | | | | | | 0.0% | 3.0% | | | | 1.2 | 1.2 | 1.3 | 1.3 | 1.4 | 1.4 | 1.4 | 21% | NA |
| Jacks Point | 7.5/10 | 10 | 0 | | | | | | | 0.0% | 8.0% | | | 2.0 | 2.2 | 2.3 | 2.5 | 2.7 | 2.9 | 3.2 | 3.4 | 22% | NA |

Table 5.6 – Zone Substation Historical and Predicted Demands

5.11.2 **Morven Ferry Substation**

A new substation is 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.

The construction of the 5MVA Coronet Peak substation (2004) has allowed the firm capacity of Arrowtown to be increased from 6 MVA to 7.5 MVA due to the ability to transfer load from Arrowtown to Coronet Peak. This has allowed the construction of the Morven Ferry substation to be deferred. If the mobile substation proposed in Section 5.11.4 proceeds, the firm load allocated to Arrowtown could be further increased which would allow further deferment of the Morven Ferry substation. If the mobile substation does not proceed, it is expected that the Morven Ferry substation will be required by winter 2010. It is possible that there will be low voltage issues in the Gibbston Valley prior to the construction of the Morven Ferry substation which could be mitigated by the installation of a voltage regulator.

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 present combined peak load is 27.9 MW. It is expected it will be 3 to 4 years before the load exceeds 30.8MW.

It is proposed to close the 33kV bus at Mosgiel. This will allow the combined firm load that can be allocated to Mosgiel and East Taieri to increase to 34.3MW. Closing the bus at Mosgiel also avoids the need for the present auto changeover system, and line faults will no longer result in a momentary interruption for consumers. Running with a closed bus at Mosgiel is a significant protection challenge, but initial investigations indicate it is feasible. If the bus is operated closed then only three line breakers will be required at Mosgiel. This project is likely to cost approximately \$300,000. The 11kV switchgear at Mosgiel is also scheduled for replacement in 2008 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.

5.11.5 **Frankton Substation**

Frankton substation has a 7.5/15 MVA and 7.5/10 MVA transformer, each fused off the Frankton to Queenstown 33kV overhead lines. Fuse-only protection of transformers of this size is not ideal. A fault on either of the Frankton to Queenstown lines supplying Frankton results in half the Frankton load being lost until either the line is restored or the 11kV bus section isolator at Frankton is closed. The substation is expected to reach its firm load in 2011.

It is proposed to upgrade the Frankton substation to a more secure transformer-feeder configuration in 2007/8. This project will require the installation of a new 33kV cable from the Transpower GXP to the Frankton substation and the installation of intertripping. The project will utilise the two additional 33kV outlets being provided by Transpower as detailed in Section 5.9.2. This is estimated to cost \$250,000.

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 \$900,000.

5.11.6 Queenstown Substation

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

5.11.7 Cromwell Substation

The Cromwell substation will exceed its firm capacity in the winter of 2010. 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. This would result in no further action being required during the planning period.

5.11.8 Commonage Substation

It is proposed to commission a new substation in the Commonage area on Queenstown Hill in 2009 consisting of two 15MVA transformers. This substation will reduce the load on the Queenstown substation and improve the ability to offload HV feeders in the area. Aurora owns land for a substation in the reserve above the Commonage 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. The cost estimate is \$1,000,000.

5.12 HV Feeders

A feeder's rating is the minimum of its circuit breaker rating, outgoing cable rating, or $1.2 \times$ 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 is monitored by Maximum Demand Indicators (MDIs). This is 78% of the distribution capacity. 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 | 2003 | 2004 | 2005 | 2006 | 2007 |
|-------------|-------|-------|-------|-------|-------|
| Utilisation | 36.7% | 32.5% | 34.2% | 33.6% | 33.2% |

Table 5.7 – Distribution Transformer Utilisation

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

- (1) Subdivisions having transformers designed for a fully occupied subdivision but can take several years for all lots to be connected.
- (2) An increase in the establishment of rural subdivisions with many smaller transformers; for example, the typical utilisation of a 15kVA transformer is only 20%.
- (3) Consultants for new large consumers choosing a connection capacity in excess of their needs.
- (4) Transformers in subdivisions being oversized.
- (5) Consumers adopting Congestion Period Demand (CPD) reduction measures.

- (6) Reduction in consumer loads; for example, use of building changes from a factory to a warehouse.
- (7) Larger diversity between loads; for example, the installation of transformers to supply summer irrigation pumps increases the installed transformer capacity without increasing the peak demand.

The following measures have been introduced to improve utilisation:

- (1) The introduction of headwork's charges has improved the incentives for designers to minimise connection capacity.
- (2) New criteria were introduced into subdivision design standards in 2004 for the sizing of transformers.
- (3) Higher transformer loads than name-plate capacities are now allowed before upgrading a transformer.
- (4) Opportunities to downsize under-utilised transformers are taken when it is economic to do so.

5.14 Reliability and Risk Mitigation Projects

Reliability-initiated projects that will economically reduce the number or duration of consumer outages are 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 5.3 is data on outages per circuit plotted against circuit length⁴. All things being equal, feeders of similar length 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.

OM669, OM679 and EK439 have contributed a high number of faults. To give better supply reliability and reduce momentary interruptions remedial works are planned. The high number of recloser operations on QB218 (without significant outage minutes) were due to a protection setting which had not been adjusted after a significant irrigation load was added. This has since been remedied.

⁴ Figures for circuit lengths have been updated since the 2006 AMP to be based on the 'protective' zone of each circuit breaker.

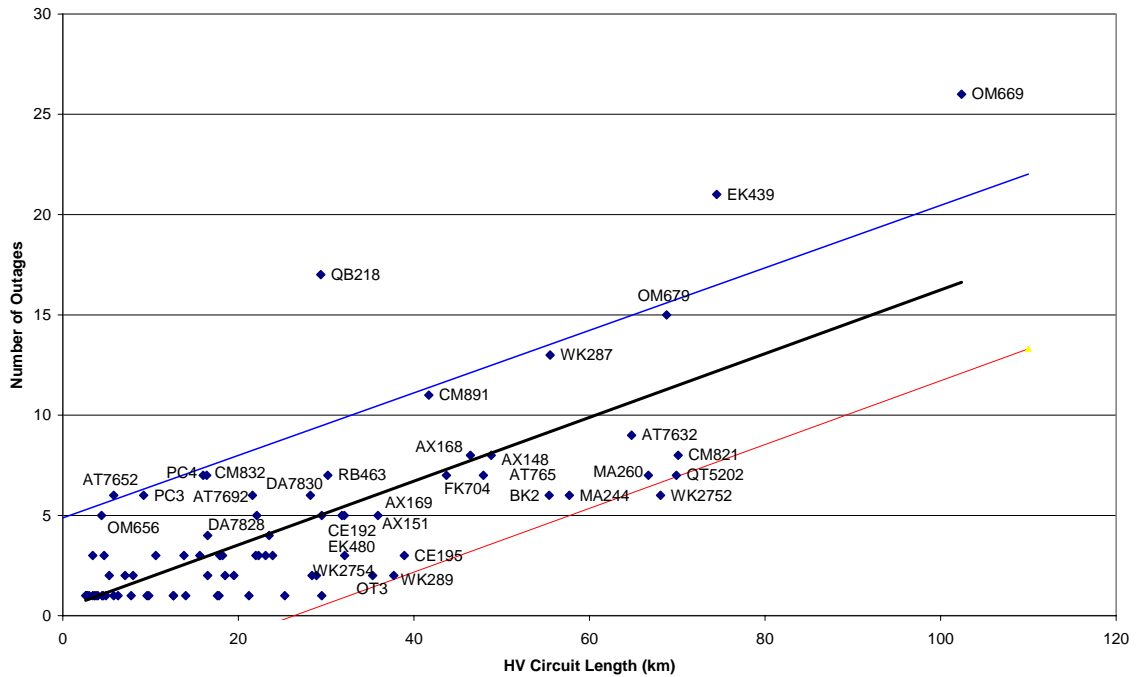


Figure 5.3 – HV Feeder Outages as a Function of Feeder Length (2006)

Another reliability indicator is the system customer outage minutes per HV feeder which is detailed in Figure 5.4. Largely due to simultaneous outages during a high wind event in September 2006, feeders CM832, CM821 and OM669 performed badly. Other feeders with poor performance (PC3, HB1, CE190) do not appear to be indicative of an underlying trend when compared to previous years and will be monitored. The poor performance of OM656 was the result of incorrect protection settings and has since been remedied.

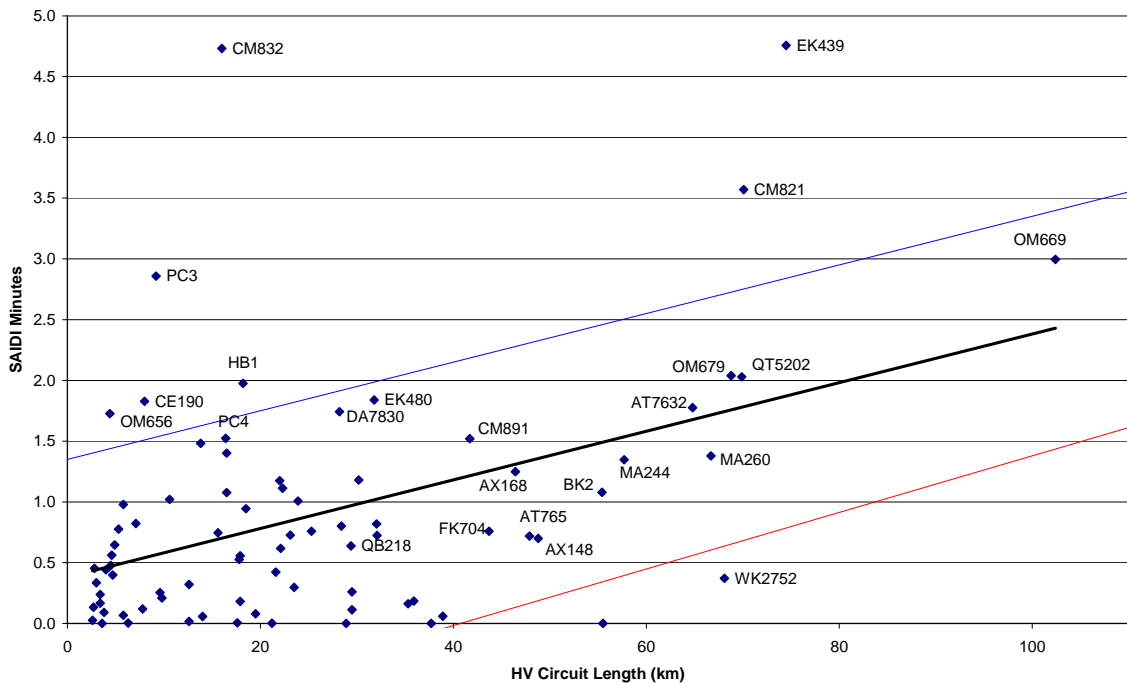


Figure 5.4 – HV Feeder Customer Outage Minutes by HV Feeder (2006)

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 | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 |
|-----------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| DCC | 1,600 | 1,620 | 1,640 | 1,660 | 1,680 | 1,700 | 1,720 | 1,740 | 1,760 | 1,780 |
| CODC | 280 | 290 | 300 | 310 | 320 | 330 | 340 | 350 | 360 | 370 |
| QLDC | | 460 | 470 | 480 | 490 | 500 | 520 | 540 | 560 | 580 |

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, reliability, 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.

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).

Sub-transmission lines undergo detailed inspection every five years and are patrolled annually in the interval.

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

Objective defect criteria are defined for all items and vary between asset types. For some, the key aspect is safety (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 Sub Transmission

Cables

The 33kV underground cables are a mixture of gas filled, oil filled, and solid types. Pressure alarms are installed on the former two and these are tested at six-monthly intervals and the outer sheath integrity on most cables tested annually. Occasionally, leaks develop in these cables, usually at joints or where the cables have been stressed on installation. Faults are expensive to repair, being very labour intensive. The impregnated paper solid insulation type cables are virtually maintenance free but faults occasionally occur due to insulation flow on hill sections or if they have been damaged by third parties (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 and after operation under severe fault conditions. The timeframe between servicing is currently being reviewed with the intention of implementing a condition based programme. Painting of outdoor circuit breakers is undertaken on a rolling basis with major repaints at 10-year intervals.

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

Ripple Injection Plant

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

Miscellaneous

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

Earth connections for all equipment above ground level are inspected and maintained at 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 | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 |
|--------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Sub-transmission | 106 | 109 | 114 | 116 | 119 | 123 | 127 | 130 | 130 | 138 |
| Zone substations | 123 | 127 | 132 | 135 | 139 | 143 | 147 | 152 | 156 | 161 |
| System control | 18 | 18 | 19 | 19 | 20 | 20 | 21 | 22 | 22 | 23 |
| HV and LV | 928 | 956 | 995 | 1,015 | 1,045 | 1,076 | 1,109 | 1,142 | 1,176 | 1,211 |
| Distribution substations | 118 | 122 | 127 | 129 | 133 | 137 | 141 | 146 | 150 | 154 |
| Total | 1,294 | 1,333 | 1,386 | 1,414 | 1,456 | 1,500 | 1,545 | 1,591 | 1,639 | 1,688 |

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 Sub Transmission

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 | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 |
|--------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Sub-transmission | 955 | 984 | 1,023 | 1,043 | 1,074 | 1,107 | 1,140 | 1,174 | 1,209 | 1,246 |
| Zone substations | 1,111 | 1,144 | 1,190 | 1,214 | 1,250 | 1,288 | 1,326 | 1,366 | 1,407 | 1,449 |
| System control | 158 | 161 | 168 | 171 | 176 | 182 | 188 | 196 | 200 | 207 |
| HV and LV | 8,356 | 8,608 | 8,951 | 9,131 | 9,403 | 9,687 | 9,977 | 10,274 | 10,584 | 10,901 |
| Distribution substations | 1,066 | 1,098 | 1,141 | 1,165 | 1,199 | 1,235 | 1,272 | 1,310 | 1,350 | 1,390 |
| Total | 11,646 | 11,995 | 12,473 | 12,724 | 13,102 | 13,449 | 13,904 | 14,321 | 14,751 | 15,193 |

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

6.5 Capital Replacement Projects

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

6.5.1 33kV Gas Cables

Five Dunedin zone substations are supplied by gas insulated 33kV cables detailed in Table 6.3. These cables have been prone to gas leaks and the failure rate has increased significantly since mid 2003. For six months in 2004-05 the failure rate reached 20 failures per 100 km per year which was unacceptably high. Since then the failure rate has reduced.

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

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 Berwick Substation Upgrade

To eliminate the risk of failure, the two 74-year-old Berwick zone substation 0.937MVA transformers and the 58-year-old voltage regulator are to be replaced with a single 3MVA 33/11/6.6kV transformer. The 3MVA transformer has been ordered. The 50-year-old 33kV circuit breaker is also to be replaced. The upgrade will facilitate the eventual conversion of the Berwick area to 11kV distribution. It is expected this project will be completed by winter 2008.

It will enable Berwick and Outram feeders to be paralleled which cannot be done at present because the Berwick transformers are a non standard vector group. It will also eliminate the transient low voltage problems at Berwick experienced during some operating conditions. The cost estimate is \$530,000.

6.5.3 Ward Street Substation Upgrade

The transformers and 6.6kV switchgear at Ward Street were installed in 1938 (69 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 cost estimate is \$3.0 million.

6.5.4 Zone Substation 6.6/11kV Switchgear Replacement

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

| Substation | Manufacture Year | Status | Number CBs | Year* | Cost (\$000) |
|--------------|------------------|---------|------------|---------|--------------|
| Ward Street | 1938 | Planned | 14 | 2009/10 | Note 1 |
| Roxburgh | 1950 | Planned | 1 | 2008/09 | 30 |
| Remarkables | 1950 | Monitor | 1 | | |
| Frankton | 1950 | Planned | 8 | 2008/09 | Note 2 |
| Neville St | 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 6.5.3.

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.

6.5.5 Distribution Circuit Breaker Replacement

A number of distribution substations have oil circuit breakers installed that are in excess of 50 years old, obsolete and becoming expensive to maintain. At present it is not economic to replace 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 |
| Gt King St Rectifier | Reyrolle | 1948 | Monitor | 70 |
| Shacklocks | Statter AC2 | 1960 | Monitor | 70 |
| High Street | Statter AC2 | 1960 | Monitor | 50 |

Table 6.5 – Distribution Substation HV Circuit Breaker Replacement Schedule

6.5.6 Replacement of Ripple Injection Equipment

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

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

Low frequency 33kV injection is preferred because:

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

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.

6.5.7 Dunedin SCADA RTU Replacements

The SCADA remote terminal units at most Dunedin zone substations were purchased in 1987. These units have been very reliable but face technological obsolescence due to their inability to use modern master station communication protocols and communicate with Intelligent Electronic Devices (IEDs) such as protection relays. It is estimated that these would cost \$360,000 to replace. 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 and embedded generation. These are addressed by reducing the design life of assets likely to be bypassed and addressing maintenance expenditure accordingly. All new projects or extensions are considered and proceed only if revenue security is obtained. The following factors underpin many of the network operational decisions.

7.1.1 Risk Management

DELTA has developed and implemented a risk management policy that defines the approach taken to manage risks associated with the management of Aurora's electricity line business. The primary strategy of this policy is to document all significant risks as they are identified, together with the policies and procedures for eliminating, reducing and managing the consequences of each risk event. 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 | |
| | Fraud | <ul style="list-style-type: none"> Fraud and Other Similar Irregularities policy |

| Generic Risk Area | Sub-Category | Policy Reference |
|---------------------|--|--|
| | | <ul style="list-style-type: none"> Protected Disclosures policy Delegations Policy |
| Information systems | Financial systems | |
| | Archives | |
| | 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.

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 programmed to be completed over the next three years on a priority basis.

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 a year 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 ⁵ |
| South Dunedin | 100 | - | Yes |
| Clyde | 60 | 17 | Yes |
| Frankton | 38 | 2 | No ⁶ |
| Cromwell | 30 | 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 redundancy which either avoids an interruption or shortens restoration times;
- asset condition which affects the likelihood of failure of a component;
- operation practices which reduce restoration time.

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

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

7.1.5 Safety

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

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,

⁵Refer to Section 5.9.5

⁶Refer to Section 5.9.2

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 Physical Performance

8.1.1 Reliability

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

| Category | 06-07 Plan | 06-07 Actual |
|----------------------------|----------------------|----------------------|
| SAIDI | Minutes | Minutes |
| Unplanned | | |
| Underlying | 64 | 61.3 |
| Significant events | 10 | 22.3 |
| Planned | 5 | 13.2 |
| | 89 | 96.7 |
| Transpower | 1 | 4.7 |
| TOTAL | 90 | 101.4 |
| SAIFI | Interruptions | Interruptions |
| Unplanned by Aurora | 1.36 | 1.59 |

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

For unplanned interruptions, the “underlying” pattern was 2.7 minutes below target. However, significant events were significantly over target mainly due to severe winds on 1 and 2 September and 12 and 13 October 2006. Transpower interruptions were over target by 3.7 minutes. These events resulted in the total being 12.6% over target.

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

The secondary performance measure is “unplanned by line owner SAIFI” as described in Section 4.1. As this was over target by 17%, investigations into the cause of this are on-going and remedial measures are currently being considered.

Planned interruptions were 8.2 minutes above the 06-07 target figures reflecting the high level of network growth.

8.1.2 Faults per 100km HV Circuit

The number of faults per 100km line for the year 1st April 2006 to 31st March 2007 is 13.3. This is an increase of 20% over the previous financial year.

As a result of this tree trimming is to be targeted at selected problem feeders.

8.1.3 Low Voltage Complaints

Fifteen valid voltage complaints were received for the year 1st April 2006 to 31st March 2007. This is a decrease of 14 from the previous year reflecting the relatively mid winter in 2005-06.

8.1.4 Environmental Performance

There were no reported environmental incidents for the year 1st April 2006 to 31st March 2007.

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 | 2006/07 Actual (\$000) | 2006/07 Budget (\$000) | Variance (\$000) | |
|----------------------------|------------------------------|------------------------------|---------------------|------|
| Sub-Transmission | 762 | 500 | 262 | 52% |
| Zone Substations | 1,602 | 1,220 | 382 | 31% |
| System Control | 80 | 109 | -29 | -27% |
| HV and LV Lines and Cables | 7,992 | 7,760 | 232 | 3% |
| Distribution substations | 1,270 | 1,367 | -96 | -7% |
| Total | 11,706 | 10,955 | 751 | 7% |

Table 8.2 – Operating and Maintenance Expenditure Budget Compared to Actual

The causes for the variances are:

- the sub-transmission system unfavourable variance was caused by a higher than expected fault incidence of 33 kV faults in Dunedin (five). This result is the direct opposite to the previous year;
- the zone substation unfavourable variance was caused by the faults to the Halfway Bush T2 and Omakau transformers;
- the SCADA upgrade completed early in 2006 combined with good support under a new maintenance agreement with the Australian supplier continues to be the reason for the positive variance in System Control costs

- HV and LV lines and cables were over budget due to increased tree trimming and fault repair work

8.2.2 Capital Expenditure

The budget below is the final 2006/07 budget including authorised additional expenditure approved by the Board.

| Category | 2006/07 Actual (\$000) | 2006/07 Budget (\$000) | Variance | |
|---------------------------------|------------------------------|------------------------------|----------|------|
| | | | (\$000) | |
| New connections | 9,580 | 7,200 | 2,380 | 33% |
| Localised growth | 4,377 | 2,200 | 2,177 | 98% |
| System development | 1,040 | 898 | -142 | 16% |
| Undergrounding projects | 2,353 | 3,308 | -955 | -29% |
| Upgrade Berwick zone substation | 30 | 430 | -400 | -93% |
| Tarras substation | 10 | 550 | -540 | -98% |
| Cromwell 11 kV switchgear | 624 | 909 | -285 | -31% |
| Closeburn regulators | 158 | 150 | 8 | 5% |
| Total | 18,172 | 15,625 | 2,547 | 16% |

Table 8.3 – Comparison of Actual Capital Expenditure with Plan

An “explosion” in subdivision development saw capital expenditure in the New Connections and Local Growth categories exceed budgets by \$4.6 million or 48%. Delays to other projects, partially caused by manpower diversion to the growth explosion, resulted in total capital expenditure only exceeding budget by \$2.5 million or 16%.

The causes for the variances are:

- Overall, capital expenditure was ahead of budget projections, mainly due to customer demand as customer driven new connections were higher than budget by 33%.
- Localised growth is a combination of planned works required to meet growth and works required for the correction of voltage complaints. This was higher than budget reflecting Aurora’s determination to facilitate development.
- Undergrounding is behind budget due to late Local Body approval of projects and the deliberate diversion of resources to service customer driven and load growth projects.
- The Berwick substation project was delayed due to longer than anticipated transformer specification (by external consultants) and purchasing lead times and has been deferred for completion in the 2007/08 year.
- The Tarras substation was put on hold as detailed in section 5.11.4.
- The Cromwell 11 kV upgrade was completed under budget over a two year period.

8.3 Gap Analysis and Identification of Improvement Initiatives

Both planned and unplanned maintenance activities are analysed to monitor performance trends and to evolve both maintenance practices and replacement policies. No changes to current practices have been identified in the last year.

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

Recently identified improvements have included:

- dual supply to the Clyde Earnsclough substation (completed);
- replacement of the 11kV Cromwell switchgear and duplication of the 33kV supply to this zone substation (completed);
- Berwick zone substation upgrade (approved and underway);
- closing the 33 kV bus at Mosgiel to reduce momentary interruptions (proposed);
- voltage regulators to be installed at the Pisa Moorings (approved);
- reclosers to improve reliability at the Ettrick and Poolburn areas (approved);
- Scada improvements to the Central network (ongoing)
- Data quality improvements to the GIS records when economic to do so.

9 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 Project Listings

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

| Year | Project Name | Status | Value (\$000) | Section # |
|------|--------------------------|----------|---------------|-----------|
| 2007 | Berwick Transformer | Underway | \$530 | 6.5.2 |
| 2007 | Queenstown Cables | Planned | \$822 | 4.10.1 |
| 2007 | Frankton 33 kV Cables | Planned | \$250 | 5.11.2 |
| 2008 | Cardrona Generation | Planned | \$500 | 4.10.2 |
| 2008 | Mosgiel Substation | Proposed | \$950 | 5.11.3 |
| 2008 | Mobile Substation | Planned | \$1,400 | 5.11.4 |
| 2009 | Commonage substation | Underway | \$5,000 | 5.11.8 |
| 2009 | Wanaka to Hawea Line | Proposed | \$1,000 | 4.10.3 |
| 2009 | Frankton Switchgear | Proposed | \$900 | 5.11.3 |
| 2010 | Ward St switchgear | Proposed | \$3,000 | 6.5.3 |
| 2010 | Morven Ferry Substation | Proposed | \$1,000 | 5.11.2 |
| 2010 | Jacks Point | Proposed | \$1,000 | 5.11.9 |
| 2011 | Dunedin Ripple Injection | Proposed | \$1,450 | 6.5.6 |

10 APPENDIX B – 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 prioritization 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 |
| 4.5.6 | Lifecycle Asset Management Planning (Maint & 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 | 6.1 6.2 6.3 |

| | | |
|--------------|---|--|
| | (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 | 6.3 6.4, 6.5 |
| 4.5.7 | Risk Management (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 (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 |